REPORT OF THE

THREE MILE ISLAND ACCIDENT REVIEW TASK FORCE

WISCONSIN ELECTRIC POWER COMPANY

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EXECUTIVE SUMMARY

THREE MILE ISLAND ACCIDENT REVIEW TASK FORCE

The accident at Unit 2 of the Three Mile Island (TMI) Nuclear Plant on March 28, 1979, was the most serious commercial nuclear power plant accident that has occurred to date in this country. A Three Mile Island Accident Review Task Force was formed immediately after the accident and began its formal activity on April 14, 1979. This Task Force is composed of personnel within the Milwaukee office who have intimate knowledge and experience with the design, construction, licensing, and operation of the Point Beach Nuclear Plant (PBNP). The majority of the Task Force members have held Senior Reactor Operator licenses and were involved in the management and operation of the PBNP.

This Summary outlines the Task Force activities in the five areas examined and presents the conclusions and recommendations which were reached. The areas examined were:

1. The TMI Accident
2. The TMI Plant as Compared to the PBNP
3. PBNP Procedures and Operations
4. PBNP Design Features
5. PBNP Emergency Planning

The examination of each area was conducted to analize the TMI accident in relation to PBNP, to determine and correct any deficiencies, and to improve current plant operations, including consideration of continued operation of the PBNP. In addition, the Task Force undertook a broad view of nuclear plant design philosophy in light of the TMI accident.

CONCLUSIONS AND RECOMMENDATIONS OF THE TASK FORCE

The conclusions and recommendations resulting from this evaluation are being made to improve the operational capability of PBNP and are not needed to correct any major deficiency in existing plant equipment, systems, procedures, or personnel.

The Task Force considered whether the Point Beach Nuclear Plant should be shut down as a result of any deficiency or unsafe condition recognized or discovered during its review and evaluation activities. It is the unanimous conclusion of the Task Force that the Point Beach Nuclear Plant has been, and will continue to be, operated in a safe manner which complies in all respects with the provisions of its operating licenses, the regulations of the Nuclear Regulatory Commission, and the directions of senior corporate management. The Task Force further concludes that, in light of our present knowledge of the TMI events and those reviews identified in this report, continued operation of the Point Beach Nuclear Plant can be conducted without undue risk to the public health and safety, or to the health and safety of the employees who are charged with its safe operation.

The Task Force conclusions and recommendations are the following:

1. Auxiliary feedwater system status indication should be upgraded with a ready status panel and individual train flow indication in the control room.

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2. Emergency procedures should be revised to better identify, control and recover from voids.

3. Specific conditions for termination of safety injection should be specified in emergency procedures.

4. More detailed guidance on identifying and isolating leaks via the power operated relief valves should be provided.

5. The current program for simulator training of operators in the area of emergency operation are adequate and should continue.

6. Additional TMI information should be reviewed with the PBNP licensed personnel and plant staff as it becomes available.

7. A remotely operated vessel head vent should be further studied, although not needed based on current vent capabilities.

8. Further studies should be conducted to assess post-accident consequences of possible sampling and access to equipment problems due to the potential for elevated radiation levels in the auxiliary building.

9. Post-accident hydrogen control is acceptable. However, to further reduce the potential for any radioactive releases during an accident, a preliminary engineering study should be performed to determine the system design and cost for accommodating a hydrogen recombiner more readily than presently allowed.

10. Full flow testing of the auxiliary feedwater pumps on a monthly basis is neither necessary nor desirable.

11. Natural circulation has been tested and confirmed to be completely acceptable. Improvements can and should be made in instrumentation to monitor the status of natural circulation using hot leg RTDs and incore thermocouples.

12. Control board information should be provided to aid the operator in identification of the potential for void formation by continuously recording primary coolant system pressure and a calculated saturation pressure.

13. Utilization of the steam generators to cool the primary system to below 200°F is feasible.

14. The industry should verify the adequacy of LOCA calculations to model steam condensing cooling of primary coolant using the steam generators.

15. No changes are needed to containment isolation, pressurizer PORV status indication, pressurizer level, or containment sump level instrumentation.

16. Reactor vessel level instrumentation during accident conditions is not required.

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17. In-containment radiation monitoring devices are deemed unnecessary for post-accident conditions.

18. The performance of PBNP operators relative to their experience should be compared. If any significant trend can be demonstrated, measures should be taken to improve the performance of any lower ranking group in order that the present overall level of competence be maintained and improved in the future.

19. The PBNP Emergency Plan and its activation criteria are adequate. Improvements to the Plant can result from: a review of the order of notification; notification of both the State of Wisconsin, Division of Emergency Government and the Department of Health and Social Services, Section of Radiation Protection; review of portable instrument location, availability and adequacy, and further efforts to improve interfaces with local agencies.

20. Government agency and news media access and participation during and following an accident should be developed on a predetermined basis.

PHILOSOPHY OF NUCLEAR PLANT DESIGN

The philosophy of nuclear plant design as related to Three Mile Island and other pressurized water reactor systems was examined by the Task Force.

To put the Three Mile Island accident in focus, the Task Force considered the three significant aspects with respect to fulfilling the commitment to conservatism in the protection of the fissionable material contained within the reactor core. These three aspects ranked in order of importance are:

1. "Passive" design aspects

2. "Active" design aspects or equipment (functioning and reliability)

3. People

The most important aspect is "passive" design, which by its very nature is usually rugged, simple, and always present. It presently provides a substantial part of the protection of operating nuclear cores. The use of "passive" design concepts, such as inventory and size, equipment layout, gravity and pressure differential, should be maximized in the design of nuclear power plants. "Active" design or equipment should be used when a "passive" design cannot be achieved. The nuclear industry has shown that a high degree of reliability for "active" components with the use of redundancy can be achieved. The third and ultimate aspect to assure the protection of the core is "people". Their proper selection and training is essential.

Based on evidence to date, the Task Force sought to determine whether the accident was caused by inappropriate operator action or by a plant design that the operators could not easily control. It is the opinion of the Task Force members that the root causes of the TMI accident appear to be a combination of inappropriate

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selection, application, and approval of marginal "passive" design concepts, the substitution of insufficient "active" design or "gadgeteering" in its stead, and some inappropriate operator action or inaction.

Now that the TMI accident has happened, it is appropriate to reevaluate previously held positions on assured core protection.

AREAS OF REVIEW AND EVALUATION

1. THE TMI ACCIDENT

The Task Force's initial effort was to gather information on the TMI accident and to attempt to understand the sequence of events which followed. This effort involved a gathering of information from sources such as the NRC, Babcock and Wilcox (the reactor system vendor), Metropolitan Edison (the operating utility), Nuclear Safety Analysis Center (NSAC), and other industry sources. A time history sequence of events in the report gives a detailed description of the accident, operator and equipment actions, and plant responses for the time period from just prior to the accident through the relatively stable condition about fourteen hours later. Plant parameter transient curves are also included to explain the actions and responses. The Task Force report examines the major actions taken or omitted during the accident and provides an evaluation of the consequences. This autopsy identifies the major contributors to the accident summarized as follows:

A. Failure of TMI operating personnel to recognize the open pressurizer electromatic relief valve which allowed an extended period of reactor coolant loss from the primary system and its depressurization below saturation resulting in steam formation and core uncovery.

B. Basic system design features which made heat removal from the core using natural circulation through the steam generators difficult to establish, monitor, and maintain.

C. Premature termination of the high pressure safety injection which stopped the addition of water to the reactor coolant system which was balancing the system losses.

D. Pressurizer surge line arrangement, instrumentation, and procedures which provided misleading information to the operating personnel and hindered them in determining the condition of the plant.

E. Isolation of the emergency feedwater system flow to the steam generators during the first eight and one-half minutes removing the basic heat sink and increasing the initial magnitude of the transient.

F. Control and protection system designs which did not anticipate accident producing conditions but waited for the parameter response to actuate the protective action. This increased the initial magnitude of the transient because reactor trip was delayed. Similarly, releases of radioactive water from the containment to the auxiliary building occurred because containment pressure did not get high enough to cause containment isolation during the first four hours and twenty minutes of the accident.

2. THE TMI PLANT AS COMPARED TO THE PBNP

After the accident and its events were documented, the Task Force objective was to understand the TMI plant and equipment so that it could be compared to the PBNP. Similar systems could then be examined relative to the part that each system played in the accident. Likewise, system differences could also be evaluated to determine if they would have a positive or negative impact on a hypothetical TMI-type accident imposed on the PBNP design. This evaluation led to the conclusion that the TMI event is not possible at PBNP because of basic design differences, but a similar event of less consequence could occur as analyzed in the Final Facility Description and Safety Analysis Report (FFDSAR) under the small break LOCA event. The small break and other transients were, therefore, considered in more detail relative to a Westinghouse pressurized water reactor (PWR) design such as PBNP. Related events of a nature similar to the TMI accident which have occurred at PBNP were also reviewed and no deficiencies in design, equipment, training, or procedures were identified. For the PBNP events, all equipment failures or malfunctions experienced to date had been promptly corrected and the plant returned to service without affecting the health and safety of the public. Operator training programs were checked to verify that each event was already included in the training program and changes were made if needed.

3. PBNP PROCEDURES AND OPERATIONS

The procedural and operational review conducted by the Task Force focused on evaluating the adequacy of existing procedures and methods of operations to prevent the conditions which led to the TMI accident, to deal with anticipated transients and accidents, and to facilitate recovery from any similar condition. The major areas examined were the following:

A. Auxiliary feedwater isolation
B. Stuck open power operated relief valve
C. Void formation
D. Termination of Engineered Safety Features system operation
E. Reactor coolant pump operation during accidents
F. Uncontrolled release of reactor coolant from containment to the auxiliary building
G. Control of hydrogen in containment
H. Control and monitoring of natural circulation
I. Training considerations

4. PBNP DESIGN FEATURES

The design features of the PBNP were reviewed by the Task Force to determine if any equipment or systems should be changed as a result of the TMI accident. The major plant systems and equipment investigated were the following:

A. Venting the reactor vessel head and the pressurizer
B. Sampling considerations during accidents
C. Dealing with hydrogen following a LOCA

D. Auxiliary feedwater system testing
E. Natural circulation capability of the primary system
F. Steam condensing capability of the steam generator
G. Utilization (steam generators to cool the primary system below 200°F
H. Radiation considerations of piping systems in the auxiliary building during and following a LOCA
I. Pressurizer low pressure plus low level coincidence to actuate safety injection
J. Incore thermocouples and hot leg temperature instrumentation
K. Actuation, isolation and reset features of Engineered Safety Features systems
L. Pressurizer PORV position and flow indication
M. Pressurizer level instrumentation
N. Containment sump water level instrumentation
O. Reactor vessel level instrumentation
P. In-containment radiation monitoring instruments following a LOCA
Q. Review of environmental qualification of in-containment instrumentation and equipment

5. PBNP EMERGENCY PLANNING

The current PBNP Emergency Plan was reviewed by the Task Force to assure the adequacy of the Plan in the following areas:

A. Recognition of accidents
B. NRC notification
C. Other agency notification
D. News media and government agency involvement during and following an accident
E. Environmental and public monitoring during and following an accident
F. Adequacy of State plans and interface between State and utility.

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SECTION 1

THREE MILE ISLAND ACCIDENT REVIEW TASK FORCE

1.1 TASK FORCE CHARTER AND PURPOSE

The accident at Unit 2 of the Three Mile Island (TMI) Nuclear Plant is the most serious commercial nuclear power plant accident that has occurred to date in this country. It is necessary and prudent that this event be carefully evaluated to determine the extent to which it may affect Wisconsin Electric Power Company's present and future nuclear operations. To accomplish this objective, a Three Mile Island Accident Review Task Force was appointed to assure that continued operation of the Point Beach Nuclear Plant (PBNP) does not present any undue hazards to the public health and safety or to the health and safety of the employees who are charged with its safe operation and maintenance.

The Task Force was directed to undertake a number of activities in relation to the Three Mile Island accident, its analysis, and its impact on Wisconsin Electric's nuclear activities. These immediate actions comprise the following:

A. Establish and catalog the sequence of events at Three Mile Island Unit 2 from all available sources, updating this chronology as frequently as information permits until the accident is terminated.

B. Review the design and arrangement of the Three Mile Island Plant, noting the differences and similarities between that facility and the Point Beach Nuclear Plant, to determine whether the sequence of events experienced at Three Mile Island could occur at Point Beach and, if they could, the results of such a similar sequence. Determine the differences between the facilities which would exacerbate or mitigate against such a sequence of actions, including those related to design, equipment, and operating procedures.

C. Determine for Point Beach Nuclear Plant whether any equipment, design, system, operating procedure, maintenance program, or personnel qualifications or training should be modified or changed as a result of the Three Mile Island accident. This should include consideration of plant shutdown.

To accomplish these activities, a Task Force within the Milwaukee office was formed consisting of personnel who have intimate knowledge and experience with the Point Beach Nuclear Plant and the technical disciplines to evaluate and report on these matters. Their evaluations were based on the technical aspects of the Point Beach Nuclear Plant operation and consist of the identification of areas of concern and improvements to systems, equipment, training, and procedures. The organization of the plant and Nuclear Projects Office within Wisconsin Electric was not addressed. Implementation of recommendations will proceed using the normal safety and licensing review and approval procedures required for all plant changes.

In addition to the establishment of this Task Force, Westinghouse Electric Corporation was retained to provide additional assistance to aid in Wisconsin Electric's understanding of the Three Mile Island events and the accident's impact on Westinghouse designed plants.

The Task Force was appointed by the Executive Vice President responsible for nuclear activities and given full authority to conduct its assignment including access to all information, people and resources necessary for its work.

1.2 TASK FORCE ORGANIZATION

The following personnel comprise the TMI Accident Review Task Force providing expertise in the areas indicated:

Mr. R. A. Newton, Chairman	Reactor and Safety Analysis
Mr. T. A. Hanson	Instrumentation and Control
Mr. C. W. Krause	Licensing and Safety Analysis
Dr. E. J. Lipke	Radiological Engineering and Emergency Planning
Mr. T. J. Rodgers	System Engineering and Operations
Mr. L. F. Storz	Operating Procedures and Training

Mr. S. A. Schellin joined Wisconsin Electric after the formation of the Task Force and has participated in the functions of the Task Force as a consultant and contributor to the report.

A compilation of the qualifications of each member of the Task Force is given below indicating current position, education, work experience, and licenses held at nuclear facilities. In addition to these designated members of the Task Force, contributions to this effort were given by personnel from other departments within Wisconsin Electric including the Point Beach Nuclear Plant staff.

Mr. R. A. Newton is currently the Senior Nuclear Engineer for Wisconsin Electric Power Company. He has held this position since 1973. Mr. Newton's major areas of responsibility include design and safety analysis of the reactor cores, plant instrumentation and protection systems, plant electrical systems, turbine-generator, and storage and handling of spent fuel. From 1968 to 1973, Mr. Newton was the Reactor Engineer at the Point Beach Nuclear Plant. He participated in training of the original complement of licensed operators in the areas of nuclear physics, reactor operation, plant transient response and accident analysis. He was responsible for initial plant startup testing and core loading to full power operation. Mr. Newton obtained a Senior Reactor Operator license for the Point Beach Nuclear Plant in 1971. From 1966 to 1968, Mr. Newton was assigned to Westinghouse to gain experience in the design and startup of nuclear plants. He assisted Westinghouse engineers in evaluation of nuclear plant operating data, determination of control system setpoints and startup of the San Onofre and Connecticut Yankee Nuclear plants. Mr. Newton worked for Westinghouse Electric Corporation at the Bettis Atomic Power Laboratory from 1964 to 1966 on testing and evaluating of steam generator operating characteristics. Mr. Newton attended the six month Bettis Nuclear Power School on a full-time basis during the first half of 1966. Mr. Newton was graduated from the University of Wisconsin in 1964 with a bachelor of science degree in mechanical engineering.

Mr. T. A. Hanson is currently the Superintendent of the Startup and Inspection Division for the Wisconsin Electric Power Company. He has held this position since 1978. Mr. Hanson's major areas of responsibility include the startup of new generating facilities, transmission lines, substations, and power plant betterment projects. From 1967 to 1978, Mr. Hanson was the Instrument and Control Engineer at the Point Beach Nuclear Plant. He participated in training the original complement of licensed operators in the areas of instrumentation, control, and reactor protection systems. From 1967 to 1968, Mr. Hanson was assigned to various Westinghouse plants and facilities to gain experience in the design and startup of nuclear plants. As Instrument and Control Engineer, his major areas of responsibility were design, calibration, testing, and maintenance of instrumentation and control equipment. Mr. Hanson obtained a Senior Reactor Operator license for the Point Beach Nuclear Plant in 1974. At that time, he was assigned additional duties as a Duty and Call Superintendent. From 1960 to 1967, he was assigned to various Wisconsin Electric fossil-fueled power plants as a Test Engineer specializing in instrumentation and control. Mr. Hanson was graduated from the University of Wisconsin in 1960 with a bachelor of science degree in mechanical engineering.

Mr. C. W. Krause is currently Licensing Engineer at the Wisconsin Electric Power Company. He has held this position since 1976 and worked in nuclear power plant licensing at the Wisconsin Electric Power Company since 1972. He has also assisted in the preparation of the PSAR and Environmental Report for the proposed Haven Nuclear Plant. From 1968 to 1972, Mr. Krause was a commissioned officer in the United States Navy. He completed the Navy Nuclear Power Program and served as Electrical Officer on board the USS ASPRO (SSN648). While in the Navy, Mr. Krause qualified as an Engineering Officer of the Watch on the S1C prototype reactor and on the S5W submarine nuclear power plant. Mr. Krause was graduated from the University of Wisconsin in January 1968 with a bachelor of science degree in electrical engineering.

Dr. E. J. Lipke is currently a Senior Project Engineer for the Wisconsin Electric Power Company. He has held this position since March, 1979, and worked as a Project Engineer (nuclear plant engineer) in the Nuclear Projects Office since 1974. His present responsibilities include corporate health physics, regulatory affairs and nuclear fuel processing. His previous work experience included the position of senior scientist at Bettis Atomic Power Laboratory (Westinghouse) and radiological engineer at Vallecitos Nuclear Center (General Electric). Dr. Lipke received a bachelors of science degree in biology and chemistry from the University of Detroit in 1964, a masters degree in radiological health from Wayne State University in 1965, a master of science degree in radiological health from the University of Michigan in 1967, and a doctoral degree in radiological health from the University of Michigan in 1971.

Mr. T. J. Rodgers is presently employed by Wisconsin Electric Power Company as Assistant Manager, Power Plant Betterment and Facilities Engineering. As such, he is the engineering manager responsible for engineering of fossil plant modifications and all other Company owned buildings. From November 1975 to November 1978, Mr. Rodgers was the Project Superintendent at the Point Beach Nuclear Plant and had overall responsibility for major new construction and backfitting at the Plant. From January 1973 to October 1975, Mr. Rodgers was in charge of the Company's Nuclear Projects Office. As manager of the Nuclear Projects Office, he was responsible for all phases of Company involvement in nuclear power engineering at the corporate level. Mr. Rodgers' original duties with Wisconsin Electric were as Operations Superintendent for the Point Beach Nuclear Plant. He held this position from August 1967 to December 1972. From 1970 to 1973, Mr. Rodgers held a NRC Senior Reactor Operator license for the Point Beach Nuclear Plant. Prior to his employment with Wisconsin Electric Power Company, Mr. Rodgers was employed by Westinghouse Electric Corporation. He spent four years as an Operations Supervisor at the AIW Prototype National Reactor Testing Station and six years as a quality assurance engineer at the Bettis Atomic Power Laboratory. From October 1952 to June 1957, Mr. Rodgers

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was a special weapons and explosives ordinance disposal officer in the United States Navy involved in developing safety procedures for nuclear and conventional ordinance. Mr. Rodgers graduated from the University of Missouri with a bachelors degree in Chemical Engineering and received a MBA degree from the University of Pittsburgh in 1961.

Mr. L. F. Storz is currently Fire Protection Officer for the Wisconsin Electric Power Company system. He has held this position since 1977. As Fire Protection Officer, he is responsible for all corporate fire protection programs including the Point Beach Nuclear Plant Fire Protection Plan. From 1972 to 1977, Mr. Storz was a technical assistant and later the assistant to the Operations Superintendent at the Point Beach Nuclear Plant. His responsibilities during that time included development and review of operational procedures, responsibility for refueling operations, and coordinating operational inspections conducted by the NRC. During this period, Mr. Storz held a Senior Reactor Operator license for the Point Beach Nuclear Plant. Prior to his employment with Wisconsin Electric Power Company, Mr. Storz worked for Babcock and Wilcox Company's nuclear power generation division as a contract system engineer specializing in a safeguard system design and operation. He graduated in 1970 from Purdue University with a bachelors degree in mechanical engineering. Prior to college, Mr. Storz was enlisted in the United States Navy where he served as a nuclear reactor operator in the submarine service. During this time, he qualified on the S3G and S5W reactor plants and completed the Navy Nuclear Power School.

Mr. S. A. Schellin is currently Project Engineer-Nuclear Design for the Wisconsin Electric Power Company. He came to this position in April of 1979 from Westinghouse Electric Corporation where he had been employed since 1966 in various divisions of the Nuclear Energy Systems, Power Systems Company. Mr. Schellin was graduated from the University of Wisconsin in June 1964 with a bachelor of science degree in nuclear engineering and in January 1971 with a master of science degree in nuclear engineering. He has done post graduate work in nuclear engineering, mathematics, and computer science at the Pennsylvania State University, the University of Pittsburgh, and Carnegie - Mellon University, respectively. From 1966 to 1967, Mr. Schellin worked in engineering training for the Westinghouse Educational Department. From 1967 to 1972, he performed nuclear design, shielding, and fuel management analyses for liquid metal fast breeder reactors, including the Fast Flux Test Facility, for the Westinghouse Advanced Reactors Division. From 1972 to 1977, he was a Senior Licensing Engineer in the Pressurized Water Reactor Systems Division responsible for reactor safety analysis evaluations, generic fuel design technical licensing, and reload nuclear design and licensing for operating Westinghouse plants. From 1977 to 1979, he was a Training and Senior Audit Engineer in the Nuclear Service Division providing reactor operator, senior reactor operator, and plant personnel training and audit examinations in the classroom and plant, as well as using reactor simulators.

1.3 TASK FORCE ACTIVITIES

The Task Force was initially defined on April 2 with preliminary guidelines being provided on request in a memorandum from the Director of Nuclear Power Department Mr. C. W. Fay to Executive Vice President Mr. Sol Burstein. Mr. Burstein's memorandum of April 14 officially authorized the Task Force by defining its objectives and identifying its members. The various activities of the Task Force and its members are briefly described below.

April 5, 1979 - T. J. Rodgers attended the Westinghouse meeting on Three Mile Island. The event was reviewed, potential areas for review identified and the assisting Westinghouse organization identified.

April 6, 1979 - First Task Force meeting. Mr. Rodgers presented information obtained at the April 5 Westinghouse meeting. An initial sequence of events of the incident was developed. General areas of assignment were made.

April 9, 1979 - Second Task Force meeting. The Nuclear Regulatory Commission (NRC) Staff's briefing to the Commissioners was reviewed. Specific assignments were made from NRC IE Bulletin 79-05, Westinghouse check lists, and other items as identified by the Task Force.

April 17, 1979 - Third Task Force meeting. The detailed TMI accident sequence of events and plant parameter transient curves was reviewed. Assignments were made of Bulletin 79-06A sections for preparation of responses to the NRC.

April 20, 1979 - NRC meeting at Point Beach. Mr. Rodgers and Mr. Fay attended the meeting. NRC provided an update of TMI accident to plant operators.

April 20, 1979 - Westinghouse TMI meeting. Messrs. Newton, Hanson, and Schellin attended. An update of the TMI events was presented. In addition, pressurizer low level plus low pressure safety injection actuation and the Westinghouse recommended operator actions to terminate safety injection and reactor coolant pump operation were discussed.

April 24 and 25, 1979 - Fourth Task Force meeting. The Task Force watched a videotape of the April 20 NRC/PBNP meeting. A presentation was made on the Westinghouse April 20 meeting and responses to Bulletin 79-06A were reviewed.

April 26, 1979 - NRC meeting on Westinghouse plants. Items discussed were small breaks, loss of feedwater, natural circulation, and pressurizer power operated relief valve operation. Mr. Newton attended.

May 3, 1979 - Fifth Task Force meeting. A presentation was made on the topics of the NRC meeting of April 26. A review of the Task Force report outline and initial review of draft sections of the report were discussed.

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May 10, 1979 - ACRS meeting attended by Westinghouse, NRC Staff, and utility representatives. The topics discussed included responses to IE Bulletin 79-06A, small break LOCA, natural circulation and reactor vessel level instrumentation. Mr. Newton attended.

May 11, 1979 - Mr. Newton and Mr. Forrest Rhodes, Point Beach Nuclear Plant Superintendent - Operations, attended a meeting with the NRC Staff concerning specific questions on the auxiliary feedwater system and related components.

May 23, 1979 - A second general meeting was held by Westinghouse for licensees. The topics covered included events and actions taken by Westinghouse since TMI, small break LOCA analyses, secondary side transients, recommended and suggested procedure changes and design modifications, and Westinghouse training programs. Mr. Schellin attended.

May 24, 1979 - Sixth meeting of the Task Force. The Task Force reviewed the meetings of May 10 and 23, discussed completion of review objectives, discussed the NRC staff review of Bulletin 79-06A responses, and discussed the direction of the TMI review following completion of the report.

May 30, 1979 - Mr. Fay and Mr. Newton attended an upper management level meeting of utilities with Westinghouse plants which was held by the NRC in Bethesda to discuss the responses to Bulletin 79-06A. The NRC suggested that a Utility Owners Group be formed to facilitate resolution of its outstanding concerns. On the following day, May 31, 1979, the NRC met with the technical representatives and listed the various small break concerns it wished to have resolved in the next two weeks.

June 5, 1979 - Utility representatives held a meeting in Chicago to terminate previous arrangements and to form a Westinghouse designed-plant Utility Owners Group. Working groups on technical issues and on plant procedures were also appointed. Westinghouse was given directions by the Utility Owners Group to proceed with the small break analyses as requested by the NRC. Mr. Newton attended and currently heads the plant procedures working group.

June 6 and 7, 1979 - Seventh meeting of the Task Force. The meetings of May 30 and June 5 were reviewed. The entire draft of the Task Force Report was reviewed in detail. Report recommendations and conclusions were discussed and revised.

June 14, 1979	Mr. Newton attended the second meeting of the Westinghouse Operating Plant Owners Group in Washington.
June 19, 1979	The first Westinghouse Operating Plant Owner's Group Procedures Subcommittee meeting was held with Westinghouse in Pittsburgh. Mr. Newton is the chairman of the Subcommittee.
June 22, 1979	The Task Force issued a draft report on its review of the TMI accident for review and comment.
June 25 and 26, 1979	Additional Procedures Subcommittee and Westinghouse Operating Plant Owner's Group meetings were attended by Mr. Newton in Chicago.
June 28 and 29, 1979	Mr. Schellin attended a utility coordinator's meeting in Chicago on the EPRI-National Safety Analysis Center (NSAC) study and analysis of the TMI accident. A series of NSAC reports on TMI were obtained for Wisconsin Electric review and comment.

The Task Force activities have fallen into three major categories: development and understanding of the accident; responding to NRC bulletins, meetings and proposed modifications; and performing a careful and detailed review of the TMI events relative to the design features and operating procedures of the Point Beach Nuclear Plant. During the initial four weeks following the accident, a significant portion of the time expended by Task Force members was spent on activities associated with the first two categories. The details of the Task Force evaluation in all three categories is described in the subsequent sections of this report.

SECTION 2

THREE MILE ISLAND ACCIDENT

2.1 INTRODUCTION

In order to evaluate the effects on the Point Beach Nuclear Plant (PBNP) of a transient similar to that which occurred at the Three Mile Island Unit 2 (TMI) facility, it is first necessary to examine the events which occurred at TMI and to thoroughly understand their causes and effects on all phases of plant operation. This section examines that transient in detail and provides an autopsy of the operating control and protection systems, as well as operator actions, during the incident.

To provide the overall perspective necessary to understand the accident, a short description of the accident is given first, followed by a more detailed description. The autopsy of the accident examines plant design features, equipment failures, operator errors,and instrumentation as they contributed to the overall plant conditions. These conclusions are based on current knowledge of the event and on the TMI plant description in its Final Safety Analysis Report and other documents from Babcox and Wilcox (B&W) the reactor vendor. The time history sequence of events provides the best detailed description which could be compiled from plant (Metropolitan Edison Company), B&W, Nuclear Regulatory Commission (NRC), Electric Power Research Institute - Nuclear Safety Analysis Center (EPRI-NSAC), and Atomic Industrial Forum information. This sequence and the plant parameter transient curves are the basis for the other evaluations.

Section 3 which follows, reviews the TMI plant design; compares TMI and PBNP systems, equipment, and parameters; and evaluates a similar theoretical accident as postulated for the PBNP. Many related transients which have been analyzed for PBNP and other Westinghouse pressurized water reactors are also examined. Related events which have occurred at PBNP in the past are also re-examined relative to the TMI experience.

2.2 SHORT DESCRIPTION OF THE ACCIDENT

On March 28, 1979, at 4:00 a.m., a significant accident occurred at Unit 2 of the Three Mile Island Nuclear Plant, an 880 MWe pressurized water reactor designed by Babcock & Wilcox and operated by Metropolitan Edison Company. The summary of events described below represents a short description of the accident and is based on the more detailed description of Section 2.3.

Prior to the 4:00 a.m. start of the accident, the plant was operating normally in full automatic except for the pressurizer spray control in manual. Problems occurred in the condensate/feedwater system which resulted in the trip of the condensate pumps and then the main feedwater pumps and a turbine trip. The turbine trip transient caused a pressure increase in the reactor coolant system (RCS), with an accompanying steam relief from the pressurizer to the pressurizer relief tank. Because of the high initial power level (97%), the reactor also tripped on high pressure. This is the normal sequence of events following a loss of feed flow on this plant design. In this instance, however, the pressurizer relief valve did not properly reclose. Also, when the emergency feedwater system started, no flow reached the steam generators due to closed discharge valves. The open relief valve caused the RCS to depressurize, which actuated the high pressure safety injection system. Because there was no emergency feedwater initially, the steam generators boiled dry, removing the primary heat sink. During a period when conditions were apparently stable, one of two safety injection pumps was stopped. Continued primary coolant relief to the drain tank resulted in drain tank relief to the containment sump. Automatic actuation of the containment sump pumps discharged primary water to the auxiliary building sump tank.

When the emergency feedwater system discharge valves were opened, a partial heat sink was restored to the RCS. After parameters appeared to stabilize, the second safety injection pump was stopped. The continued pressurizer relief discharge caused the drain tank rupture disk to rupture, increasing the rate of discharge into the containment. Containment pressure increased to about 2 psig and did not cause containment isolation. Four psig is the isolation setpoint for the containment, which was prooftested to 69 psig after construction. The reactor coolant pumps in loop B were tripped and then its steam generator isolated following the tripping of the pumps in loop A. It is believed that the loop B action was due to suspected steam generator tube leaks. Both the loop A and B trips were also for reactor coolant pump protection. This resulted, however, in RCS heatup and, since the system was still depressurizing, steam which had formed in the upper reactor vessel eventually uncovered the core. Fuel damage probably occurred at this time.

The relief valve was then isolated at 6:22 a.m. and system pressure rapidly increased. Radiation alarms were triggered by the radioactivity in the water discharged into containment and pumped into the auxiliary building. A Site Emergency and then General Emergency were declared, with notification to the NRC and other civil authorities and evacuation of non-essential site personnel as planned. Subsequent attempts to control pressure using the isolation valve again uncovered the core causing additional probable fuel damage. The high pressure safety injection was also restarted automatically on low pressure. Containment pressure also increased causing isolation of the building and startup of the fan coolers. An attempt to depressurize the RCS to the decay heat removal system pressure again uncovered the core and resulted in injection into the RCS by the core flooding tanks. A containment pressure spike during the depressurization attempt actuated containment spray. This was allowed to run for six minutes. After some recovery by the RCS parameters to normal ranges, a reactor coolant pump in loop A was restarted and the plant stabilized at approximately 8:00 p.m. of the same day, March 28, 1979.

2.3 DETAILED DESCRIPTION OF THE ACCIDENT

On March 28, 1979, at 4:00 a.m., a significant accident occurred at Unit 2 of the Three Mile Island Nuclear Plant, an 800 MWe pressurized water reactor designed by Babcock & Wilcox and operated by Metropolitan Edison Company. The sequence of events, as we can reconstruct them, are described below and represent our best evaluation based on reports from the NRC, B&W, Metropolitan Edison, EPRI-NSAC, Atomic Industrial Forum, and our knowledge of similar systems.

Prior to the 4:00 a.m. start of the accident, work was being done on the condensate/feedwater system of the TMI plant. Events occurred which resulted in a trip of the condensate pumps and then the main feedwater pumps, resulting in an almost simultaneous turbine trip and a loss of water supply for the steam generators. The three emergency steam generator feed pumps automatically received a start signal and provided discharge pressure indication but no flow reached the once-through steam generators (OTSG) since the discharge valves were closed. These valves were apparently not reopened after some system tests during the two days prior to the accident. With no feedwater to the steam generators, the water that is initially in them must be relied upon to provide heat removal from the reactor coolant system.

As expected for the B&W design, upon the loss of turbine load (97% power to 0%), the pressure in the reactor coolant system increased rapidly. Within 6 seconds the electromatic relief valve opened to limit the pressure. However, since there was also a loss of feedwater, at eight seconds the pressure had increased to the reactor trip setpoint which caused the control and shutdown rods to be inserted and reduced power generation in the reactor to that of decay heat.

In the next 3 to 6 seconds, the pressure decreased to below the point at which the relief valve should have closed. It did not completely do so and thus due to continued loss of water, pressure continued a general decrease for the next 2-1/4 hours. The stored energy of the system and decay heat were removed by the water in the steam generators turning to steam and passing to the condenser via the steam dump system and venting to the atmosphere via the steam generator relief valves. This was nonradioactive steam which normally is used to drive the turbine. Most of this water was used up in the first minute.

At about two minutes into the accident, the emergency core cooling system automatically started on low pressure in the reactor coolant system. This injected high pressure, low temperature water into the reactor coolant system using two pumps. This resulted in the temperatures stabilizing and the pressure decreasing more slowly in the system. When the pressurizer level then increased and went off scale high, the operator stopped one of the high pressure injection pumps. The temperatures of the primary water loops started a slow increase and it is postulated, from the rapid pressure increase recorded, that some steam was formed in the reactor coolant system.

At eight minutes, the operator opened the emergency feedwater system discharge valves and water was immediately pumped into both OTSGs. This provided cooling for the system and the loop temperatures dropped from just under 600°F to below 550°F very rapidly. As the primary water cooled, it shrank, and taking up less volume caused the pressurizer level indication to decrease and return to an on-scale reading at this time. A decrease in pressure accompanied this volume decrease. The electromatic relief valve, which did not reclose, had been allowing steam and probably some water to dump into its relief tank as designed. As this continued, the tank pressure increased and its relief valve allowed some water to go into the containment building sump. This automatically started the sump pump at eight minutes into the accident, which discharged its water into tanks in the auxiliary building. The rate of discharge from the containment increased when the rupture disk blew out at the relief pressure setpoint for the tank protection. It is through this path that radioactive water and dissolved gases were eventually released when the auxiliary building sump tank vented and overflowed in the auxiliary building. This caused radiation alarms after about two hours (6:00 a.m.) and resulted in the operator declaring a Site Emergency shortly thereafter at 6:55 a.m.

Meanwhile, at between 20 minutes and one hour into the accident, the reactor coolant parameters had been stabilized with normal makeup established and water level in the steam generators. At one hour and 13 minutes, the operator tripped both reactor coolant pumps in the B loop and later isolated the secondary side of the B steam generator. It is believed that the isolation was based on prior tube leaks in the B steam generator, increasing level being an indication of a possible leak and belief that the accident was over or at least conditions were stable. About a half hour later, the pumps in loop A were tripped. This could have been due to the normal procedure for establishing natural circulation after shutdown or concern for pump vibration and an equipment protection action. However, since the relief valve was still open, the steam being formed in the reactor vessel stopped any natural circulation cooling. The reactor core began a heatup at this time and hot leg temperatures went off scale. Estimates are that the core may have been almost half uncovered (7 feet of water and 5 feet of steam) for up to an hour. This is the point (6:00 a.m.) when the first radiation alarms sounded. At 6:22 a.m. the open relief valve had been discovered and was isolated.

Reactor coolant system pressurizer pressure increased along with pressurizer level. In an attempt to control the pressure (or high level), the isolation valve was cycled open and closed as needed. This resulted in more steam/water relief to the relief drain tank and containment. When containment pressure reached the 4 psig setpoint, all penetrations were isolated. Pressure peaked at 4.5 psig and fan coolers were started. The reactor coolant system pressure also dropped enough during this period that the high pressure safety injection system restarted. High activity in the containment was noted at 7:24 a.m. and a General Emergency was called and the NRC and other offsite authorities were notified. It is estimated that the core was again uncovered for about a two-hour period to about the same levels as before.

The isolation valve was again closed and when pressure increased, the core substantially recovered. This lasted for two hours and then an attempt was made to depressurize the system and initiate the decay heat cooling system. The core again uncovered and pressure got low enough that the core flooding tanks partially discharged their water into the system. A spike in containment pressure actuated the containment spray system, which was allowed to run for six minutes. The primary system was then repressurized when its pressure could not be dropped low enough to initiate the decay heat cooling system. During the flooding tank injection, the hot leg temperatures decreased and returned to an on-scale reading along with pressurizer level. This indicates that the water added to the system may have refilled the primary system and condensed any steam establishing some natural circulation. One pump was restarted in the A loop and steam flow to the condenser began. This allowed the reactor system to be stabilized and cooled which essentially ended the accident after approximately 16 hours.

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2.4 AUTOPSY OF THE ACCIDENT

The following items are events, equipment failures, design features, operator or plant personnel actions due to an operation performed or not performed, or instrumentation indication (lacking, incomplete, or misleading) which contributed to the overall accident at TMI. They are listed in their chronological order of occurrence or time of effect on the accident. Included in each item is a descriptive title, operator action requirements, an evaluation or estimate of the major cause(s) of the item, and a best estimate description. Operator is used to indicate the decisions or actions of one or more licensed plant personnel normally assigned to operate the plant from the control room. Plant personnel is used to indicate other persons working in the plant including supervisors, other company management and consultants (B&W, NRC). Decisions or actions of this group may have been carried out by an operator or operators.

A. Initiating Event

A Loss of Feedwater accident is considered in the plant design. Operator action is to follow procedures and verify safety and control system responses. The initiating cause of the TMI accident was loss of main feedwater. This was probably due to the automatic tripping of the condensate or condensate booster pumps since net positive suction head is reduced or lost to the main feedwater pumps when the condensate pumps trip. Continued operation under these conditions could result in feedwater pump damage. This sequence has been attributed variously to personnel working on the system, high ΔP on the full flow condensate polishing system or closing of a condensate polishing system valve in response to moisture in its control air.

B. Turbine Trip - Reactor Trip Sequence

The operator has to verify the turbine trip. In the B&W design, reactor trip is not automatic for a turbine trip. When the turbine tripped on loss of main feedwater, no reactor trip occurred, which allowed continued full power production (8 full power seconds = 2.12×10^7 Btu) until some direct reactor trip setpoint was reached in the RCS. The reactor tripped $\sim$8 seconds after the turbine trip on high pressurizer pressure. The loss of feedwater accident analysis for TMI assumed a reactor trip at 13.4 seconds.

C. Pressurizer Relief Valve Response

It can be expected that the relief valve will open on a large loss of load for the B&W design. On the load rejection from 97% power, the Electromatic Relief Valve (EMOV) opened at its 2255 psig setpoint resulting in the establishment of an RCS depressurization path. This is the normal response for loss of load. Pressure was limited to about the reactor trip setpoint (2355 psig) even though the TMI loss of feedwater accident analysis calculated a maximum RCS pressure of 2500 psig. The Wide Range RCS Pressure strip chart indicated a peak pressure of 2435 psig which suggests that one or both safety valves may have lifted. This is not confirmed by the Narrow Range RCS Pressure recorded trace.

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D. Auxiliary Feedwater System Response

The auxiliary (emergency) feedwater system pumps were actuated and up to operating pressure within the 40 seconds considered in the loss of feedwater accident analysis. The discharge valves were, however, closed due to plant personnel not reopening them after a system test sometime in the two days just prior to the accident. Neither operators nor plant personnel after that time recognized the problem. This was a violation of the Technical Specifications. A verification of valve position or system flow should have recognized this immediately in the accident sequence. This did not occur until approximately 8 minutes into the accident. The operator then opened the valves and established the auxiliary feedwater flow to the secondary side of the OTSGs. A weekly board check for valve alignment was scheduled for the afternoon of the day of the accident.

E. Pressurizer Relief Valve Closure

The EMOV partial closure or non-closure was likely due to equipment failure. After normally opening, the EMOV did not reclose completely or reseat properly after the close setpoint of 2205 psig was reached on the downward pressure transient. This established a path for system depressurization below operational limits.

F. Pressurizer Relief Valve Indication

The EMOV indication of closure was erroneous or misleading and not verified by the operator through other indications. Indication of the EMOV position is not directly displayed but the supply of electrical power to the solenoid is indicated. Thus, a signal to deenergize the EMOV results in an indication on the control board of "closed" when, in fact, the valve may not be closed. The operator, thus, may have believed this indication which was in error. Later in the transient, an operator was able to recognize or somehow determine that the EMOV was open and closed the block valve. The EMOV discharge pipe temperature indication was apparently not considered.

G. Steam Generator Inventory Depletion

The small design inventory of secondary water in the steam generators was depleted quickly. Loss of heat removal from the RCS resulted in heatup which the operator should have recognized from OTSG instrumentation. Due to the OTSG inventory of water at full power being relatively small, not having auxiliary feedwater resulted in a rapid dryout of the OTSG with little heat removal and rapid RCS heatup. OTSG pressure, temperature, and level indications were available to the operators.

H. High Pressurizer Level Indication

The pressurizer level was apparently misleading to the operator since both heatup and depressurization were in progress. Pressurizer level does not indicate RCS mass inventory loss when there is a simultaneous volume expansion due to increasing temperature (decreasing heat removal).

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The heatup yielded a high pressurizer level indication while the reduction in RCS inventory was in progress. This misled the operator and apparently the operator did not cross-check with other instrumentation which could indicate a loss of water inventory. Many subsequent decisions appear to be based on this high pressurizer level indication.

I. Termination of High Pressure Safety Injection

The operator prematurely stopped HPSI. This was probably based on high pressurizer level indication. The operator shut off first one and then the other high pressure safety injection pump. This stopped the only source of RCS cooling water and the major source of heat removal. The decision to terminate the high pressure safety injection should have been based on level, temperature, and pressure indications considered together. These would have enabled the operator to determine the actual RCS conditions.

J. RCS Pressure Drop and Void Formation

Apparently plant personnel continued to rely principally if not solely on pressurizer level. They did not recognize that the drop in RCS pressure during the heatup might result in void formation. Apparently no correlation was made between instrument indications of pressure and temperature to determine if saturated conditions existed.

K. Reactor Coolant Drain (Pressurizer Relief) Tank Indication

The plant personnel failed to recognize the continued EMOV relief. Plant personnel also did not recognize the pressure and temperature increase of the reactor coolant drain (pressurizer relief) tank (RCDT) resulting from the continued relief of the EMOV.

L. Pressurizer Relief Valve Isolation

The EMOV was not isolated by the operator in a timely manner. This allowed continued RCS water loss and decrease in pressure.

M. Rupture Disk Relief

The relief tank rupture disk failure is designed to protect the tank. Rupture and tank relief did not result in any operator action. The failure of the rupture disk as protection for the RCDT caused RCS water (steam) release to containment. This release was not recognized by the operator. Drain tank instrumentation indications are on the back of a side panel and not readily accessible to the operator. The rupture disk failure and release to containment was further indication of the EMOV staying open and should have resulted in its isolation.

N. Start of Containment Sump Pumping

The containment sump pump automatically started to pump water from containment to the full auxiliary building sump tank. This provided a path for contaminated water and dissolved gases to get outside the

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containment. The sump pump at TMI is designed to start automatically when the water level rises above 38 inches. The operator apparently did not recognize the continued pump operation, the source of water, or amount pumped. The operator could have stopped the sump pumps.

O. Containment Isolation Signal

TMI containment isolation is based only on containment pressure and did not isolate on the safety injection (SI) signal. The containment isolation setpoint is 4 psig which does not anticipate releases which maintain lower pressures. The small break condition (open EMOV) which caused releases to the containment via the RCDT rupture disk did not result in isolation until over four hours had elapsed. The operator could have manually isolated containment.

P. Pressurizer Surge Line Layout

The RCS and pressurizer are arranged such that the surge line forms a loop seal between the two water volumes. This resulted in a pressurizer level indication such that the RCS appeared full when it was partially voided.

Q. Reactor Coolant Pump Stoppage - Loop Isolation

The operator first shut off the two loop B reactor coolant pumps, next the two loop A pumps, and then isolated the secondary side of the B loop to reduce potential releases, because of suspected OTSG tube leaks. The initial operator action stopping the pumps was probably a protective action, due to pump vibration concerns.

R. Establishing Natural Circulation

While attempting to establish natural circulation, verification of continued cooling of the core is necessary. The plant personnel apparently failed to recognize the large hot leg heatup and cold leg drop in temperature after the pump trip. This showed that natural circulation cooling was not established.

S. Primary Loop Layout - Hot Leg

The elevated hot leg outside the steam generator resulted in steam binding and failure of natural circulation. Due to the vessel, hot leg, OTSG, pump and cold leg layout, and void in the vessel which is carried into the hot leg will - during low circulation flow levels - end up trapped in the hot leg above and outside the OTSG. This cannot be condensed by the secondary system heat removal and blocks loop circulation.

T. Primary Loop Layout - Cold Leg

In the TMI loop design, steam which is condensed in the steam generator does not return directly to the vessel via gravity. A large portion of the OTSG and the vertical portion of the pipe from the OTSG to the pump suction are below the vessel inlet nozzle. The cooled water is trapped in this loop and maintains a static head which blocks natural circulation flow from the OTSG to the vessel.

U. Repressurization and Pressurizer Response

Pressurizer drainage to the RCS was blocked by the surge line loop seal. The closing of the EMOV and repressurization of the RCS (to some degree) did not result in draining of the pressurizer. The plant personnel apparently believed that the RCS had sufficient water level and volume when it was, in fact, partially voided and decreasing in inventory.

V. Pressure Control With Relief Isolation Valve

Plant personnel attempts to control RCS pressure using the EMOV block valve caused void formation in the core. Several attempts to depressurize the RCS, using the EMOV block valve without regard for system temperature, resulted in further uncovering of the core, Zr-H_2O reaction, and fuel damage. This depressurization also reinitiated safety injection.

W. Attempt to Institute Decay Heat Cooling (Residual Heat Removal) System

The RCS depressurization was initiated, apparently without regard for temperature. The attempt to put the Residual Heat Removal (RHR) system into service resulted in additional core voiding and damage. A lack of understanding of conditions requiring core cooling, RCS makeup, or emergency systems actuation seemed to exist. The relief capacity design is large enough to depressurize the RCS below saturation but not below the point of institution of RHR for the conditions of substantial heat being produced and the RCS inventory decreasing.

2.5 TIME HISTORY SEQUENCE OF EVENTS

TIME	DESCRIPTION
March 28, 1979	Before 4:00 a.m., a TMI operator was working on the Feedwater System.
4:00 a.m. = 0	Lost condensate (-1 sec), then feedwater pumps, due to full flow demineralizer problems or air operated valves closing. Almost simultaneously (<1 sec), the turbine trip occurs. [TMI has two 50% turbine driven main feed pumps. The three Emergency Steam Generator Feed pumps (two-50% motor and one-100% turbine driven) receive a start signal upon trip of the main feed pumps].
3-6 sec.	Pressurizer pressure increases to the Electromatic Relief Valve (EMOV - the only power operated relief valve on the TMI pressurizer) setpoint of 2255 psig and it opened as designed. The reactor was still at power (97%).
8 sec.	Reactor trips on high pressure at 2355 psig (T_{SAT} = 659.3°F) at the hot leg tap. Pressurizer heater banks 1-5 tripped (5 total banks made up of 13 individual groups of heaters) and returned to normal six seconds later. Spray control was reset from manual continuous flow to Auto.
9 sec.	Secondary side pressure peaks at 1070 psig and is limited by steam relief valves and steam dump to the condenser. Relief (2) and safety (8) valve settings: 4 - 1050 psig (22 psi line ΔP to the valves implies 2 - 1065 psig only the reliefs lifted: 1050 + 22 = 2 - 1075 psig 1072 psig at OTSG) 2 - 1102 psig
14 sec.	Indications from pump discharge pressure are that the ESGF pumps are all running at this point; however, no level change occurs in the Once Through Steam Generators (OTSG). Discharge valves were closed.
15 sec.	Pressurizer level peaks at 255 inches (of a total range of 400 inches indicated) and starts to decrease with system contraction. RCS pressure at approximately 2200 psig (T_{SAT} = 651°F) and, at this time, the EMOV should have closed (2205 psig setpoint). TMI has solenoid indication and not true valve position on the board.
30 sec.	Reactor Coolant Drain Tank (RCDT - the quench tank for the pressurizer) pressure is increasing.

TIME	DESCRIPTION
54 sec.	Pressurizer level is at a minimum of 158 inches and starts to increase. Hot leg temperature is at a minimum of 577°F and starts to increase.
1 min.	Pressurizer pressure decreasing rapidly. OTSG level indications stop their rapid drop and level off at 10 inches (indicated) on the startup range instrumentation with OTSG pressure holding at about 1025 psig.
2 min. 4 sec.	The Emergency Core Cooling System (ECCS) high pressure safety injection pumps (HPSI) actuated automatically at 1600 psi (T_{SAT} = 606°F) RCS pressure.
3 min.	RCDT pressure reaches and then stabilizes at 120 psig and maintains this value through 5-1/2 minutes (relief valve setpoint is 150 psig). Pressure exhibits oscillatory behavior that would be expected if the relief valve had actuated.
3-8 min.	OTSG pressure decreases to below 750 psig as the secondary side level remains low and it dries out.
4 min. 38 sec.	One HPSI pump (1C) was manually shut off. HPSI Pump 1A running throttled. Hot and cold leg temperatures start to increase at a more rapid rate.
5 min. 10 sec.	Pressurizer level (increasing since 54 sec.) reaches a maximum at 375 inches (indicated) and hesitates there for about 10 sec. (drops 5 in.) before increasing again.
5 min. 30 sec.	Two phase flow (water relief) through EMOV.RCDT pressure shows a rapid increase.
6 min.	RCS pressure has decreased steadily and reaches a minimum of 1350 psig (T_{SAT} = 584°F). Since Thot is increasing, this causes flashing in the RCS. This is supported by an increase in RCS pressure, pressurizer level, and RCDT pressure all beginning at this time. RCDT pressure reaches a peak of 155 psig just after 6 min. and relief valve (150 psig setpoint) limits pressure. Pressurizer level goes off scale high.
7 min. 43 sec.	Reactor building sump pump came on automatically discharging water into the full auxiliary building sump tank, which also had a previously blown rupture disk.
~8 min.	Operator opened the discharge valves and, thus, auxiliary (emergency) feedwater (EFW) flow is established to both OTSGs. This is indicated by immediate OTSG repressurization to 1000 psig and slight level increase.

TIME	DESCRIPTION
8 min. 30 sec.	RCS hot leg temperatures (which were holding at 572 to 578°F) have increased to peaks of 593 to 597°F, for loops B and A, respectively. It is postulated that almost all feedwater is, therefore, turned to steam causing no level change but rapid heat removal from the primary system. Both RCS T_{HOT} and T_{COLD} indications begin rapid decrease from this peak. The RCS pressure peaks at 1500 psig (T_{SAT} = 596°F) and begins a decrease as T_{HOT} drops below saturation.
10 min.	Pressurizer level indication returns on scale and fluctuates around 375 inches (indicated) thru at least 30 minutes.
10 min. 19 sec.	Second reactor building sump pump starts. Total flow now 280 gpm (140 gpm capacity of each pump).
10 min. 24 sec.	Makeup pump 1A trips and is restarted within 3 sec. It trips again in 1 sec.
10 min. 48 sec.	Reactor building high sump alarm (setpoint 4.65 ft). The Control Room Operator reported that the sump overflowed (6 ft.) sometime after this point.
~11 min. 30 sec.	RCDT has decreased to about 122 psig probably due to RCS shrink and turns upward again as HPSI shut off completely.
11 min. 40 sec.	Makeup pump 1A restarted, trips, and restarted by operator to control pressurizer level. After this restart, pump 1A remained in the throttled condition until the second HPSI initiation at 3 hrs. 23 min. 16 sec.
**** NOTE ****	Indications on the pressurizer level and auxiliary feedwater established may have misled the operators into thinking the accident was under control. It is postulated that the HPSI pump was thus restored to normal makeup service at this time. RCS pressure did recover temporarily with auxiliary feedwater and one HPSI pump running.
15 min.	RCDT pressure reaches 192 psig and rupture disk blows, causing rapid drop to 10 psig in 36 sec. RCS at 1275 psig and cold leg temperature of 567°F (PSAT = 1185 psig).

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TIME	DESCRIPTION
18-30 min.	Decreasing RCS pressure stabilizes at about 1015 psig (T_{SAT} = 550°F) and coolant average temperature of 550°F and a pressurizer level of 380-395 inches (400 full scale).
20-28 min.	The RCS temperature stabilizes at a hot leg of 553°F and a cold leg of 548°F. The temperature decrease from start of auxiliary feedwater to this stabilization represents a 200°F/hr cooldown. Reactor building pressure is 1.4 psig and increasing. Two foot startup range level is restored in both OTSGs.
20-40 min.	Steam driven emergency feedwater pump shut off. Efforts to start main feedwater pumps in progress.
32 min. 30 sec.	Incore thermocouple (10-R) indicates offscale.
36 min.	EFW pump "B" turned off.
38 min.	Reactor building sump pumps turned off by Auxiliary Operator, after operating for 28 and 31 minutes and pumping ∿8,260 gallons of water to the Auxiliary Building. Discharge line not isolated so additional flow may have occurred later.
50 min.	The startup level indication shows OTSG B level <u>increasing</u> and OTSG A level <u>decreasing</u>. Pressure increases in both OTSGs. This could support the belief that a tube leak existed in OTSG B.
(5:00 a.m.) 1 hr.	During the 22-60 minute period, the system parameters have stabilized at the saturation condition of a pressure of ∿1015 psig, reactor outlet hot leg temperature of ∿550°F [P_{SAT} = 1030 psi]. RCS flow indication is decreasing from 60 (initial) to 50 x 10^6 lb/hr per loop. RCP vibration alarms received. The reactor building pressure is 2.2 psig and increasing.
1 hr. 13 min. 29 sec. 1 hr. 13 min. 42 sec.	Two reactor coolant pumps are tripped in Loop B. Reactor coolant flow of 40 x 10^6 lb/hr drops to zero in Loop B. TMI operators stopped the pumps in Loop B first to maintain pressurizer spray capability which comes from Loop A. Operators reportedly recognized they were violating RCP pressure-temperature limits. OTSG B pressure drops, due to loss of heat input, from 950 psig to 140 psig in the next 18 minutes.
1 hr. 20 min.	Factor of 10 increase in radiation level as shown on letdown line monitor.

TIME	DESCRIPTION
1 hr. 30 min.	T_{HOT} follows T_{SAT}. ΔT across the core in Loop A equals about 500°F. RCS pressure starts to drop rapidly. High radiation readings in Hot Machine Shop.
1 hr. 40 min. 37 sec. 1 hr. 40 min. 45 sec.	Both remaining RC pumps are tripped in Loop A. Reactor coolant flow of 27 x 10^6 lb/hr drops to zero in Loop A. [We assume the pumps were secured due to reduction in the net positive suction head or vibration concerns. The decreasing flows indicate pumping of a two-phase mixture.]
1 hr. 42 min.	Operator isolates OTSG B from secondary system.
1-3/4 hr.	T_{HOT} and T_{COLD} diverge rapidly. T_{HOT} >620°F offscale in less than 15 minutes. T_{COLD} drops to about 200°F at 5 hours. Pressurizer level continues to drop to below 300 inches and pressure follows to below 700 psig.
2 hr.	T_{HOT} offscale high. Radiation alarms sound.
2 hr. 22 min.	EMOV isolated for first time by block valve. RCS pressure reached a low value of 600 psig at this point (T_{SAT} = 498°F). Core would have steam cooling and superheating in upper elevations. Estimate by B&W that the core was uncovered 5 ft. for one hour (5:45 to 6:45 a.m.), then recovered to 11 ft. [It is understood that new personnel were in the control room from the next shift and affected the EMOV isolation.]
(~6:55 a.m.) 2 hr. 55 min.	Site Emergency announced.
2 hr. 54 min.	Reactor coolant pump 2B started and ran for 19 min. since operators were unsure about establishing natural circulation. Groups 1-5 of the pressurizer heaters trip and remain tripped for 1-1/2 hours. This is a continuing problem during the incident.
3 hr. 11 min.	EFW pump 2A tripped by the operator.
3 hr. 13 min.	RCS pressure peaks at 2150 psig and starts rapid decrease when EMOV is unblocked to control pressure. RCDT pressure spike of 5 psi at this time.
3 hr. 15 min.	Control and Service Building evacuated (not the Control Room).
3 hr. 20 min. 13 sec.	Makeup pump 1C started (1B has been off since HPSI initiation at 2 min.).
3 hr. 23 min. 16 sec.	HPSI comes on at 1600 psig setpoint.

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TIME	DESCRIPTION
(~7:24 a.m.) 3 hr. 23 min. 23 sec.	General Emergency called due to high activity in containment.
3 hr. 30 min.	RCS pressure oscillates for about one hour (1480-1560-1450-1750-1480-1550 psig). Containment pressure in the range of 1 to 2 psig decreasing slightly. [We assume fluctuations here due to operation of the block valve and releases of water, steam and non-condensible gases.]
3 hr. 35 min.	EFW pump 2A running.
3 hr. 37 min.	HPSI pump 1C to loop A turned off. RCS pressure decreases stepwise and containment pressure increases stepwise - 1 to 3 psig by 4 hr. HPSI pump 1A is still running.
3 hr. 45 min.	B&W estimates that the core was again uncovered 5 ft. for two hours (7:45 to 9:45 a.m.) then recovered to 10.5 ft.
3 hr. 48 min.	RCDT indicates a pressure spike of 11 psig.
3 hr. 56 min.	Makeup pump 1C started.
4 hr. 17 min. 17 sec.	Makeup pump 1A tripped. Restart attempted at 4 hr. 18 min. 30 sec. Pump trips in 3 seconds and remained off throughout this sequence. Makeup pump 1B was, therefore, started at 4 hr. 22 min.
4 hr. 17 min. 22 sec.	Makeup pump 1C tripped. No makeup pumps operating for 4-1/2 minutes. This pump was restarted at 4 hr. 27 min. and remained operating until 9 hr. 4 min.
4 hr. 17 min. 30 sec.	Containment pressure reaches containment isolation setpoint of 4 psig. Building fan cooler comes on. 4.5 psig peak reached. RCS pressure varying in the range 1250 to 1380 psig until 5-1/2 hr. Level restored to ~380 inches at ~4 hrs.
4 hr. 20 min.	Containment dome radiation monitor exceeds 600 R/hr and reads 1000 R/hr 20 min. later and 600 R/hr at 5 hr.
5-6 hr.	RCS pressure increases rapidly from 1250 to 2120 psig in 35 minutes. The EMOV block valve is closed, one HPSI pump (1A) is on. No more than 10 of 13 pressurizer heater groups now operational. Reactor Building Air Cooler B started during this time.
6 hr. 10 min. +	Airborne levels in Unit 2 Control Room require evacuation of all but essential personnel. It is reported that Unit 2 people had to don masks at 6 hr. 17 min. and not many people had left the control room as a result of the evacuation order (20+ people at 6 hr. 55 min.).

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TIME	DESCRIPTION
6-7 hr.	OTSG A level is ramped up from 50% to 95% on operating range in one hour and to 100% in 1.5 hours. OTSG A pressure starts to decrease toward zero from about 100 psig. OTSG B at 200 psig.
7 hr. 30 min.	The EMOV block valve is opened in an attempt to depressurize to 400 psig and initiate the Decay Heat Cooling System. RCS pressure starts to decrease (2050 psig to 480 psig in 1 hr. 45 min.). [900 psig/hr or 15 psi/min. rate.] No more than 7 pressurizer heater groups operable.
8 hr. 41 min.	RC system pressure reaches 600 psig, core flood tank setpoint. These passive accumulators partially discharge to 450 psig.
9 hr.	B&W estimates the core again uncovered 7.5 ft. for an unspecified time. RCS pressure recovered several hours later.
9 hr. 50 min.	Containment pressure spike to 28 psig occurs due to a hydrogen burn (low grade explosion). Containment spray actuated and sprays 5000 gallons of sodium hydroxide ($NaOH$) solution into containment. $NaOH$ tank not quite 1/2 empty after six minutes of operation before stopped by the operator. No more than six pressurizer heater groups operable.
10 hr. 30 min.	T_{HOT} Loop A reappears on scale, decreases to 525°F in 1/2 hour. Makeup pump 1C restarted twice; 1B and 1C now operating but 1C operates only $\sim$4 min. total.
11 hr.	The pressurizer level decreases rapidly and then returns which may indicate a large steam bubble collapse in the RCS.
11 hr. 18 min.	T_{COLD} Loop A increases in about 5 minutes from 150°F to 250°F. This indicates some flow in the OTSG.
12 hr. 30 min.	HPSI flow increases to 400 gpm. T_{HOT} in Loop A decreases.
13 hr. 48 min.	Reactor coolant pump 1A is started and hot leg temperature decreases to 560°F while cold leg temperature increases to 400°F.
Thereafter	Condenser vacuum re-established. OTSG A begins steaming to condenser at $\sim$16 hrs. RCS cooled to approximately 300°F, 100 psi. Letdown line ceased to permit flow and relief valve (pressurizer vent) being used (estimated 14-16 gpm flow). Some fuel incore thermocouples reading about 600°F. Containment pressure below 1 psi. High radiation in reactor containment and auxiliary building. Makeup pump 1C intermittently on and off.

2.6 PLANT PARAMETER TRANSIENT CURVES

The following figures are curves of the major TMI plant parameters versus time during the accident. These figures were selected for presentation in this report because they show the most significant information with regard to the reactor coolant system conditions, safeguards system operation, and status of equipment via instrumentation indications available to the TMI operators. The operator actions assumed in various sections of this have been deduced from these curves and other supplemental information.

The following is a list of the figures included herein:

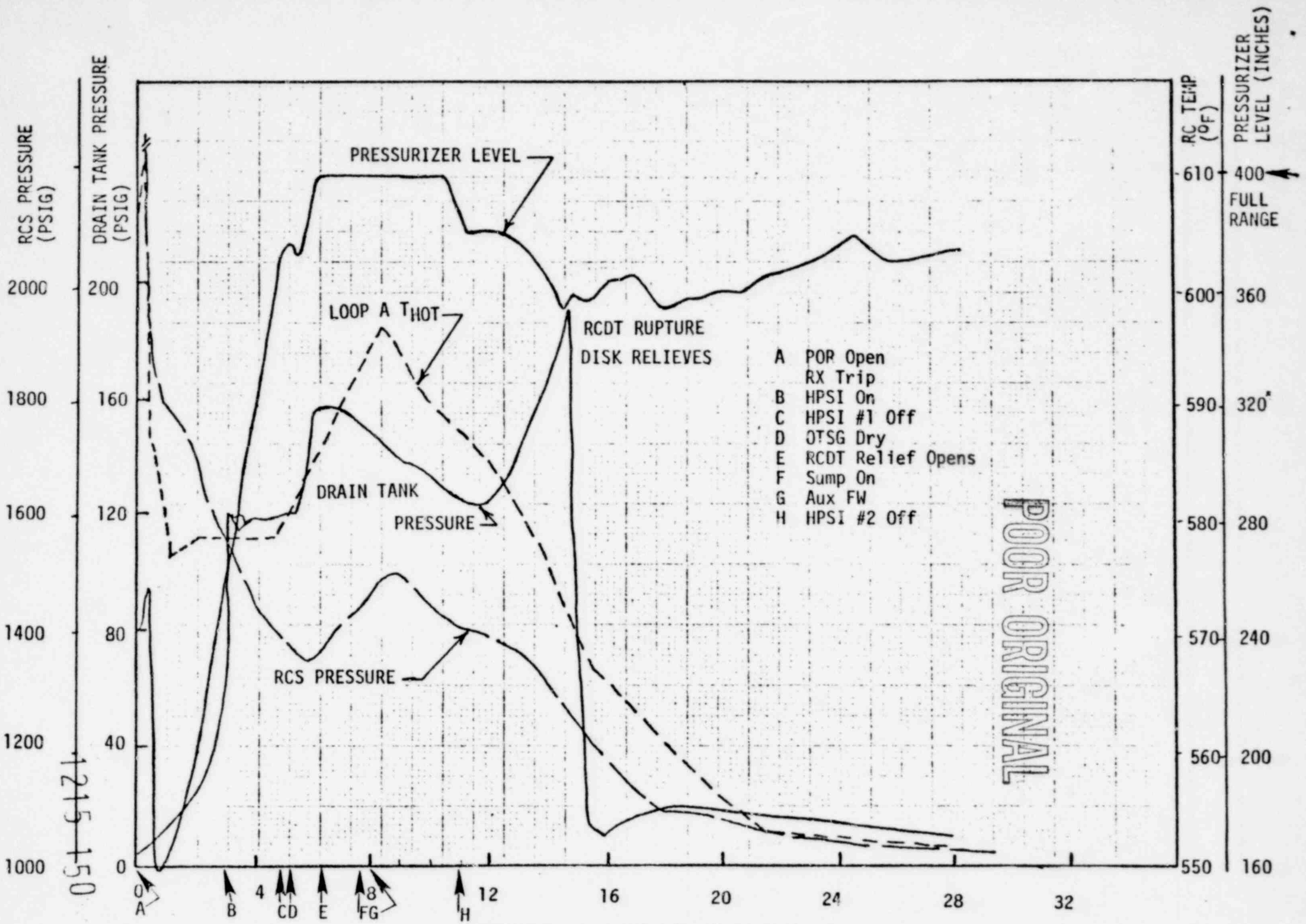


FIGURE 2.6-1 RCS PRESSURE AND TEMPERATURE, DRAIN TANK PRESSURE, AND PRESSURIZER LEVEL FROM 0 TO 28 MINUTES.

1215 150

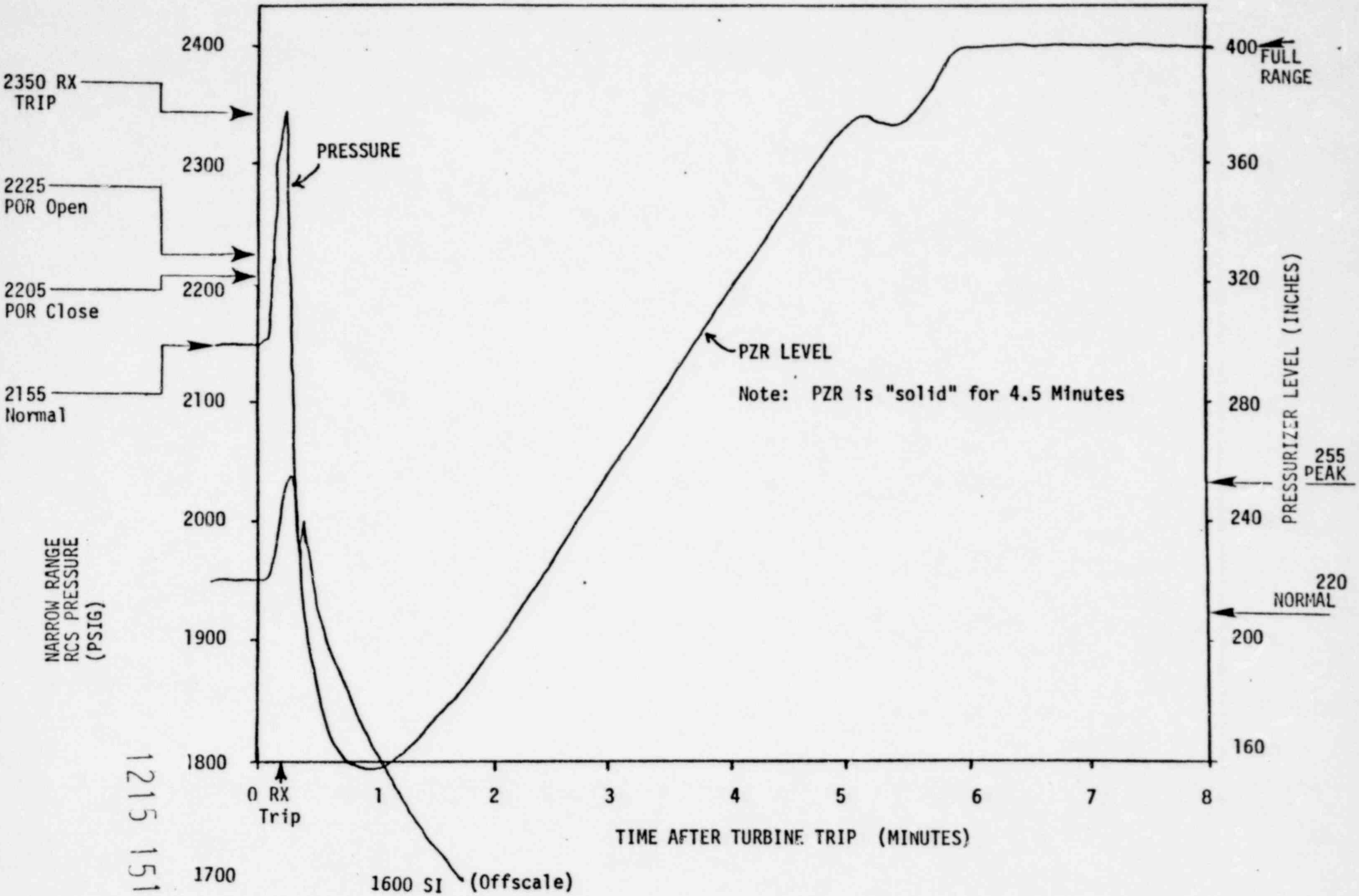


FIGURE 2.6-2 PRESSURIZER PRESSURE AND LEVEL FROM 0 TO 28 MINUTES

1215 151

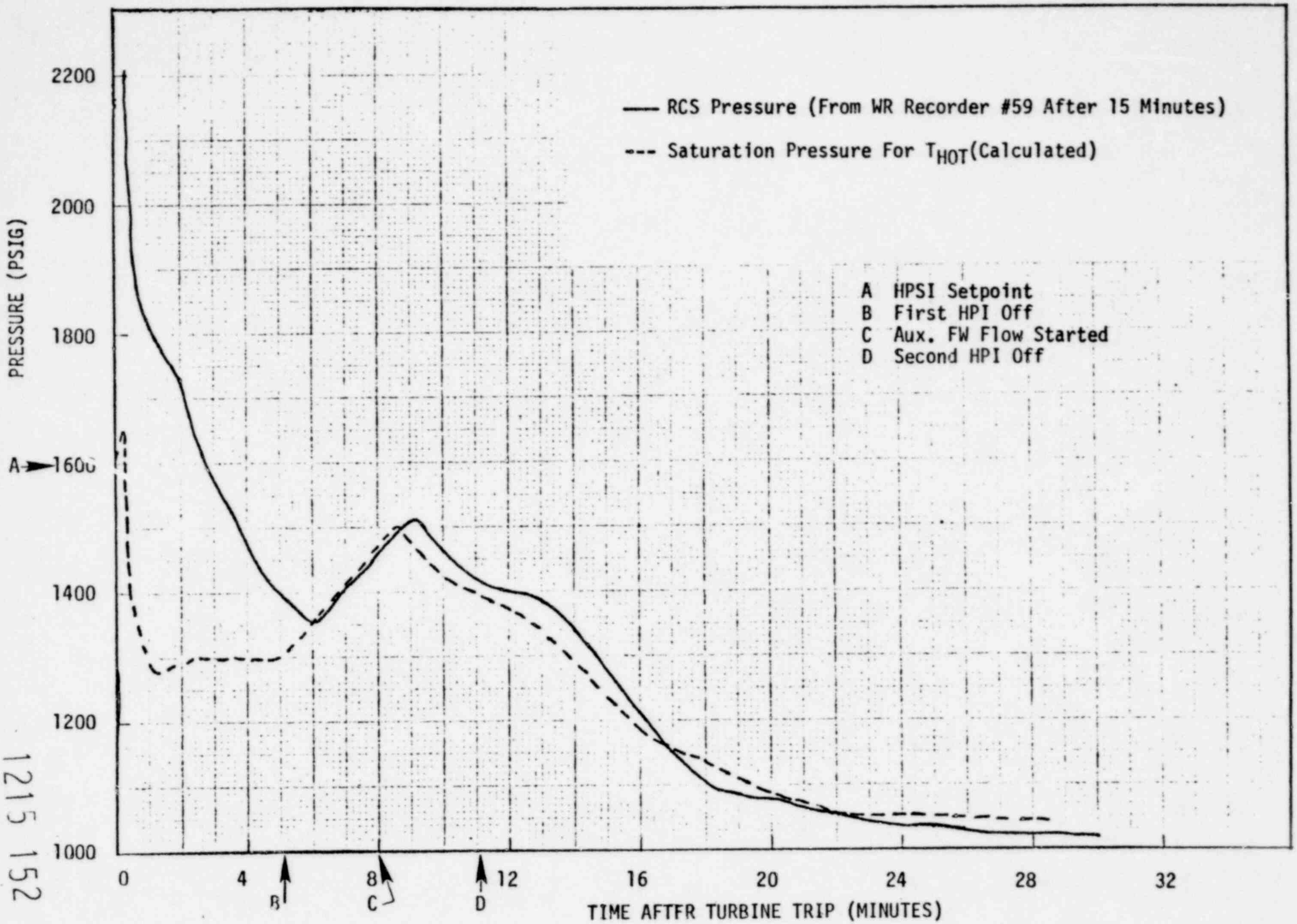


FIGURE 2.6-3 RCS PRESSURE COMPARED TO SATURATION PRESSURE FOR T_{HOT} FROM 0 TO 28 MINUTES

1215 152

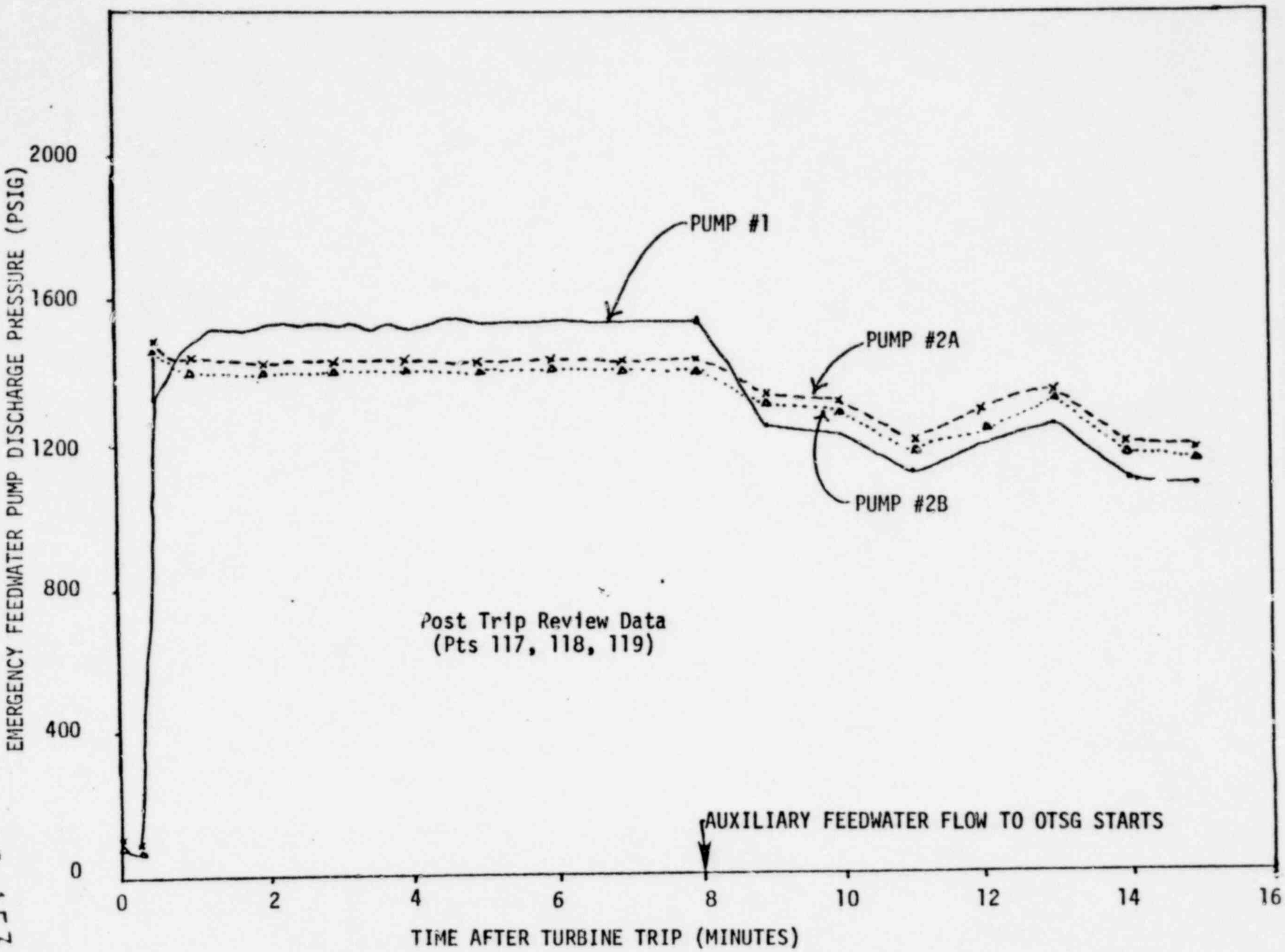
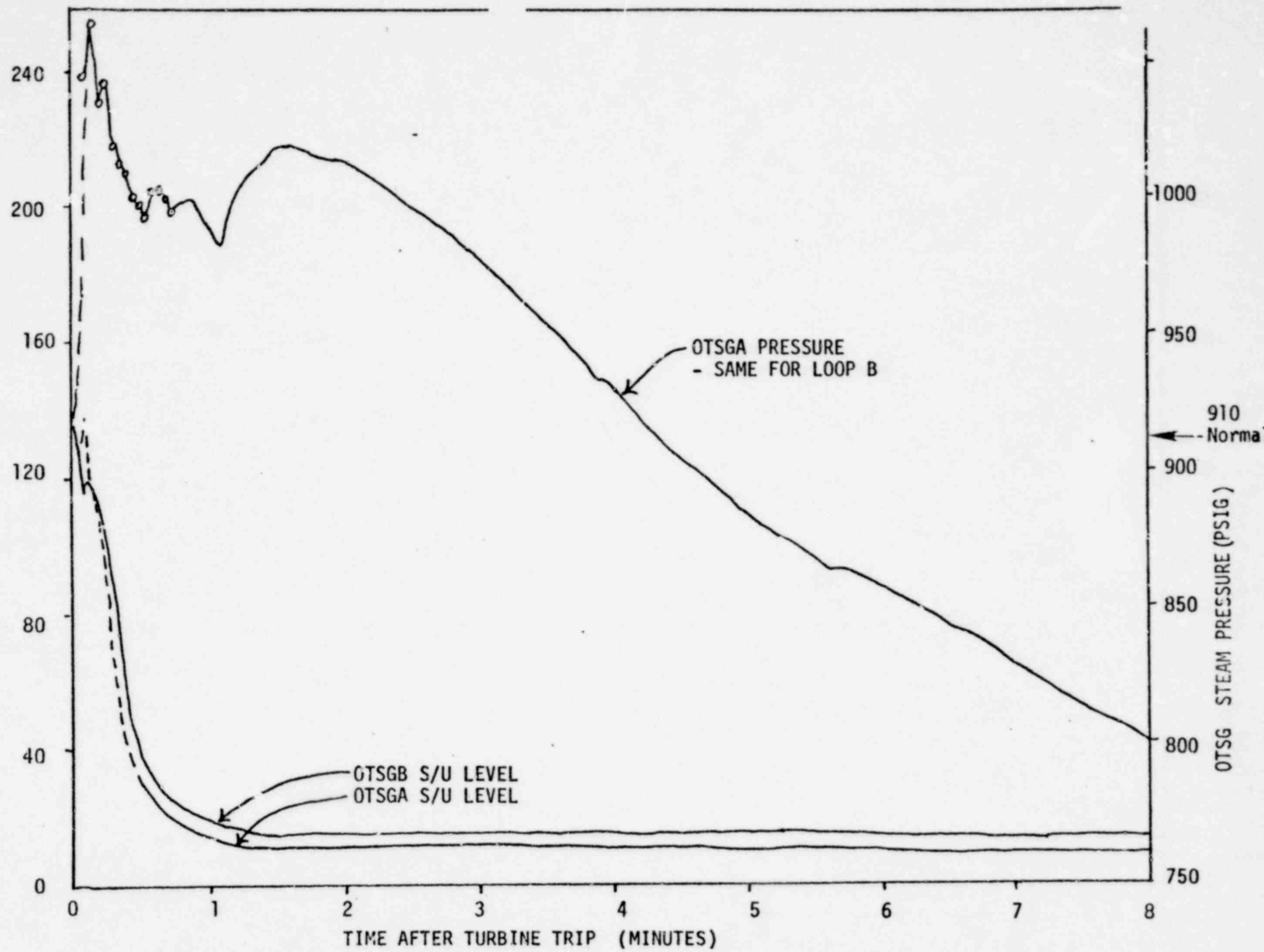


FIGURE 2.6-4 EMERGENCY FEEDWATER PUMP DISCHARGE PRESSURE FROM 0 TO 15 MINUTES

1215 153



1215 154

FIGURE 2.6-5 OTSG STARTUP LEVELS AND STEAM PRESSURES FROM 0 TO 8 MINUTES.

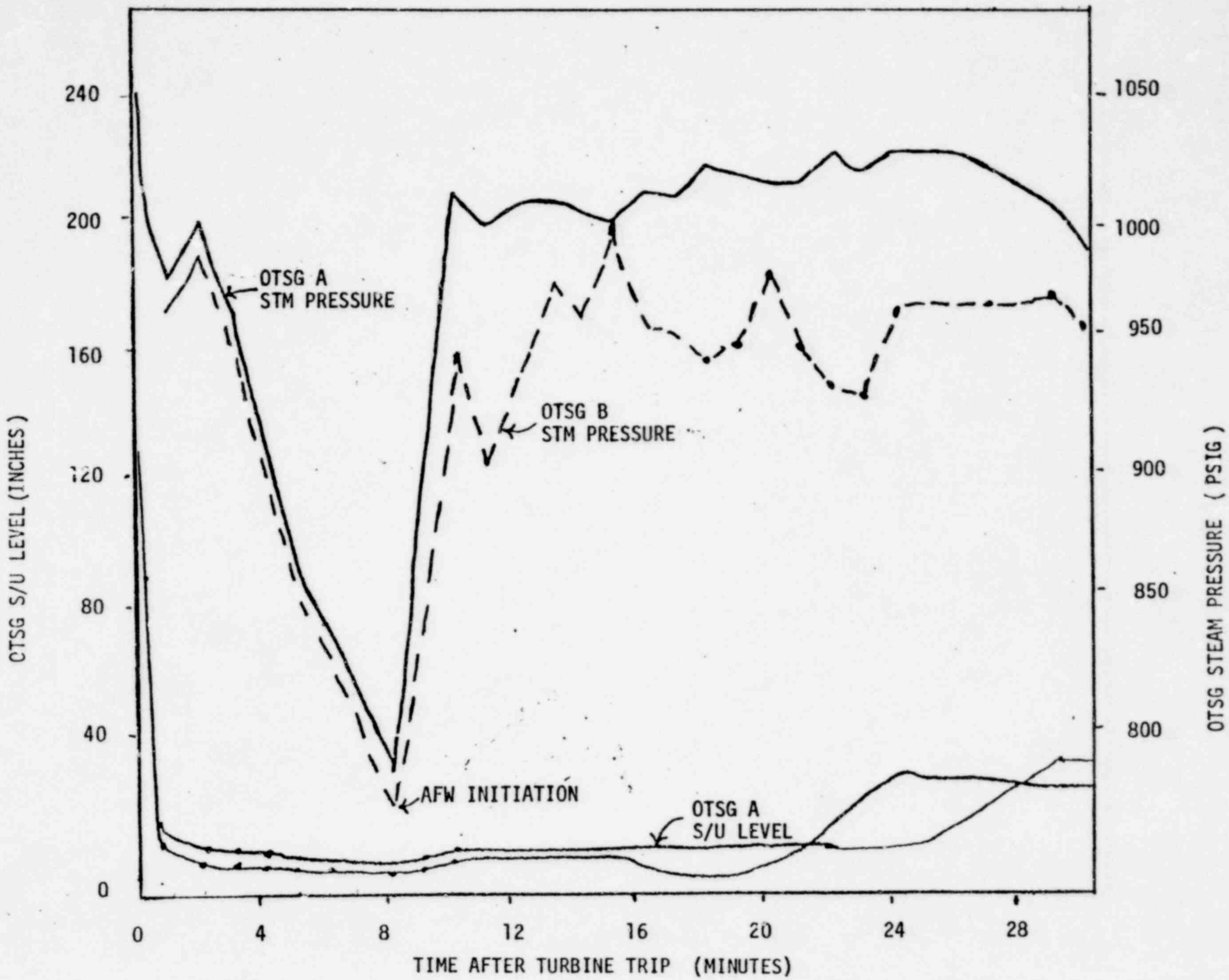


FIGURE 2.6-6 OTSG STARTUP LEVELS AND STEAM PRESSURES FROM 0 TO 30 MINUTES

1215 155

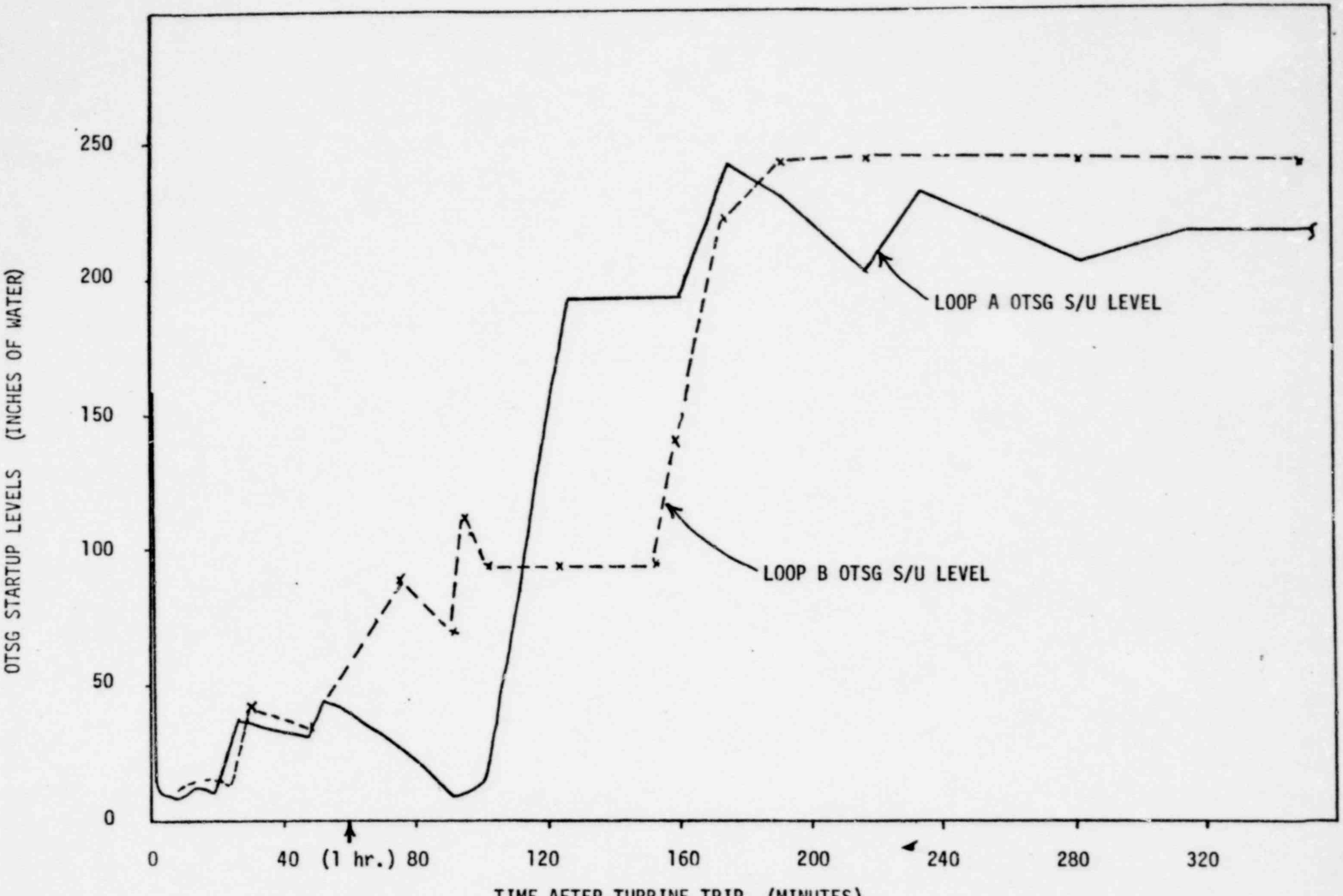


FIGURE 2.6-7 OTSG STARTUP LEVELS FROM 0 TO '30 MINUTES

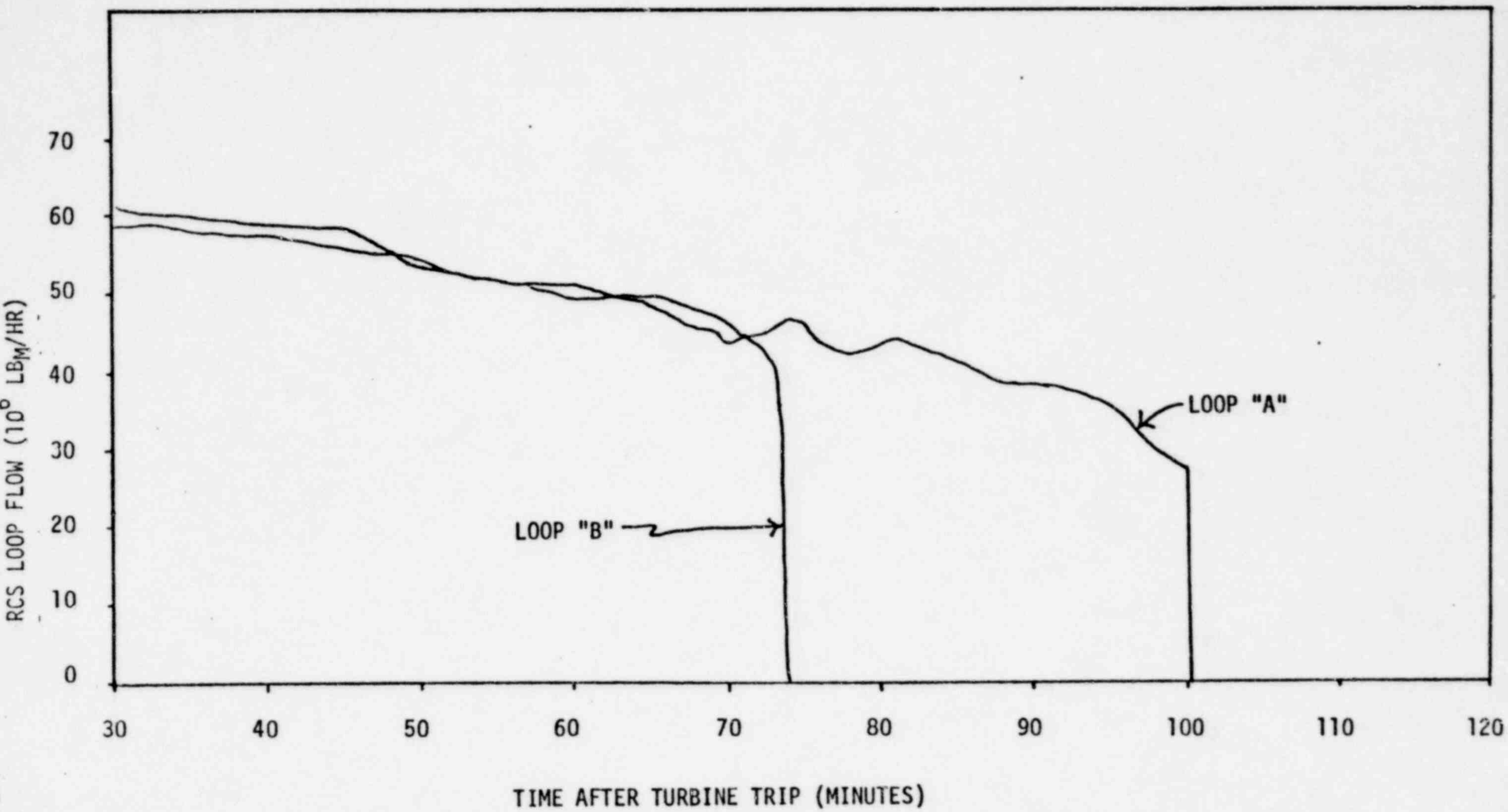


FIGURE 2.6-8 REACTOR COOLANT FLOW FROM 30 TO 120 MINUTES

1215 157

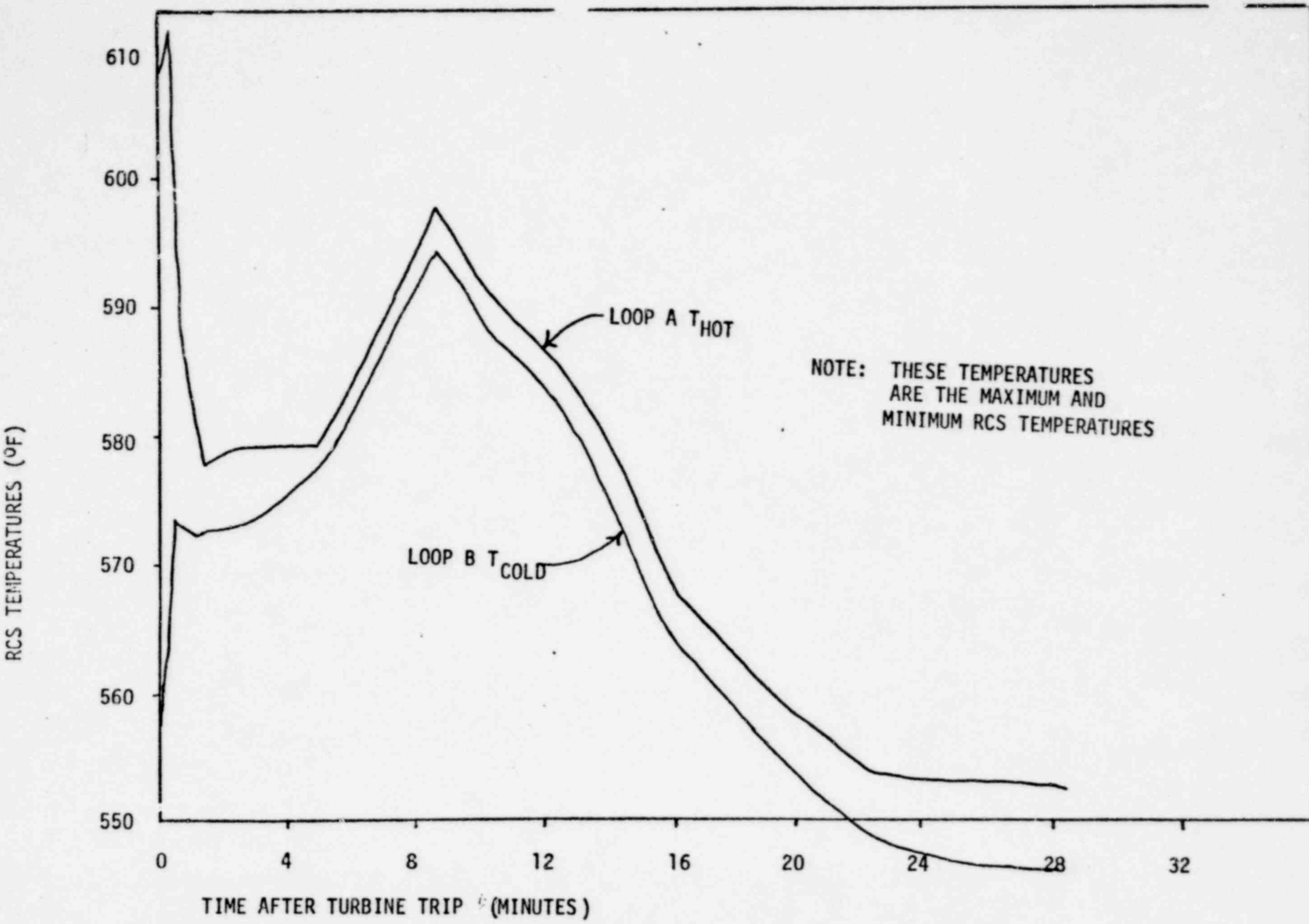


FIGURE 2.6-9 RCS LOOP TEMPERATURES FROM 0 TO 28 MINUTES

1215 158

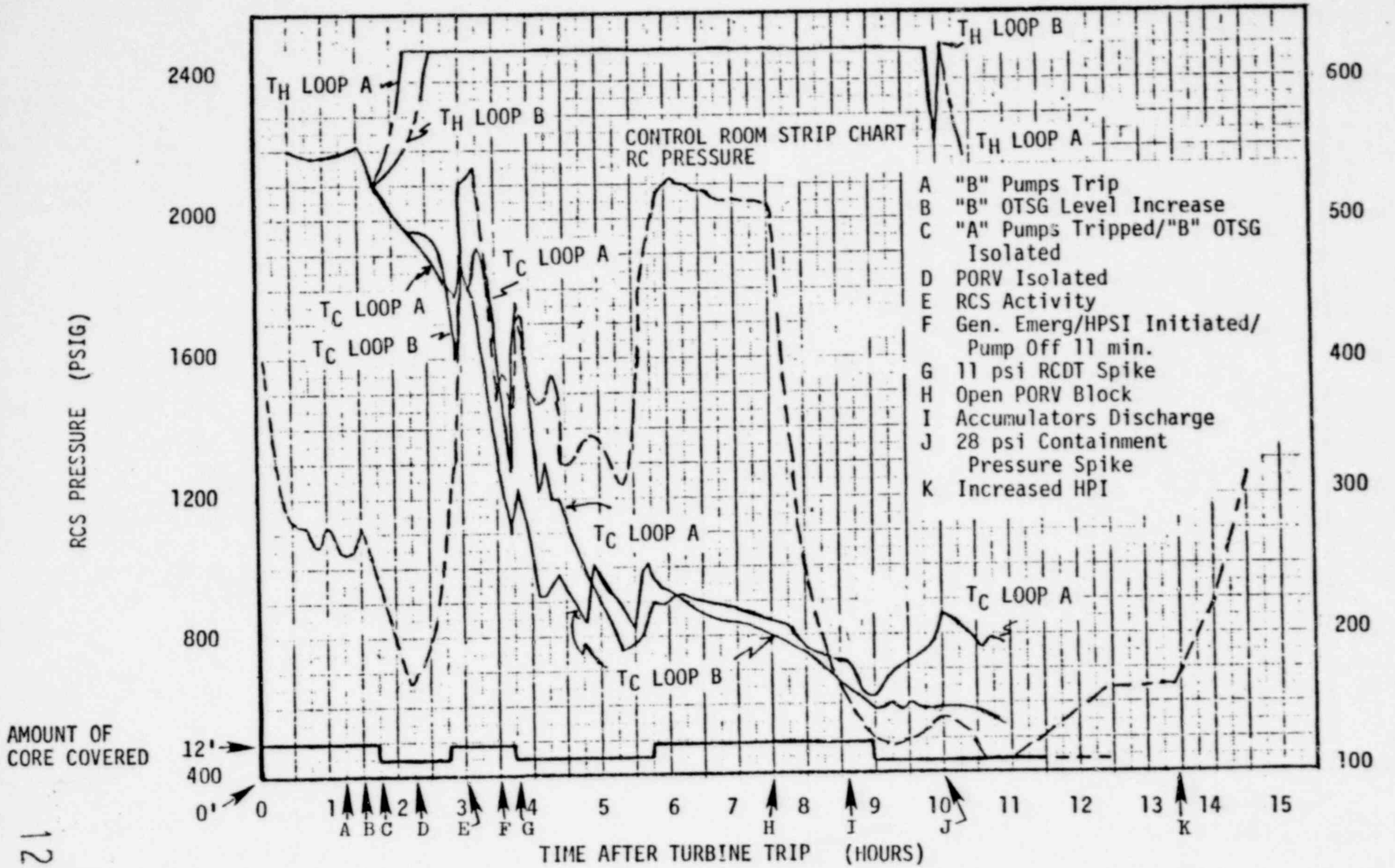


FIGURE 2.6-10 RCS PRESSURE AND T_{HOT} AND T_{COLD} LOOP TEMPERATURES FROM 0 TO 14.5 HOURS. ESTIMATED CORE UNCOVERY AND SIGNIFICANT EVENTS SUPERIMPOSED.

1215 159

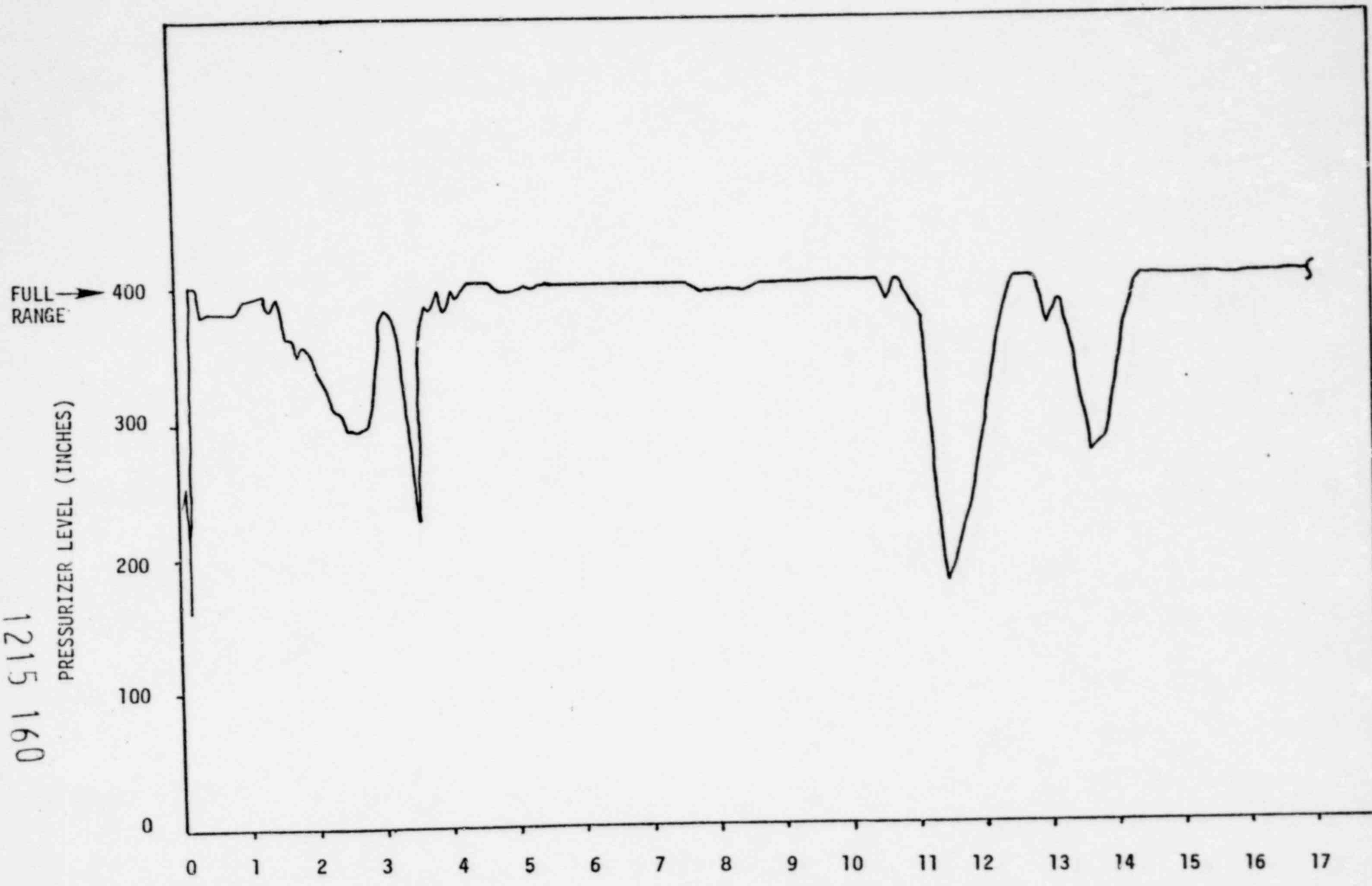


FIGURE 2.6-11 PRESSURIZER LEVEL FROM 0 TO 17 HOURS

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1215 161

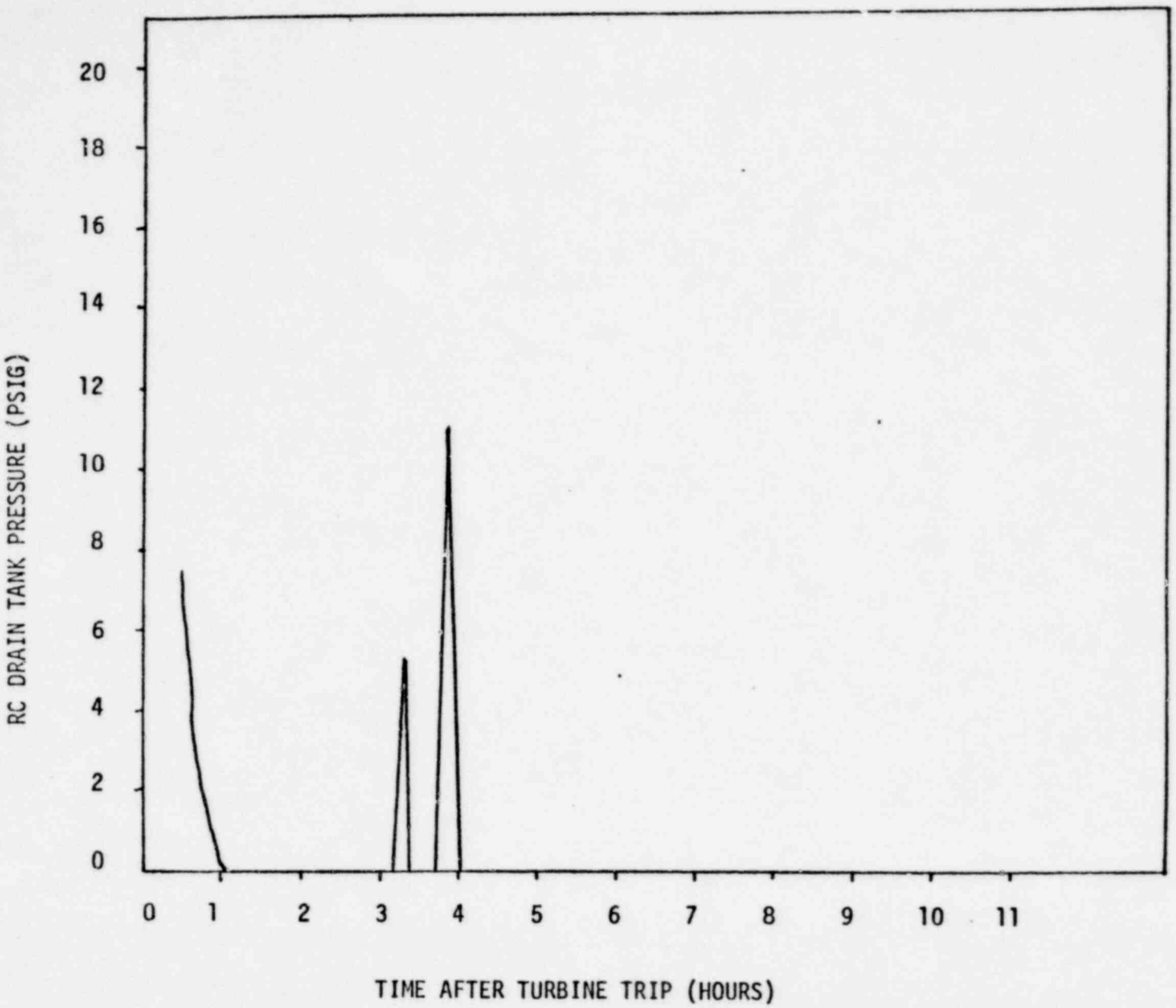

FIGURE 2.6-12 REACTOR COOLANT DRAIN TANK PRESSURE FROM 1/2 to 11 HOURS

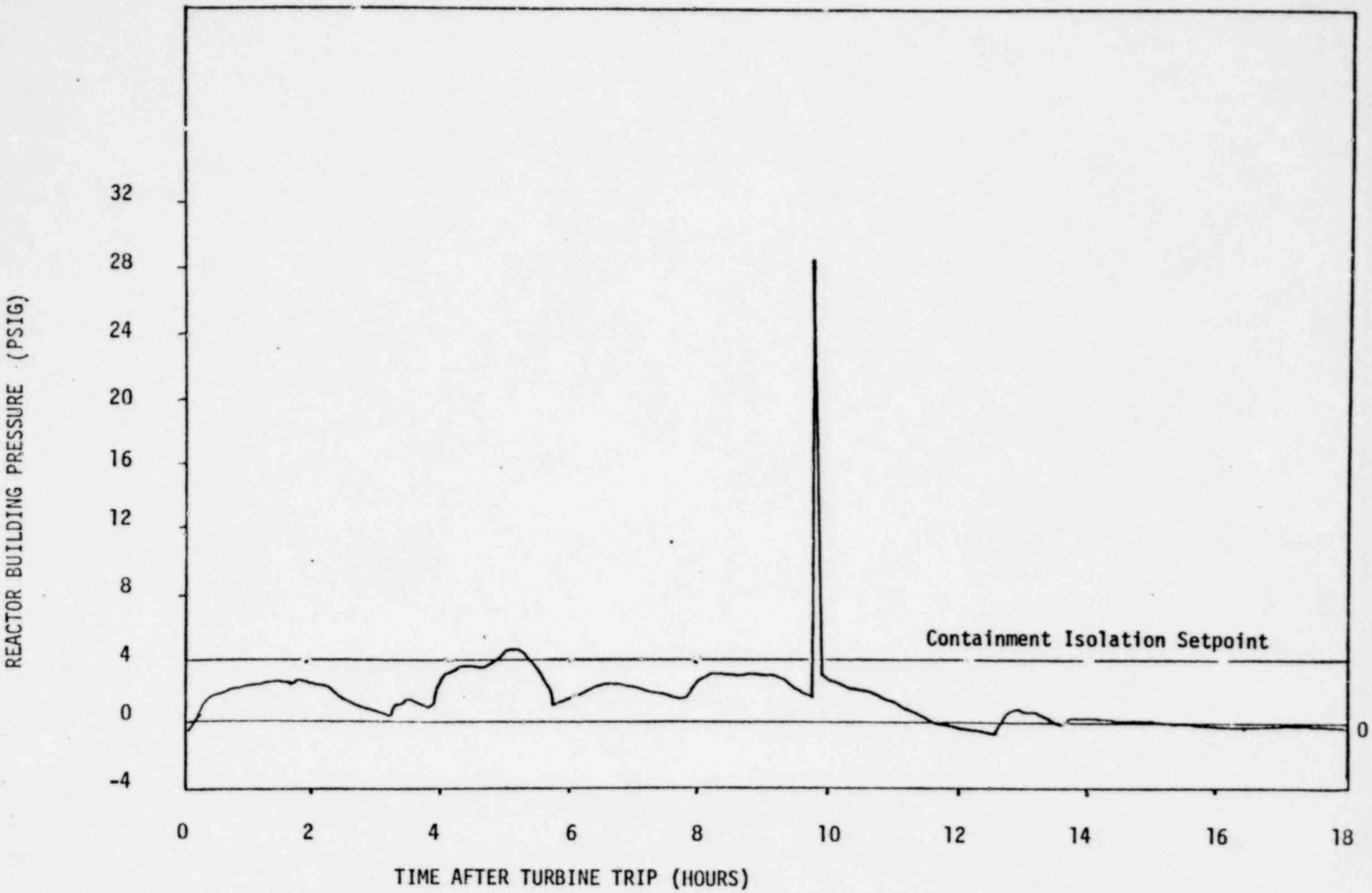

FIGURE 2.6-13 REACTOR BUILDING (CONTAINMENT) PRESSURE FROM 0 TO 18 HOURS

1215 162

SECTION 3

THREE MILE ISLAND/POINT BEACH COMPARISON

3.1 GENERAL DESCRIPTION OF THREE MILE ISLAND

The Three Mile Island Nuclear Station Unit 2 (TMI) is a Babcock and Wilcox (B&W) pressurized water reactor design. The reactor coolant system (RCS) consists of the following components: the reactor vessel, two steam generators, four reactor coolant pumps, one pressurizer, and interconnecting piping. The RCS interfaces at the steam generators with the secondary plant of conventional design. The major components in the secondary plant are the following: the turbine-generator set with one high pressure and two low pressure turbines, four moisture separator reheaters, two surface condensers, two condensate storage tanks, three condensate pumps, a 100% flow mixed bed polishing system, three condensate booster pumps, two steam generator feed pumps, and six heat exchangers in the feedwater system. The condensers are cooled by a circulating water system which consists of six circulating water pumps and two natural draft cooling towers. These are schematically shown in Figure 3.1-1. Other support and auxiliary systems exist but are not described here, except for emergency feedwater.

A flow diagram of the RCS at full power, steady state conditions is given in Figure 3.1-2. This shows relative volumes (V), temperatures (T), pressures (P), and flows (F), as well as the loop connections. There are two hot legs and four cold legs in the RCS. The surge line is connected to one of the hot legs and the spray line (not shown) is connected to one of the cold legs, between the pump and vessel, in that same loop. A plan view of the RCS layout is given in Figure 3.1-3 and shows the relative position of each component and connecting piping. As shown, the inlets and outlets are matched and oppose each other every 60° where they connect to the reactor vessel. The piping also has welded connections for pressure taps, temperature elements, vents, drains, decay heat removal, and emergency core cooling high pressure injection water. A thermal sleeve is provided in the high pressure injection connection to the reactor coolant inlet piping.

The outlet piping from the vessel to the steam generators has an inside diameter of 36". After leaving the vessel it travels in a horizontal plane for several feet, undergoes a 90° bend, runs upward for approximately 45 feet, makes a 180° bend, and enters the top plenum of the steam generator. This is shown in Figure 3.1-4. At the steam generator outlet, the loop consists of two 28" inside diameter pipes. Both of these leave the steam generator lower plenum from the side, make a greater than 90° bend and run upward for approximately 33 feet before entering the suction nozzle at the bottom of the pump. The pump centerlines are placed at an elevation approximately 3.5 feet above the horizontal plane of the inlet nozzles. Upon leaving the pump discharge nozzle, the 28" inside diameter pipe drops down and enters the reactor vessel completing the loop.

Figure 3.1-5 shows the change in B&W plant component elevations from the early Oconee and TMI arrangements to the later Davis Besse type. The latter design provides for better natural circulation conditions with a larger driving head due to the greater steam generator elevation. There is also minimal static head to overcome from the steam generator outlet pipe lower bend to the pump elevation (reduced volume and a static head decrease from 33'-3" to 5'-9"). This provides that the core will remain covered should the loop be drained and also prevents siphoning of coolant from the reactor during refueling or maintenance.

The reactor vessel is designed to support and house the reactor core support assembly, plenum assembly, nuclear fuel assemblies, control rod assemblies, and incore instrumentation. The vessel and internals are shown in Figure 3.1-6. The reactor vessel consists of a cylindrical shell, a spherically dished bottom head, and a ring flange to which a removable reactor closure head is bolted. The reactor vessel is supported by a cylindrical support skirt.

The reactor vessel closure head is a spherically dished head, welded to a ring flange which mates with, and is bolted to, the vessel with large-diameter studs. All internal surfaces of the vessel and closure head are clad with stainless steel or nickel-chrome-iron (Ni-Cr-Fe) weld deposit. The closure head is penetrated by flanged nozzles which provide for attaching the control rod drive mechanisms and for control rod extension shaft movement. The closure head is also penetrated by eight thermocouple nozzles. Two concentric metallic O-rings provide the pressure integrity seal between the closure head and the vessel flanges. A high pressure leak off and drain tap is provided at the annulus between the two O-rings.

The core support assembly is supported by a ledge on the inside of the vessel flange and its location is maintained at this elevation by the closure head flange. The core support assembly directs coolant flow through the reactor vessel and core, supports the core, and guides the control rods in the withdrawn position.

The coolant enters the reactor through the inlet nozzles, passes down through the annulus between the thermal shield and vessel inside wall, reverses at the bottom head, passes up through the core, turns around through the plenum assembly, and leaves the reactor vessel through the outlet nozzles. Eight 14-inch inside diameter internals vent valves are installed in the core support assembly. They are equally spaced around the circumference of the core support shield wall in a plane located 42 inches above the centerline of the vessel nozzles. Each valve consists of a hinged disc, valve body with sealing surfaces, and split-retaining ring. Under normal operating conditions, the vent valves will be held closed by the greater pressure of the water entering the annulus from the pumps. In the event of a break in the inlet piping, the vent valves will open due to a reverse in pressure which permits steam generated in the core to exit without travelling down thru the core and up the annulus. These valves might also open when there is no pumped reactor coolant flow.

The vessel has two outlet nozzles through which the reactor coolant is discharged to the steam generators and four inlet nozzles through which reactor coolant re-enters the reactor vessel. Two smaller nozzles located between the reactor coolant inlet nozzles serve as inlets for decay heat cooling and emergency cooling water injection (core flooding and low-pressure injection engineered safety features functions). The reactor coolant and the control rod drive penetrations are located above the top of the core to maintain a flooded core in the event of a rupture in a reactor coolant pipe or a control rod drive pressure housing. The bottom head of the vessel is penetrated by instrumentation nozzles.

Guide lugs welded inside the reactor vessel's lower head limit a vertical drop of the reactor internals and core to 1/4 inch or less and prevent rotation about the vertical axis in the unlikely event of a major internals component failure. These lugs provide shock support for the internals and control the motion of the lower end of the core support assembly while under the influence of horizontal seismic loads.

The steam generators are designed to remove the heat generated by the reactor vessel through the process of producing superheated steam in the secondary side. The steam generator is shown in Figure 3.1-7. The steam generator is a vertical, straight-tube-and-shell heat exchanger and produces superheated steam which is controlled to maintain a constant throttle pressure over the power range. Reactor coolant flows downward through the tubes, and steam is generated on the shell side. The high pressure parts of the unit are the hemispherical heads, the tubesheets, and the straight Inconel tubes between the tubesheets. Tube supports hold the tubes in a uniform pattern along their length.

The shell, the outside of the tubes, and the tubesheets form the boundaries of the steam producing section of the vessel. Within the shell, the tube bundle is surrounded by a baffle, which is divded into two sections. The upper part of the annulus between the shell and baffle is the superheater outlet, and the lower part is the feedwater inlet-heating zone. Auxiliary feedwater is injected into the tube bundle just below the upper tubesheet at the top edge of the baffle. Vents, drains, instrumentation nozzles, and inspection openings are provided on the shell side of the unit. The reactor coolant side has manways on both heads, and a drain nozzle for the bottom head. Venting of the reactor coolant side of the unit is accomplished by a vent connection on the reactor coolant inlet pipe to each unit. The unit is supported by a skirt attached to the bottom head.

Reactor coolant water enters the steam generator at the upper plenum, flows down the Inconel tubes while transferring heat to the secondary shell-side fluid, and exits through the lower plenum. Figure 3.1-8 shows the flow paths and steam generator heating regions.

Four heat transfer regions exist in the steam generator as feedwater is converted to superheated steam. Starting with the feedwater inlet, these are as follows:

A. Feedwater Heating - Feedwater is heated to saturation temperature by direct contact heat exchange. The feedwater entering the unit is sprayed into a feedheating annulus (downcomer) formed by the shell and the baffle around the tube bundle. The steam that heats the feedwater to saturation is drawn into the downcomer by condensing action of the relatively cold feedwater.

B. Nucleate Boiling - The saturated water enters the tube bundle, and the steam-water mixture flows upward on the outside of the Inconel tubes counter-current to the reactor coolant flow. The vapor content of the mixture increases almost uniformly until DNB, i.e., departure from nucleate boiling, is reached, and then film boiling and superheating occurs. The quality at which transition from nucleate boiling to film boiling occurs is a function of pressure, heat flux, and mass velocity.

C. Film Boiling - Dry saturated steam is produced in the film boiling region at the upper end of the tube bundle.

D. Superheated Steam - Saturated steam is raised to final temperature in the superheater region.

The amount of surface (or length) of the nucleate boiling section and the film boiling section is proportional to load. The surface available for superheating varies inversely with load, i.e., as load decreases, the superheat section gains from the nucleate and film boiling regions.

The reactor coolant pumps are designed to provide flow of coolant between the reactor vessel and the steam generator and for the pressurizer spray. The four reactor coolant pumps are single suction, single stage, vertical, radially balanced, constant speed centrifugal pumps. They use controlled leakage mechanical seals to prvent reactor coolant fluid leakage to the reactor building atmosphere. The inlet to each pump is a 28-inch line from the outlet plenum of the steam generator which connects to the bottom of the pump casing. The outlet from each pump is a 28-inch line connecting the side discharge nozzles to the reactor vessel inlet nozzles. The controlled leakage seals use 8 gpm of injection water with only 1 gpm of return water to the reactor coolant drain tank. Each pump develops a 362-foot head at 1190 rpm and pumps 92,400 gpm. They require a 400-foot net positive suction head.

The motor driving each pump is a 6,600 volt, three phase, squirrel cage induction, single-speed motor. It is water-cooled and develops 9,000 hp. It is mounted vertically on and supported by the pump casing. A flywheel is included in the motor to extend the flow coastdown capability upon a pump trip. An overall view of the pump and motor is given in Figure 3.1-9 and a schematic of the pump is shown by Figure 3.1-10.

The pressurizer is designed to provide the capability of maintaining the reactor coolant system above saturation pressure to prevent boiling of the coolant. The pressurizer is a veritical, cylindrical vessel which is connected to the reactor outlet piping by the surge piping. The general arrangement is shown in Figure 3.1-11. The electrically heated pressurizer establishes and maintains the reactor coolant pressure within prescribed limits and provides a surge chamber and a water reserve to accommodate changes in reactor coolant volume during operation. The designed water volume is based on the ability of the system to experience a reactor trip and not uncover the low level sensors in the lower shell and maintain the pressure high enough so as not to activate the HP injection system. The designed steam volume is based on the ability of the system to experience a turbine trip and not cover the level sensors in the upper shell. The vessel is protected from thermal effects by a thermal sleeve in the surge line connection and by a distribution baffle on the surge pipe inside the vessel.

Two American Society of Mechanical Engineering Code safety valves are connected to the pressurizer to relieve system overpressure. Each valve has one-half the required relieving capacity. An additional pilot-operated relief valve is provided to limit the lifting frequency of the Code safety valves. The three relief valves discharge to the reactor coolant drain tank within the reactor containment building.

Replaceable electric heater bundles in the lower section and a water spray nozzle in the upper head maintain the steam and water at the saturation temperature corresponding to the desired reactor coolant system pressure.

There are 13 groups of heaters in 5 banks. They have a total heat input of 1638 kw. There is a single spray line from the adjacent cold leg piping. During outsurges, as the pressure in the reactor coolant system decreases, some of the water in the pressurizer flashes to steam to maintain pressure.

Electric heaters are actuated to restore the normal operating pressure. During insurges, as pressure in the reactor coolant system increases, a water spray from the reactor cold leg condenses steam, thus reducing pressure. Spray flow and heaters are controlled by the pressurizer's pressure controller. The pressurizer spray nozzle contains a thermal sleeve which protects it from thermal shock due to cold water surges.

To eliminate abnormal buildup or dilution of boric acid within the pressurizer and to minimize cooldown of the coolant in the spray and surge lines, bypass flow is provided around the pressurizer spray control valve which continuously circulates approximately 1 gpm of reactor coolant from the heat transport loop. A sampling connection to the liquid volume of the pressurizer is provided for determining boric acid concentration. A steam space sampling line provides capability for sampling and/or venting accumulated gases.

During cooldown and after the decay heat removal system is placed in service, the pressurizer can be cooled by circulating water through a connection from the discharge of the decay heat removal pump to the pressurizer spray line. The radwaste disposal, reactor coolant leakage recovery system is designed to accommodate the effluent from the pressurizer relief and safety valves when the valves relieve. The reactor coolant drain tank, which collects the pressurizer relief discharge, is designed to accommodate a total of 3500 pounds of steam at an average enthalpy of 1140 Btu/lb. The safety valves are rated at 383,227 lb/hr, giving an actual flowrate of 851,620 lb/hr for the two safety valves. The pilot operated relief valve discharges at 118,909 lb/hr. A total of 970,529 lb/hr is discharged to the drain tank during the recovery system design transient.

The radwaste disposal, reactor coolant leakage recovery system consists of the reactor coolant drain tank, pumps, heat exchangers, valves and piping necessary to collect and cool Reactor Coolant System leakage and to collect, quench and cool pressurizer relief valve discharges and to transfer the cooled fluid for processing and recovery. The entire system is located in the reactor building. The system diagram is shown in Figure 3.1-12. In addition to the relief discharge functions of the radwaste disposal, reactor coolant leakage recovery system, the system collects reactor coolant system leakage from the stems of power operated valves within the reactor coolant pressure boundary, pressurizer safety and pilot operated relief valve seats and the reactor coolant pump seals.

The pressurizer relief discharge function of the system is served by piping from the discharges of the pressurizer safety and pilot operated relief valves through a 14-inch inlet pipe to the reactor coolant drain tank. Interconnections from the valve stem leakoffs, the demineralized water supply, the nitrogen supply and a vacuum relief line from the drain tank vent are provided on the inlet line. The inlet line extends into the tank where it discharges into four 8-inch horizontal pipes located approximately 4 feet -8 inches below the minimum water level in the tank. The 8-inch pipes are open ended for steam flow and have 3/4 inch holes bored radially through the pipe wall to induce water circulation in the tank during pressurizer relief discharges. Any leakage past the seats of the pressurizer safety and pilot operated relief valves is also carried to the drain tank.

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All leakage from valve stem leakoffs passes through a 2 inch line to the drain tank below the minimum water level. Leakage from the reactor coolant pump seals is carried into the drain tank by way of a separate 2 inch nozzle approximately 1 foot below the minimum water level in the drain tank.

Cooling is provided by an operator-activated external recirculation loop which takes suction from the reactor coolant drain tank. Flow through the external loop is provided by the leakage transfer pumps and heat removal to the decay heat closed cooling water system is provided by the leakage coolers. The cooled drain tank water is returned to the drain tank through two 4 inch nozzles. Transfer of the cooled leakage or relief discharge is by way of a 4 inch interconnection to the reactor coolant drain header and the radwaste disposal, reactor coolant liquid system.

The drain tank is blanketed with nitrogen to provide an inert diluent for hydrogen that is released with reactor coolant leakage or pressurizer relief discharges. The radwaste disposal, reactor coolant leakage recovery system is sized to accommodate 30 gpm leakage from the reactor coolant system and maintain the reactor coolant drain tank at 126 degrees F. Following the addition of the 3500 lb. discharge from the pressurizer safety and relief valves, the drain tank will reach 193 degrees F at a pressure of 46 psig. The cooling loop will reduce the temperature of the tank within two hours subsequent to the relief valve discharge with the full leakage rate continuously applied.

The reactor coolant drain tank vent, which is normally open to the reactor coolant bleed holdup tanks, closes when the drain tank pressure rises above 10 psig and reopens when the tank drops below 6 psig to prevent a vacuum condition from occuring.

The relief valve on the drain tank has a liquid relief capacity of 2270 gpm with a setpoint of 150 psig which is greater than the pressurizer relief discharge rate of 2058 gpm liquid quenched to 250 degrees F. In the event of a sustained relief valve discharge to the drain tank, the tank and system are protected by a rupture disc with a burst pressure of 195 psig and capacity for steam relief at a rate of 472 lb/sec., approximately 1.75 times the maximum pressurizer relief rate (270 lb/sec).

The reactor coolant drain tank is provided with level indication, alarms for high and low level, and an alarm and system isolation interlock for low tank level. The level instrumentation assures that sufficient capacity to accept the design pressurizer relief is available at all times and that a minimum quench water inventory is retained during the transfer of accumulated reactor coolant leakage or pressurizer relief discharges to the reactor coolant bleed holdup tanks. The quench water level is maintained at or above 6 feet in the tank at all times.

The tank pressure is monitored by indication and high and low pressure alarms provided. Additionally tank pressure is used to provide vent isolation for bleed holdup tank protection and to provide drain tank vacuum relief.

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Leakage direction is accomplished by use of temperature elements for power operated valve stem leakoffs and the pressurizer relief and safety valve seat leakage. Flow indication is provided for continuous monitoring of reactor coolant pump seal leakage with a common high flow alarm to annunciate abnormal conditions.

Flow from the system to the bleed holdup tanks is recorded for use in conjunction with drain tank level indications to determine the known leakage rate from the reactor coolant system.

The Steam and Power Conversion System is utilized to convert heat energy from the reactor coolant to electrical energy. Pressurized reactor coolant is pumped through the reactor core from which it removes heat and then through the tubeside of two once-through steam generators where steam is produced on the steam generator shell side. In the event of primary to secondary leakage, radioactive fission and corrosion product removal can be effected by the condensate polishing system. The steam generated within the steam generators is supplied via two main steam lines from each steam generator to a tandem compound, two stage reheat, four flow turbine, which is utilized to generate electric power. The only cross connection between steam generators is in the turbine steam chest between the turbine stop valves and control valves.

The main steam lines penetrate the Reactor Building, pass through the Control Building Area and then enter the Turbine Building. Main steam isolation valves, which can be closed remotely from the control room are located in the Control Building Area. The closure time for these valves, which are tight closing, is two minutes or less. Upstream of the main steam isolation valves are the main steam safety valves, and steam line take-offs for steam bypass to the condenser, for controlled steam relief to the atmosphere, and for the steam supply to the main and emergency steam generator feedpump turbines. Since there are no cross-connections between steam generators, rupture of a line from one steam generator will not blow the other steam generator dry. This insures that a continued steam supply is available to the main and emergency steam generator feedpump turbines.

Steam is supplied to the high pressure turbine at 900 psia and 560°F. The high pressure turbine exhaust enters four identical Moisture Separator-Reheater units where excess moisture is removed and the steam is reheated before entry into the two low pressure turbines. The turbine unit has six steam extraction stages which are utilized for feedwater heating. The exhaust system from the low pressure turbines is condensed, deaerated and collected in a dual pressure main surface condenser.

The condenser circulating water system is a closed system, cooled by two natural draft cooling towers. Make-up for tower evaporation, wind loss, and blowdown is supplied from the Secondary Services River Water System.

Off-gas from the Condenser Air Extraction System is continuously monitored for radioactivity levels which are indicated in the control room. Abnormal levels will be alarmed. Off-gas is normally passed through the Auxiliary Building Ventilation System prior to being released to the unit vent and the environment.

The condensate pumps take suction from the condenser hotwell and discharge through a mixed bed polishing system to the condensate booster pumps. The polishing system maintains water quality and is capable of removing impurities in the secondary system resulting from corrosion or leakage into the secondary system.

The condensate booster pumps discharge through two half-capacity parallel trains of low pressure heaters to the steam generator feedpumps. In addition, heater drain pumps are used to discharge the cascaded drains from the Moisture Separator-Reheater units and the last two heater stages to the steam generator feedpump suction.

Each of the two steam generator feedpumps discharges through a high pressure feedwater heater, through feedwater regulating valves, to one of the two steam generators (see Figure 3.1-13).

There are also two 470 gpm capacity motor-driven emergency steam generator feedpumps and one 940 gpm capacity turbine-driven emergency steam generator feedpump to supply feedwater to the steam generators in the event that the main steam generator feedwater pumps are not available. The suction header for the emergency steam generator feedpumps is fed from any of the following sources: the condensate pump discharge, the condensate storage tanks, or from either redundant branch of the Nuclear Services River Water System.

Upon loss of full load, the system will dissipate all the energy existent or produced in the reactor coolant system through steam relief to the condenser and the environment.

The Engineered Safety Features (ESF) systems, provided for Three Mile Island Nuclear Station Unit 2, consist of the containment systems and the Emergency Core Cooling Systems (ECCS). The containment systems are designed to mitigate the consequences of a loss of coolant accident (LOCA) by reducing temperature and pressure within containment and limiting leakage. The Emergency Core Cooling Systems are provided to limit the consequences of a LOCA by removing heat to minimize metal water reactions and to prevent core meltdown.

The containment systems consist of the following:

A. The containment structure including the liner - A reinforced concrete structure composed of 4 foot thick cylindrical walls (130 feet inside diameter) prestressed with a grouted tendon post-tensioning in the vertical and horizontal directions, a foundation mat 11 feet - 6 inches thick with conventional carbon steel reinforcing, a shallow dome roof prestressed utilizing a three-way grouted tendon post-tensioning system, and a carbon steel liner with plate thicknesses of 1/2 inch for the dome, 3/8 inch for the cylinder and 1/4 inch for the base which is covered with an additional 2 foot thick concrete slab. This is a passive ESF system.

B. Containment isolation valves - Various types of double isolation valves located on each side of the reactor building penetration in piping systems which have portions both inside and outside the reactor building. All isolation valves inside or outside containment which are not normally locked closed and all remotely operated isolation valves inside the containment have position indicators in the control room. This is an active ESF system where valves are automatically closed upon containment pressure reaching 4 psig.

C. Containment air purification and heat removal systems - The reactor building spray system which, when containment isolation aligns the valves at 4 psig and activated at 30 psig by high containment pressure, supplies spray to cool the building, reduce pressure, and remove radioiodine and radioactive particles from the containment atmosphere. The spray fluid is supplied from the borated water and sodium hydroxide storage tanks through two 50% circuits each consisting of a suction header, pump, and a 96 nozzle spray header. Suction can be taken from the containment sump when the borated water storage tank inventory is depleted. The reactor building air cooling system consists of five common ducted, electric motor-driven axial flow fan units with finned, water type, cooling coils and back draft damper for individual isolation.

D. Combustible gas control - A hydrogen recombiner and containment purge system consisting of continuous monitoring of the containment atmosphere to determine hydrogen content, a thermal recombiner located outside of containment which can take a suction through either of two purge outlet penetrations when operator initiated, and a purge through a prefilter, a high efficiency particulate air filter, an activated charcoal filter, a second high efficiency particulate air filter, and out to the atmosphere via the unit vent.

The ECCS consists of the following as related to Figure 3.1-14:

A. Core flooding system - The system consists of two tanks located within the reactor building, each tank outlet connects to one of the two 11-1/2 inch flooding nozzles in diametrically opposite locations on the reactor vessel above the core zone. Each of the tanks and its related equipment function as an independent circuit. Both circuits are required for the system to meet its design requirements. This is a passive safety system. Release of the stored borated water to the reactor core is independent of actuation signals, electric power supplies, or operator action. The core flooding water is released by action of check valves in the outlet line from the tanks which are normally held closed by reactor coolant system pressure. The closed check valves open when the coolant system pressure is reduced below 600 psig. This pressure is maintained in the flooding tanks during normal operation by an overpressure of nitrogen gas. Any accident which results in the loss of reactor coolant system pressure (like a large reactor coolant system piping failure) therefore, initiates core flooding when pressure drops below 600 psig. Each tank contains approximately 7,800 gallons of borated water at a minimum concentration of 2270 parts per million of boron and pressurized with nitrogen gas to 600 (+25,-0) psig.

B. The reactor coolant makeup and purification system in the high pressure safety injection mode (HPSI) - The system uses the high discharge capability of the makeup pumps to inject borated water from the borated water storage tank (BWST) directly into the RCS piping. Three pumps are available, one in each of two separate trains and a spare capable of supplying either train. Recirculation of RCS water spilled to the containment is accomplished with the HPSI pumps taking a suction from the outlet of the decay heat removal system heat exchanger. In this case, the decay heat pumps provide the required NPSH for operation of the makeup pumps by recirculating water from the reactor building sump.

C. The decay heat removal system in the low pressure safety injection mode (LPSI) - The system provides low pressure injection of borated water into the reactor core during emergency conditions, and long term core cooling during post accident conditions by recirculation from the reactor building sump. The system is comprised of two parallel and independent circuits. Either circuit will satisfy the low pressure injection requirements imposed by a LOCA. Borated water from the BWST and sodium hydroxide from the sodium hydroxide tank is injected by the pumps into the reactor vessel after the reactor coolant has fallen below the maximum discharge pressure capability of the pumps. When the BWST level has been reduced to its minimum level, the system is aligned by automatic actuation to recirculate the water in the reactor building sump back to the reactor. Each of the two LPSI pumps discharge the coolant into the tube side of its associated circuit heat exchanger. The reactor coolant, after passing through the heat exchanger, is returned to the reactor vessel through the two independent 11-1/2 inch core flooding nozzles, thereby completing the circuit. By recirculating the reactor coolant in this manner, the coolant temperature is reduced and the decay heat of the reactor core is dissipated to the river via the component cooling and service water systems. Normal operation of the system circulates primary coolant within the RCS and through one or both heat removal loops to provide cooling based on the core decay heat production level.

The sump in containment is a 280 cubic foot stainless steel lined pit partitioned into a wet and dry section. The sump receives flow from the containment floor drains, fuel transfer canal drains, decay heat removal piping drains, and the reactor coolant drain tank relief valves. During a loss of coolant accident, the water in the wet section will overflow into the dry section where the decay heat removal system and containment spray system suctions are located.

The two single stage centrifugal sump pumps each have a design capacity of 140 gpm (200 gpm maximum) and are powered by 7.5 hp electric motors. In the automatic mode of operation, the first pump starts when the sump water level increases above 38 inches; at 53 inches, the second pump starts and the condition is alarmed. In the manual mode of operation, the selected pump(s) will start and run until the level decreases and actuates the low level trip(s) to stop the pump(s). The pumped water can flow to either the Miscellaneous Waste Holdup Tank or the Auxiliary Building Sump Tank, as shown in Figure 3.1-15. The pumps are stopped and the system isolated on receipt of a containment isolation signal (>4 psig containment pressure). During the TMI accident, the pumps started automatically on increasing level and pumped reactor coolant system water to the

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Auxiliary Building Sump Tank until it was full and then out the rupture disk opening (it is understood that this had previously failed and was scheduled for repair) onto the auxiliary building floor.

The above general description of the Three Mile Island Nuclear Station Unit 2 includes only basic discussions of the reactor coolant, secondary steam, and ESF systems. These were the major systems involved in the TMI accident. Each discussion includes the description of equipment in the system, general operation or system function, and instrumentation as appropriate to the accident.

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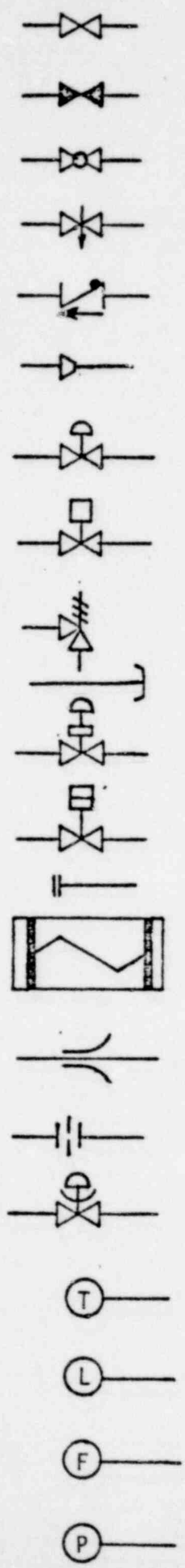
KEY TO FIGURES



- NORMALLY OPEN / NORMALLY CLOSED — GATE VALVE
- GLOBE VALVE
- NEEDLE VALVE
- CHECK VALVE
- REDUCER
- AIR DIAPHRAGM OPERATOR
- ELECTRICAL MOTOR OPERATOR
- SAFETY RELIEF VALVE
- CAPPED PIPE
- PROPORTIONAL CONTROLLED AIR OPERATOR
- PISTON OPERATOR
- BLIND FLANGE
- HEAT EXCHANGER
- FLOW RESTRICTOR
- FLOW RESTRICTION ORIFICE
- SAUNDERS PATENT DIAPHRAGM VALVE
- TEMPERATURE INDICATOR
- LEVEL INDICATOR
- FLOW INDICATOR
- PRESSURE INDICATOR

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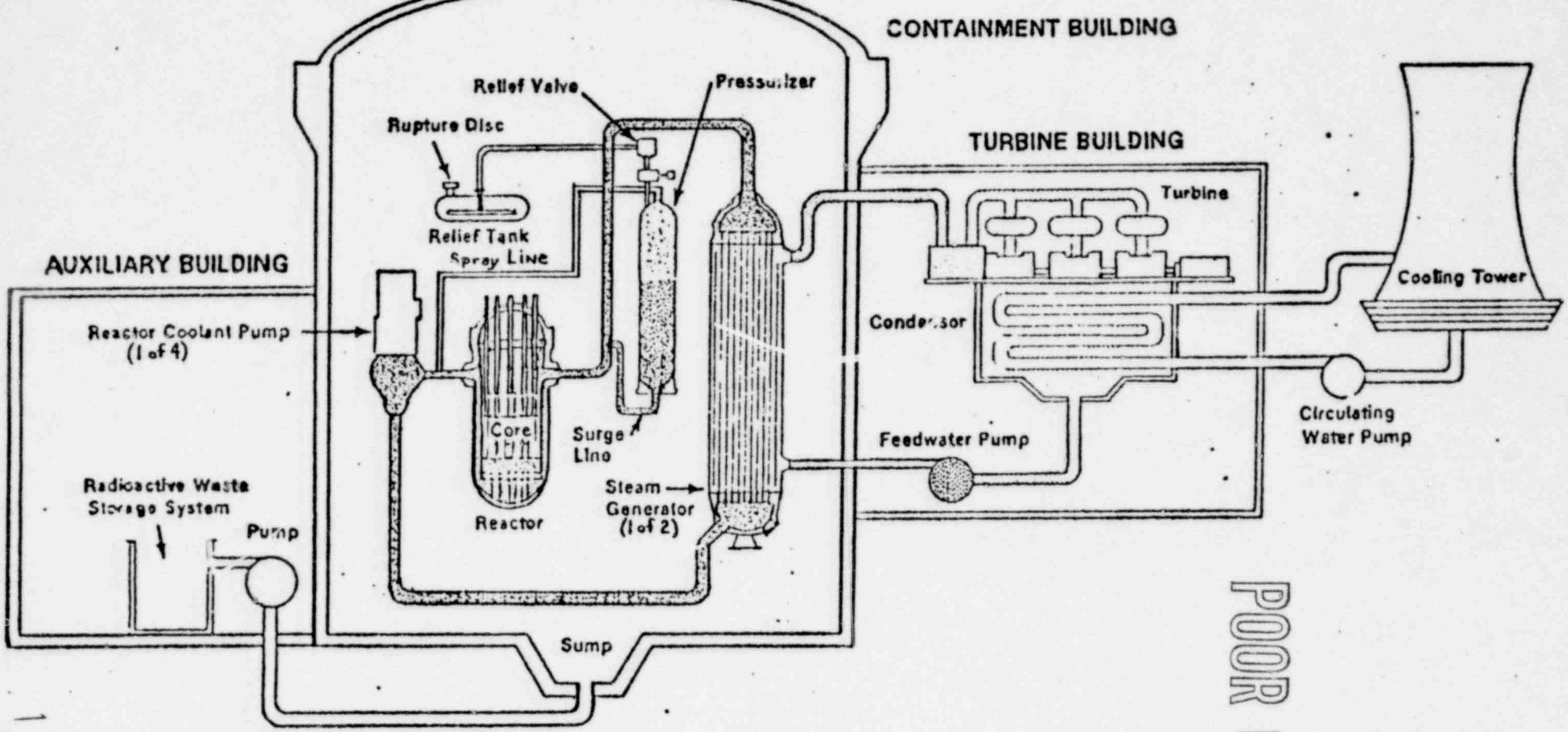
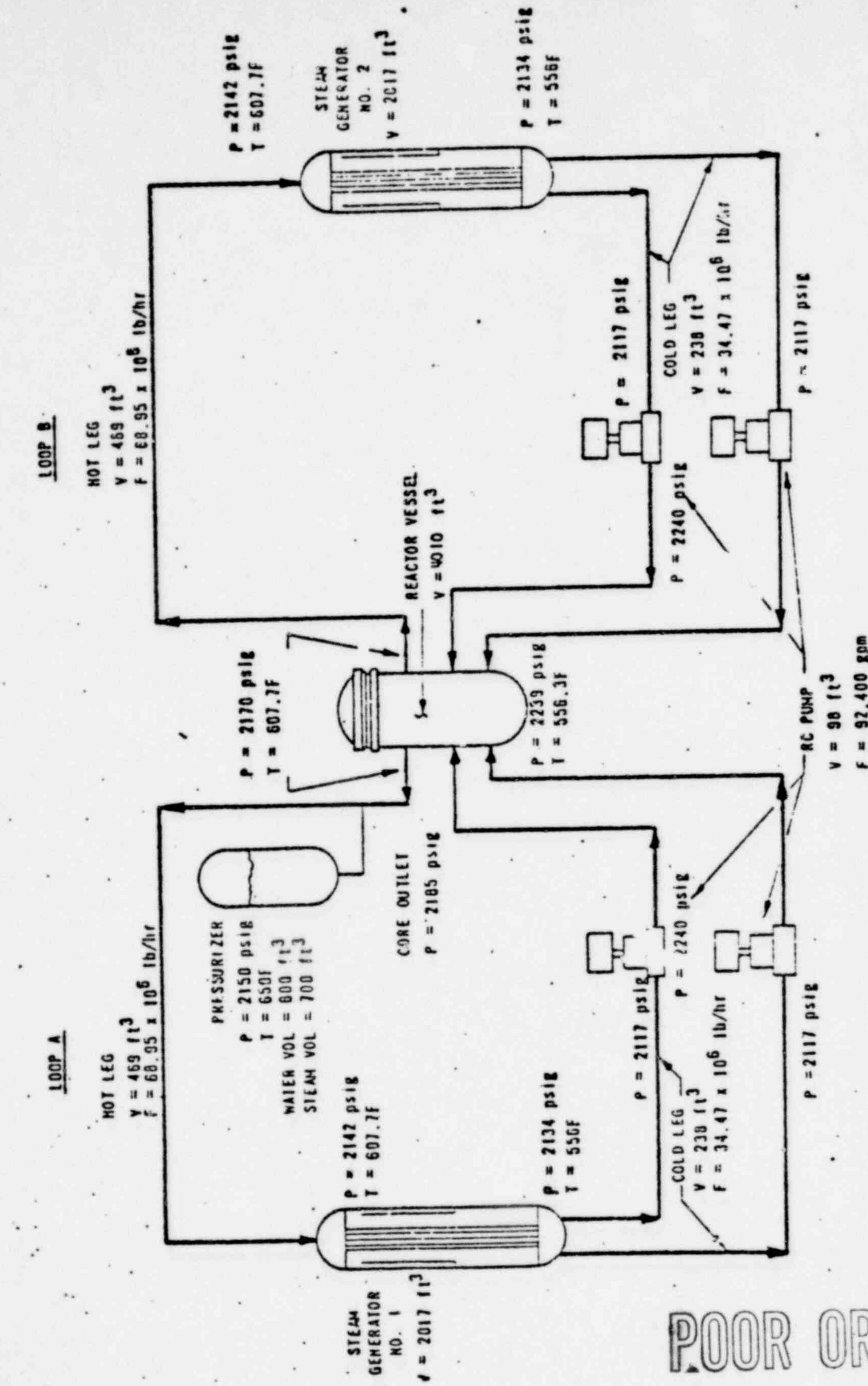


FIGURE 3.1-1 ARTISTIC ILLUSTRATION OF TMI



REACTOR COOLANT SYSTEM FLOW DIAGRAM
AT FULL POWER STEADY STATE CONDITION

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

FIGURE 3.1-2

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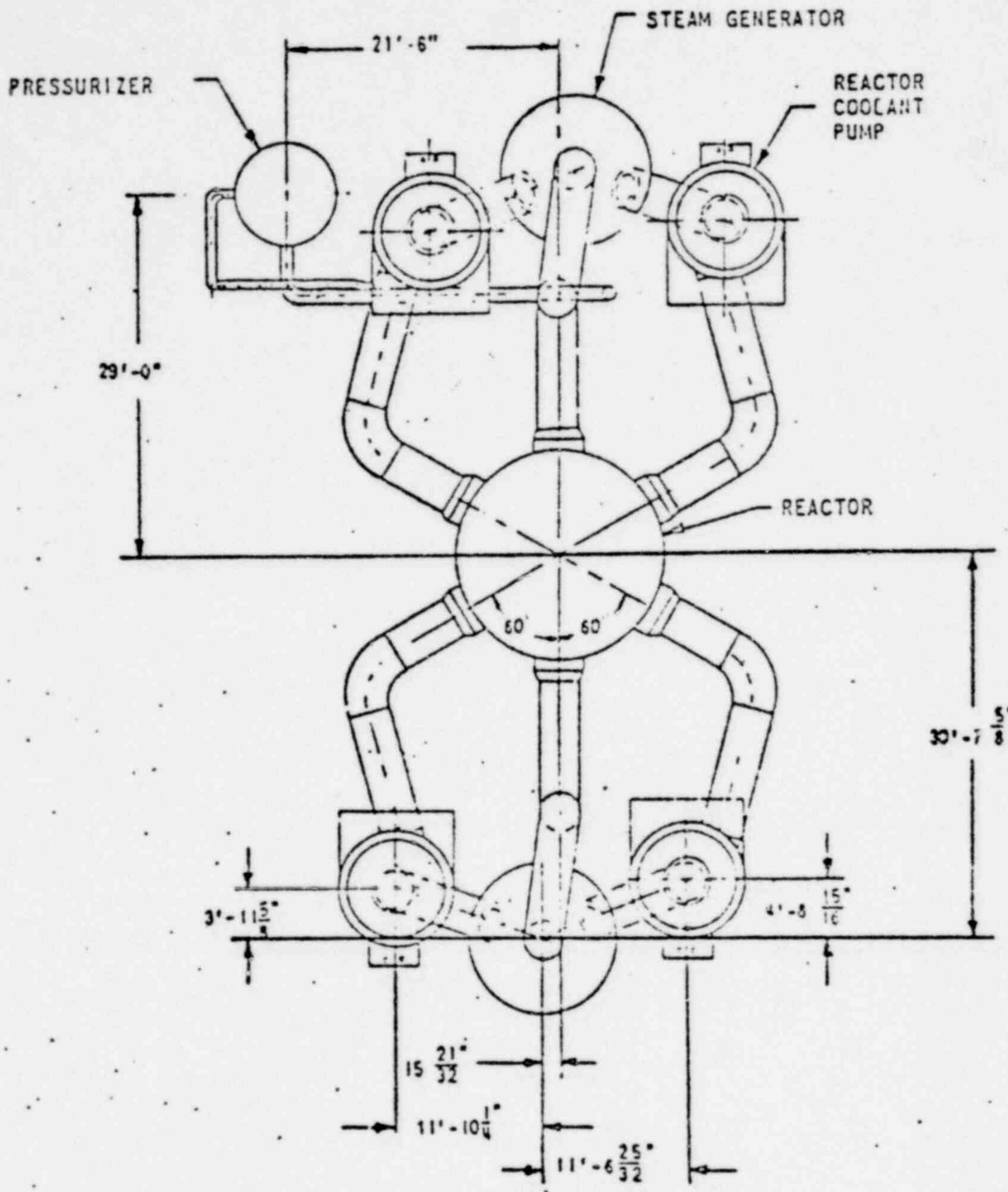

REACTOR COOLANT SYSTEM ARRANGEMENT – PLAN

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

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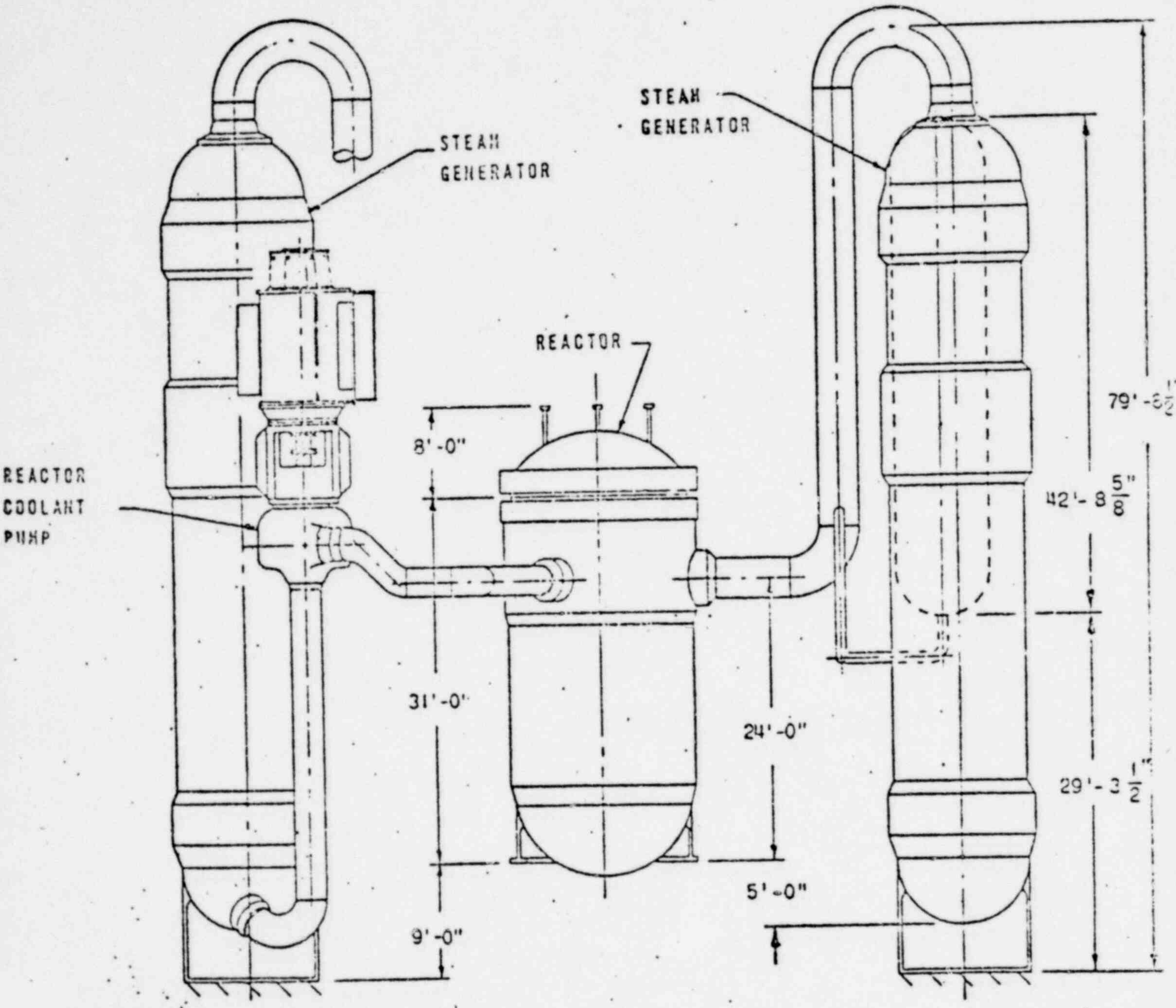
FIGURE 3.1-3



REACTOR COOLANT SYSTEM ARRANGEMENT - ELEVAT

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

1215 178

FIGURE 3.[illegible]-4

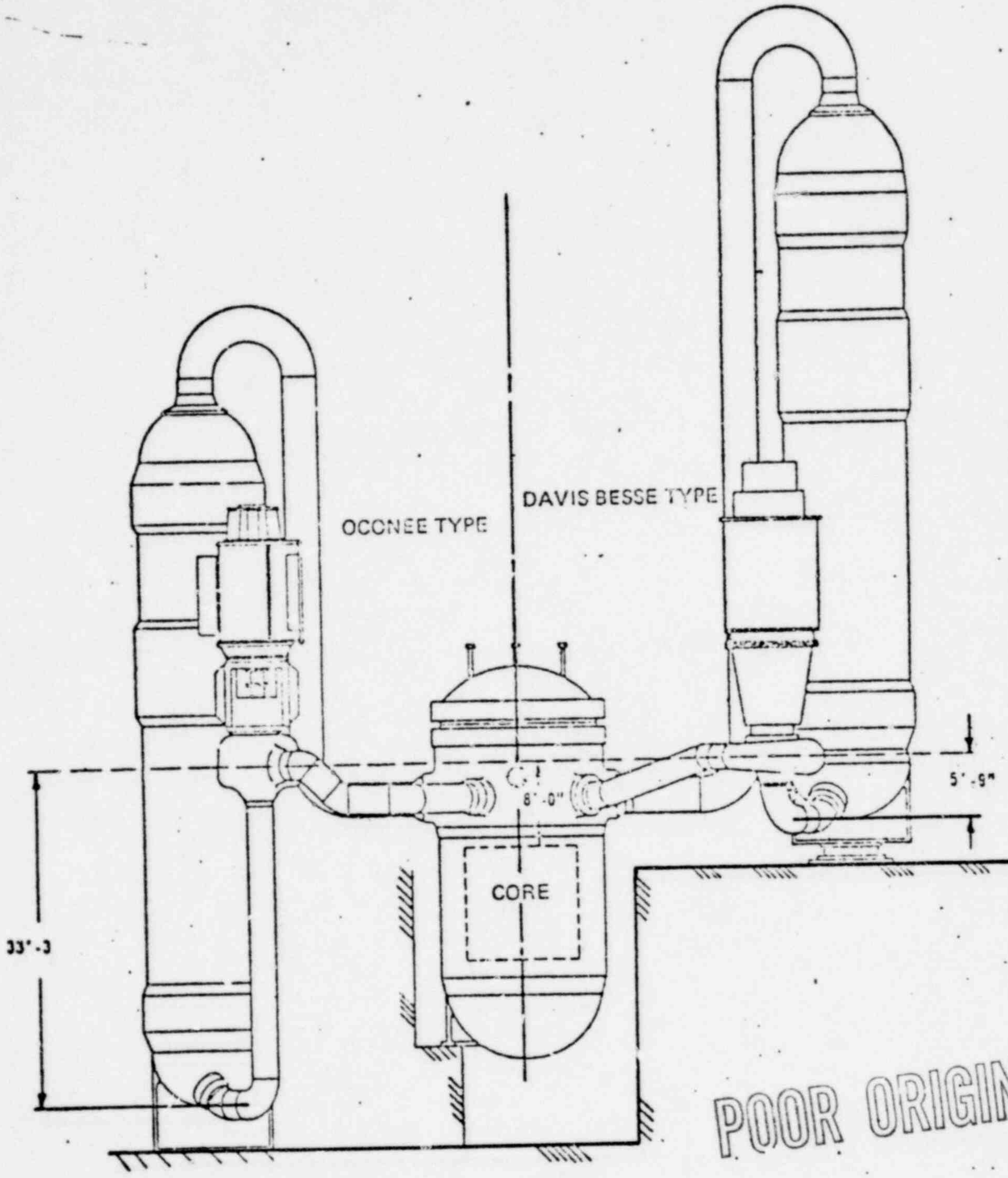
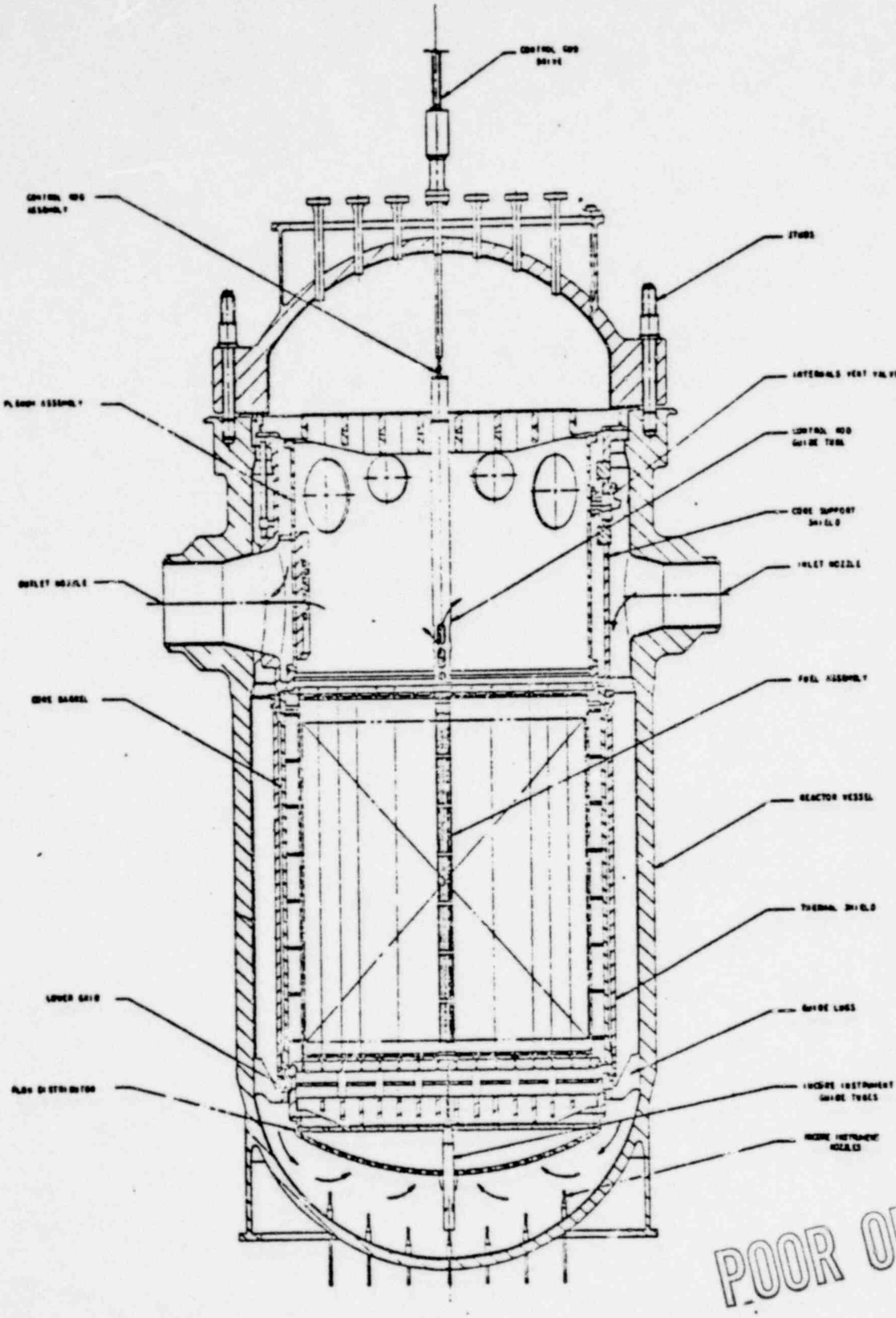


FIGURE 3.1-5 COMPARISON OF LOOP CONFIGURATION



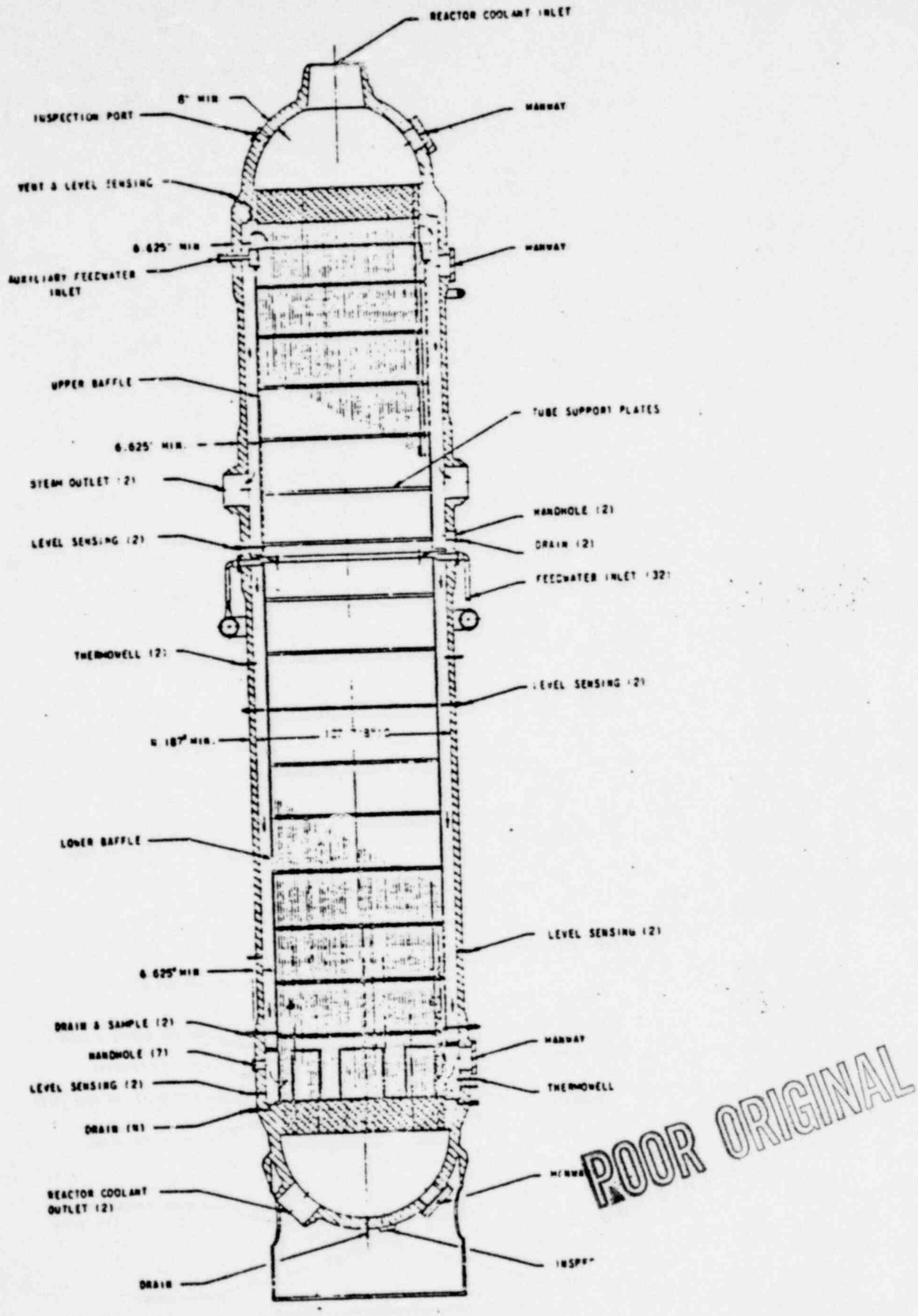
NOTE: Surveillance Specimen Holder Tube Not Shown

REACTOR VESSEL & INTERNALS-GENERAL ARRANGEMENT

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

AM. 50 (12-8-76)

FIGURE 3.1-6

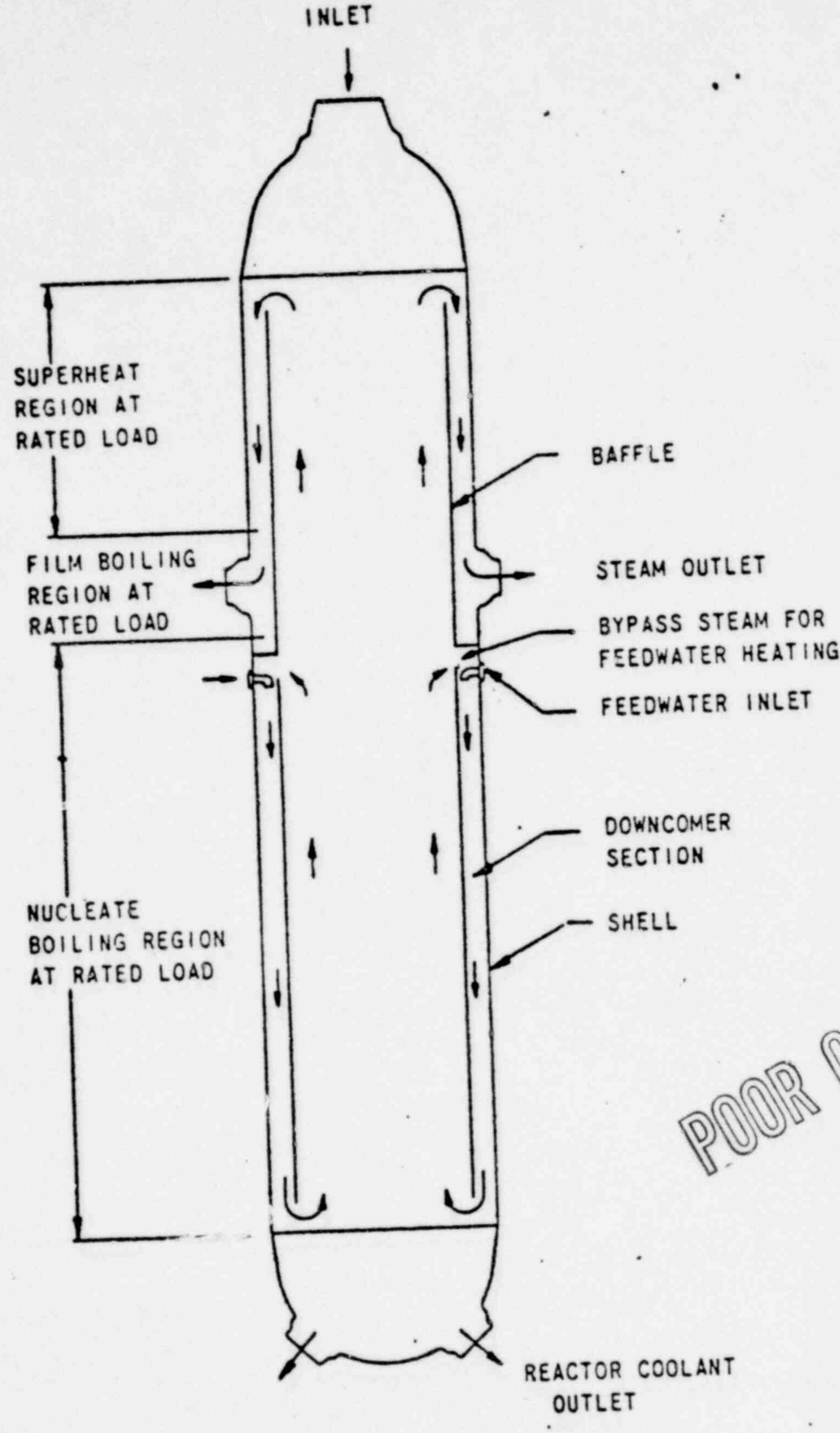


STEAM GENERATOR OUTLINE

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

1215 181

FIGURE 3.1-7

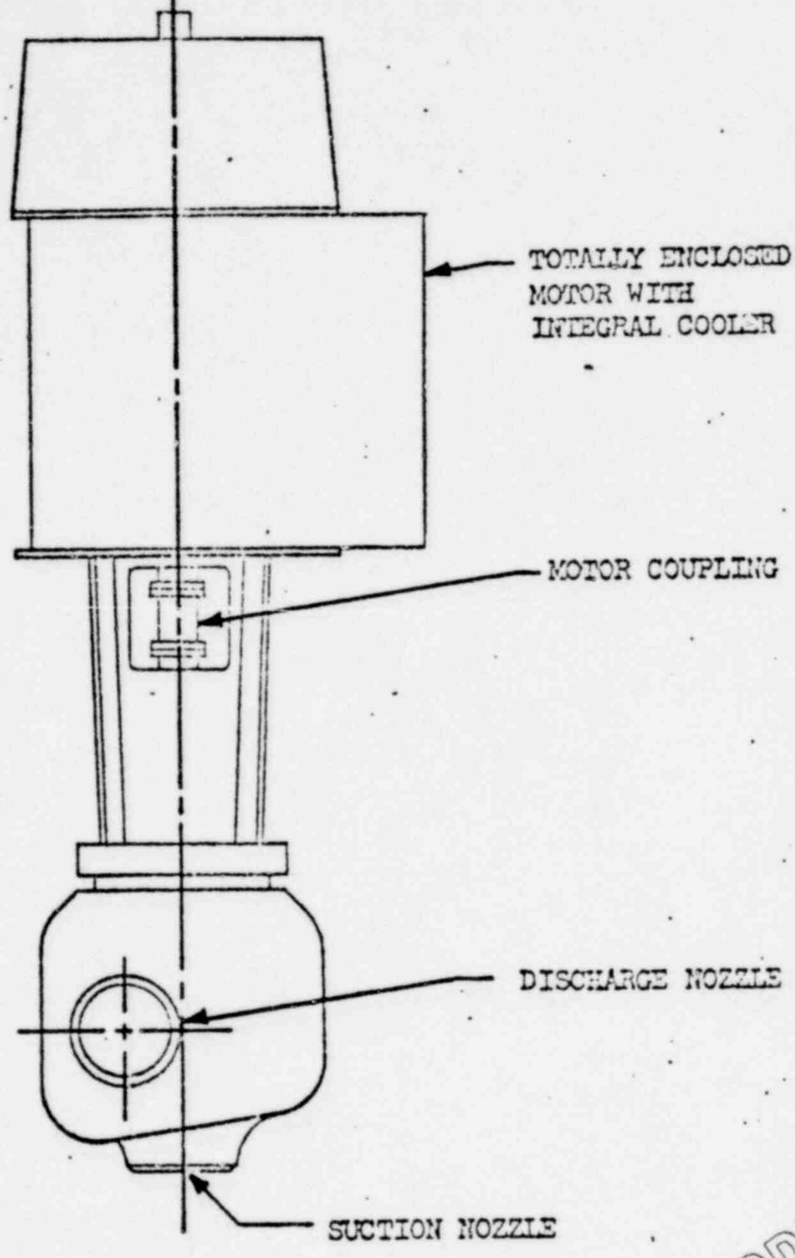


STEAM GENERATOR HEATING REGIONS

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

1215 182

FIGURE 3.1-8



REACTOR COOLANT PUMP

FROM UNIT 1 PSAR

FSAR THREE MILE ISLAND NUCLEAR STATION

FIGURE 3.1-9

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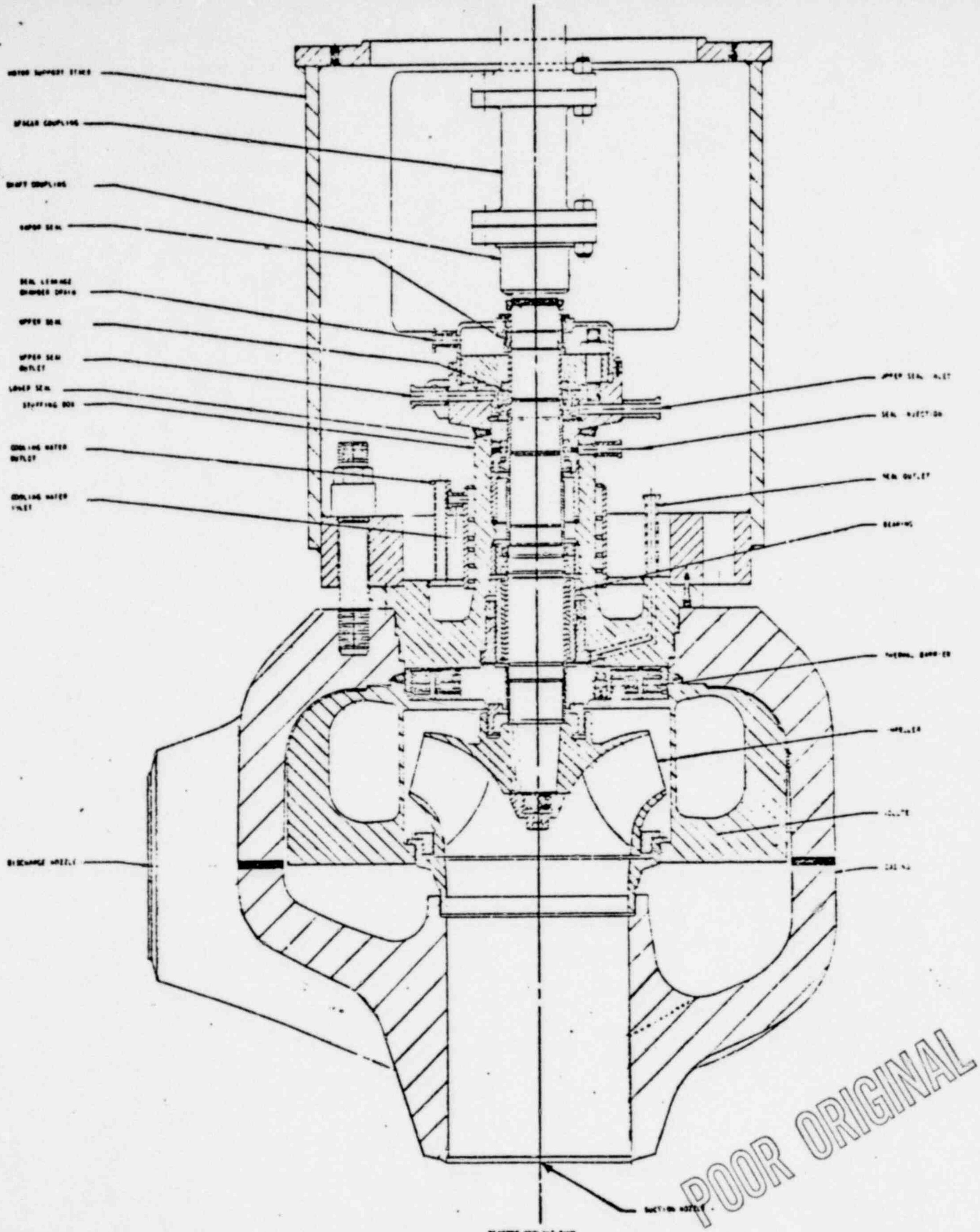

REACTOR COOLANT PUMP

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

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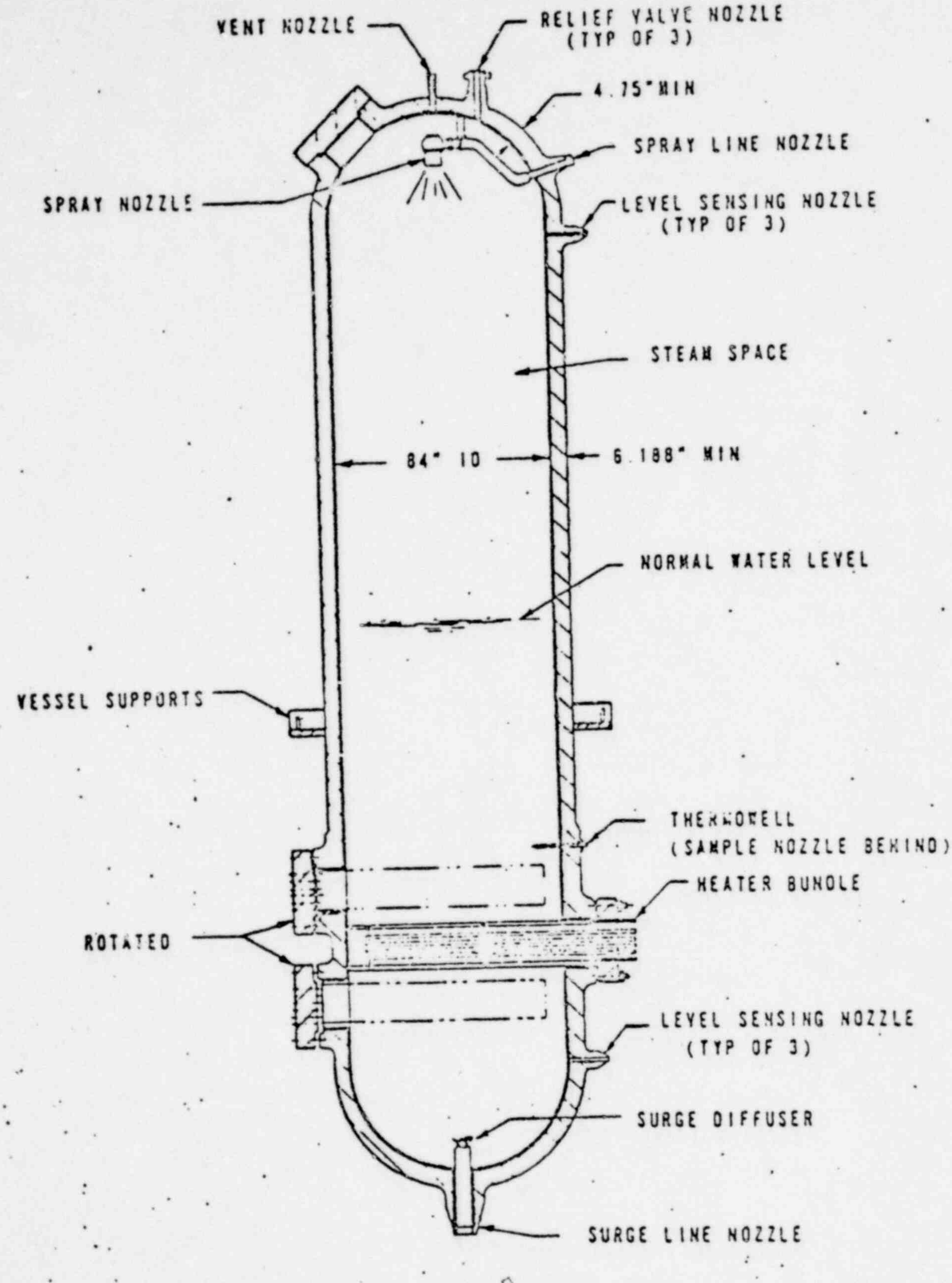
FIGURE 3.1-10



POOR ORIGINAL

PRESSURIZER

FSAR THREE MILE ISLAND NUCLEAR STATION UNIT 2

FIGURE 3.1-11

1215 185

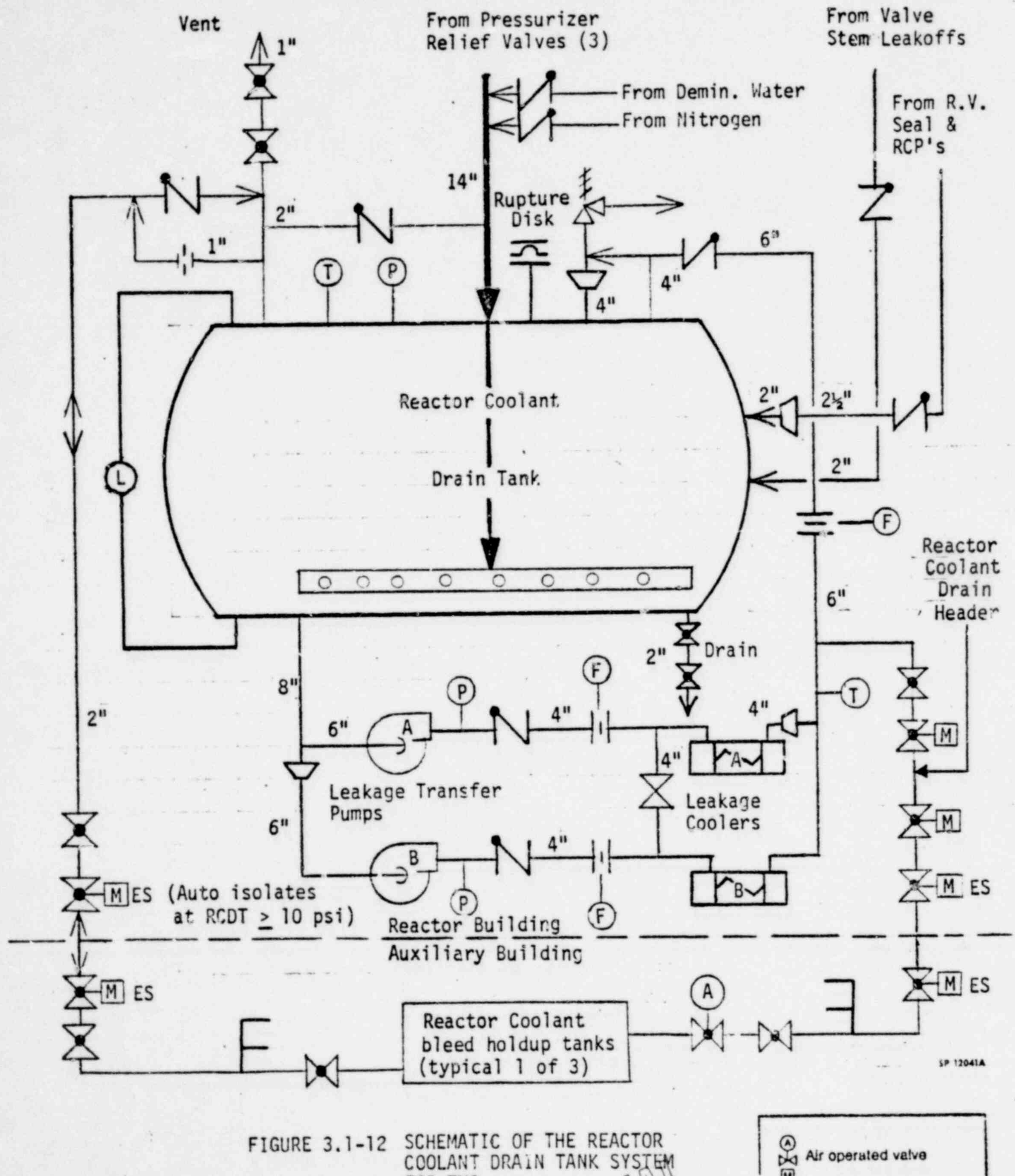


FIGURE 3.1-12 SCHEMATIC OF THE REACTOR COOLANT DRAIN TANK SYSTEM FOR TMI

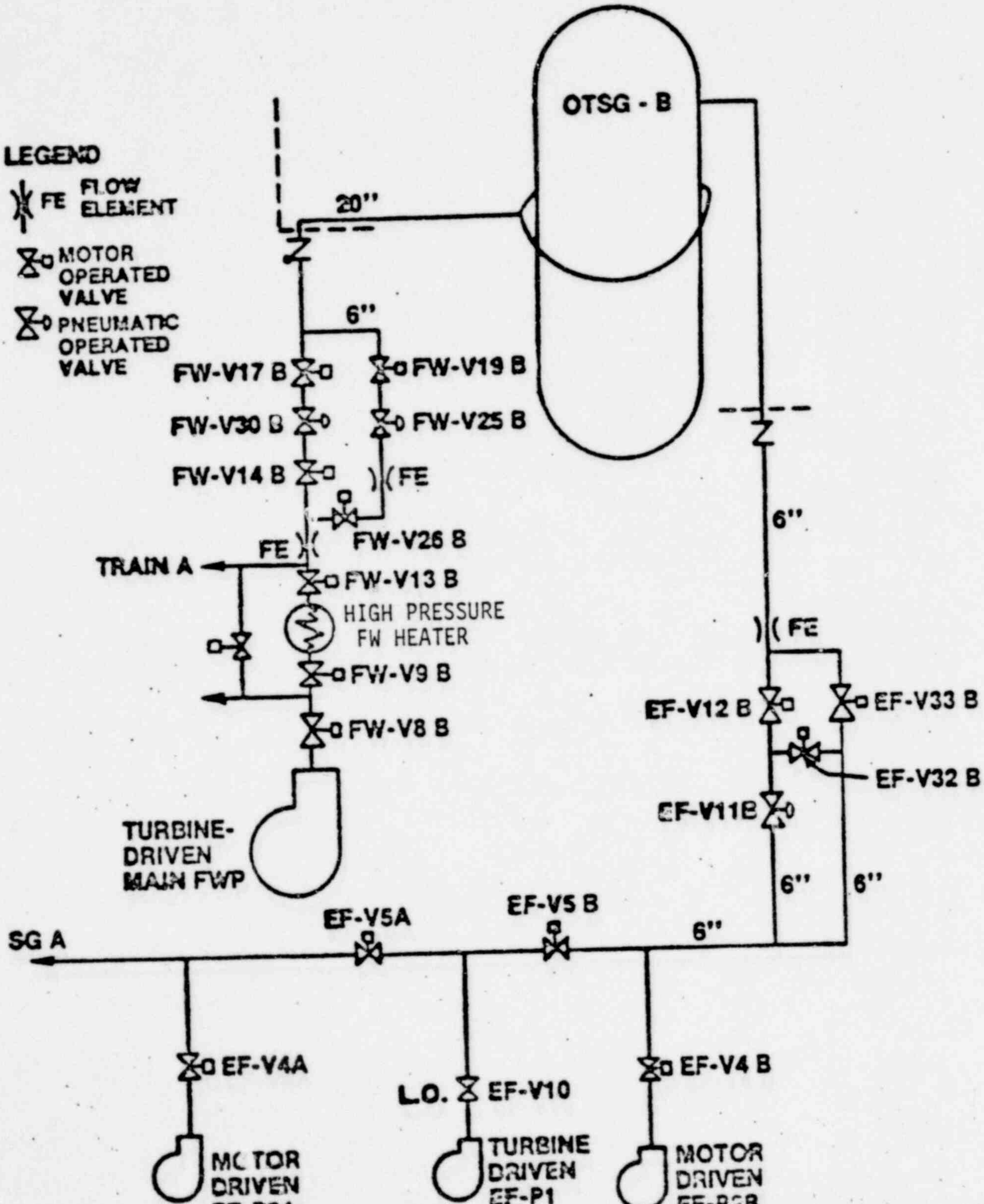


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FIGURE 3.1-13 TMI-2 MAIN & AUX. FEEDWATER - TRAIN B ONLY

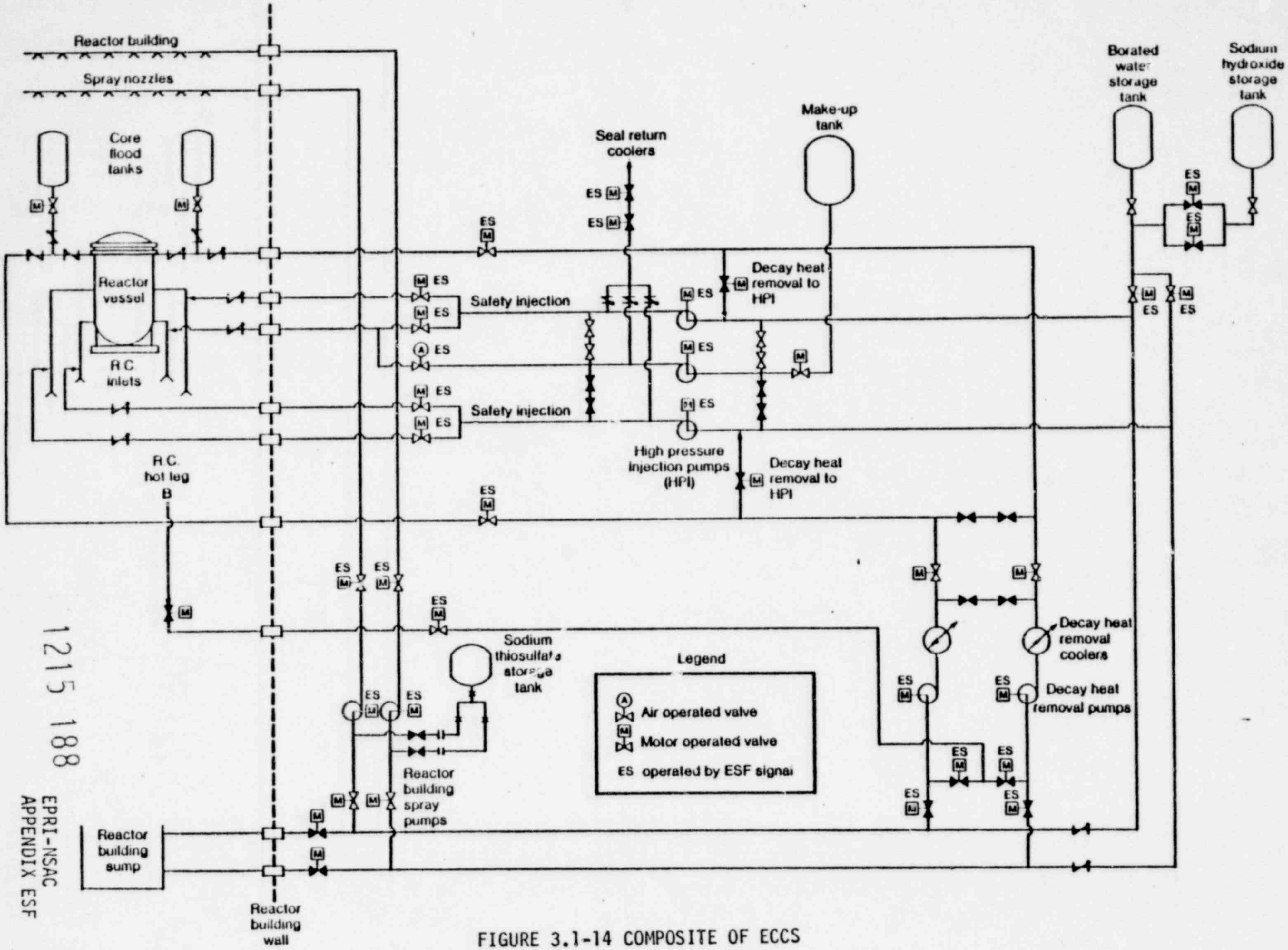

FIGURE 3.1-14 COMPOSITE OF ECCS

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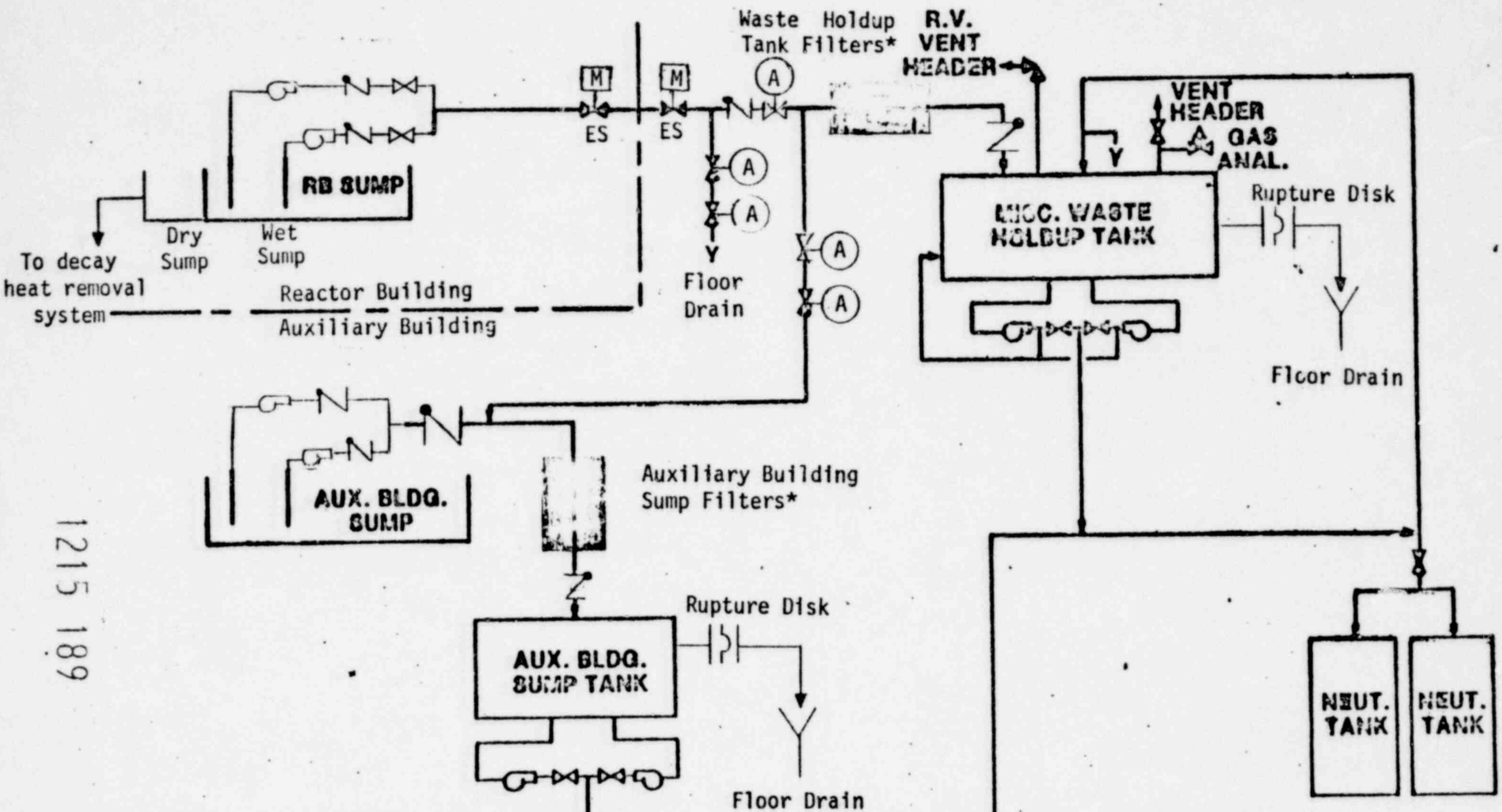
EPRI-NSAC
APPENDIX ESF



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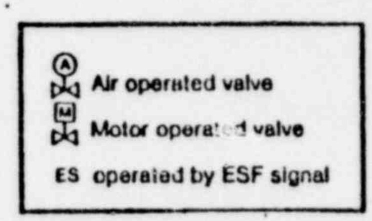
*Two Filters are arranged in parallel with individual isolation and a bypass.

FIGURE 3.1-15 CONTAINMENT SUMP PUMP



3.2 GENERAL DESCRIPTION OF THE POINT BEACH NUCLEAR PLANT

The Point Beach Nuclear Plant, Units 1 and 2, consists of two essentially identical pressurized water reactors designed by Westinghouse Electric Corporation and schematically represented in Figure 3.2-1. Each unit has a rated thermal output of 1518.5 Mw and generates 523.8 Mw of gross electrical power. Point Beach Unit 1 has been in commercial operation since December 1970. Unit 2 went into commercial operation in October 1972. Together the units have generated more than 54 billion kilowatt hours of electrical energy.

For each unit, the nuclear steam supply system consists of a pressurized water reactor, two closed reactor coolant loops and associated fluid systems. The reactor coolant loops are connected to the reactor vessel in parallel, each loop containing a reactor coolant pump and a steam generator as shown in Figure 3.2-2. A pressurizer is connected to one of the loops. The reactor core is composed of 121 assemblies. Each fuel assembly consists of uranium oxide fuel pellets enclosed in zircaloy tubes arranged in a 14x14 matrix.

The reactor is controlled by a coordinated combination of boron dissolved in the primary coolant and mechanically operated control rods. The control system is designed to sustain reactor operation following a step net load rejection of 50% power. A turbine trip from above 50% power will result in an automatic reactor trip. The layout of the major components is shown in the plan view of the containment (Figure 3.2-3). Relative elevations of the reactor coolant pumps, steam generators, and pressurizer can be seen in Figure 3.2-4. The reactor vessel and internals are shown in Figure 3.2-5. Reactor coolant enters the vessel through the inlet nozzles in a plane just below the vessel flange and above the core. The coolant flows downward through the annular space between the vessel wall and the core barrel into a plenum at the bottom of the vessel. Here it reverses direction and flows upward through the reactor core.

The coolant mixes in the upper plenum and then flows out of the vessel through two exit nozzles located on the same plane as the inlet nozzles. The austenitic stainless steel reactor coolant piping and fittings which make up the loops are 29-inch inside diameter in the hot legs, 27-1/2 inch inside diameter in the cold legs, and 31-inch inside diameter in the crossover legs between the steam generator and reactor coolant pump.

A chemical and volume control system is provided to charge the reactor coolant system, allow for volume changes, add makeup water, provide reactor coolant pump seal water, purify reactor coolant water, and provide chemicals for corrosion inhibition and reactor control. Other auxiliary systems cool system components, remove residual heat when the reactor is shut down, sample the coolant, provide for emergency safety injection and vent and drain the reactor coolant system. The chemical and volume control system consists of three positive displacement pumps, regenerative and non-regenerative heat exchangers, demineralizers and filters, flow control orifices, the various isolation and control valves, and flow, pressure, and temperature instrumentation.

The steam generators, two per unit, are inverted vertical U-tube type heat exchangers utilizing Inconel tubes as shown in Figure 3.2-6. Integral separating equipment reduces the moisture content of the steam at the steam generator outlet to one quarter of a percent or less. The reactor coolant pumps are vertical, single stage, centrifugal pumps equipped with controlled leakage shaft seals, as shown in Figure 3.2-7. There is one pump per loop, or two per unit.

Pressure in the reactor coolant system is controlled by electric heaters in the pressurizer. The pressurizer is constructed of carbon steel with the internal surface clad with stainless steel is shown in Figure 3.2-8. The 10-inch pressurizer surge line is connected to the loop B hot leg. The pressurizer spray is taken from the A and B cold legs or can be supplied by the auxiliary charging line. The reactor coolant system is protected from overpressurization by two power operated relief valves and two code safety valves at the top of the pressurizer off the steam space. These relief valves discharge into a pressurizer relief tank. The pressurizer relief tank is protected from overpressurization by a rupture disc and the spray and drain system. The pressurizer and relief tank are shown in Figure 3.2-9.

The steam and power conversion system for each unit of the Point Beach Nuclear Plant is schematically shown in Figure 3.2-10. It consists of a three element tandem-compound, 1800 rpm turbine driving a 582,000 KVA, 3 phase, hydrogen innercooled main generator. Four combination moisture separator reheater units are employed to dry and superheat the steam between the high and low pressure turbine cylinders The turbine exhaust steam is condensed in a single pass deaerating, radial flow surface condenser. The condensers are cooled by an open cycle circulating water system supplied from Lake Michigan.

Both units are provided with two 50% capacity condensate pumps and two 50% capacity motor-driven main feedwater pumps. Five stages of feedwater heaters are provided. The auxiliary feedwater system supplies high pressure feedwater to the steam generators in order to maintain a water inventory for removal of heat from the reactor coolant system (RCS) by secondary side steam release when the main feedwater system is not operating. The pressure generated by the pumps is sufficient to deliver feedwater into the steam generators at safety valve pressure. Redundant water supplies are provided by using two pumping systems. The auxiliary feedwater system is schematically represented in Figure 3.2-12. One system utilizes a steam turbine driven pump, capable of being supplied with the steam from either or both steam generators. This system supplies 400 gpm of feedwater or 200 gpm to each steam generator. The drive is a single stage turbine, capable of quick starts from cold standby and is directly connected to the pump. The turbine is started by opening either one or both of the isolation valves between the turbine supply steam header and the main steam lines. There is a single system of this type dedicated to each unit and they are completely independent. The other system is common to both units and utilizes two similar motor driven pumps, each capable of obtaining its electrical power from the plant emergency diesel generators. This system has a total capacity of 400 gpm of feedwater. Each pump has a 200 gpm capability and can supply feedwater to one steam generator in either or both units independent of the other train.

The water supply for the auxiliary feedwater system is redundant. The main source is by gravity feed from two 45,000 gallon condensate storage tanks. There is one tank for each unit and either or both can supply feedwater to the four pumping systems. The backup supply is taken from Lake Michigan via the

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plant Service Water System. Its six pumps are powered from the diesel generators if station power is lost. Each motor driven service water centrifugal pump has an accident capacity of 5500 gpm. Two service water pumps are connected to separate 480v buses, one per bus, while the four remaining pumps are connected to two separate 480v buses, two per bus. Two of the six pumps are capable of carrying the required normal cooling load for the two units at their normal capacity of 6800 gpm.

The main feedwater system has a number of specific design features and alarms to minimize the need for actuation of the auxiliary feedwater system, to alert the reactor operator, and to minimize the severity of any transient. Each of the two half-capacity main feedwater pumps has a minimum flow control system which recirculates a minimum of 500 gpm of flow through the pump to the main condensor during low system flow conditions to prevent overheating of the pump. An automatic bypass is provided around the low pressure feedwater heaters to ensure sufficient suction pressure for the main feedwater pumps during a transient when flashing may occur in the heater drain tank and affect the drain pump performance. Sustained low suction pressure sounds an alarm on the main control board and trips the main feedwater pumps after two minutes. The high pressure feedwater heaters have a manual bypass valve which can be used to bypass feedwater flow around those heaters in an emergency. The main feedwater regulating valves each have a bypass valve controlled remotely from the main control board to further increase the reliability of the main feedwater system.

The Engineered Safety Features provided for the plant have redundancy of components and power sources. Under the conditions of a hypothetical LOCA the system can, even when operating with partial effectiveness (following single failure of an active component), keep the exposure of the public below the limits of 10 CFR 100. These systems are summarized as follows:

A. The containment system provides a highly reliable, essentially leaktight barrier against the escape of fission products.

B. The safety injection and emergency core cooling system provides borated water to cool the core by injection into the cold legs of the reactor coolant loops. The system uses two passive accumulators (Figure 3.2-13) and two high pressure safety injection pumps. The high pressure safety injection may also be directed over the top of the core via injection through core deluge nozzles. The two residual heat removal pumps also function as low pressure safety injection pumps to provide high volume/low pressure injection into the reactor coolant system via the core deluge nozzles. This system is shown in Figure 3.2-14.

C. The containment air recirculation cooling system provides a dynamic heat sink to cool the containment atmosphere under LOCA conditions.

D. The containment spray system provides a spray of cooled, chemically treated, borated water to the containment atmosphere to provide iodine removal capacity and to back up the containment air recirculation cooling system.

The major structures on the Point Beach Nuclear Plant site include two reactor containments, one per unit, and the following which are shared: auxiliary building, turbine building, pumphouse and service building. A common control room for both units is located in and is an integral part of the turbine building.

Emergency electrical power is provided by two on-site diesel generator sets. Each diesel generator set has sufficient capacity to supply the ESF load for the design basis accident in one unit while allowing the second unit to be placed in a safe shutdown condition even during a complete loss of offsite electrical power condition.

Section 3.3 of this report provides a comparison of plant features between the Point Beach Nuclear Plant and Three Mile Island. Specific parameter values for a variety of equipment at each site may be found in Tables 3.3-1 and -2.

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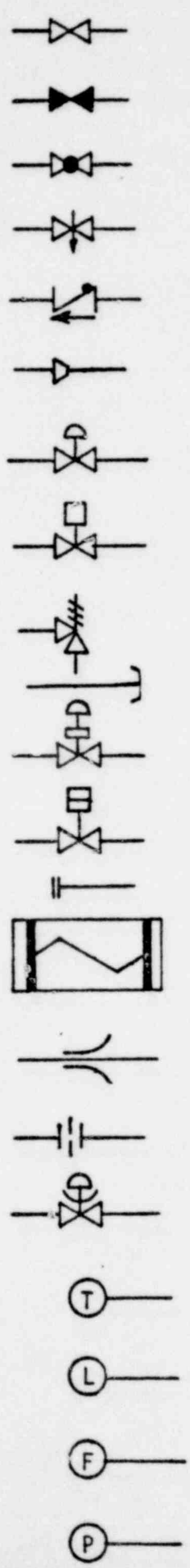
KEY TO FIGURES



NORMALLY OPEN | GATE VALVE

NORMALLY CLOSED | GATE VALVE

GLOBE VALVE

NEEDLE VALVE

CHECK VALVE

REDUCER

AIR DIAPHRAGM OPERATOR

ELECTRICAL MOTOR OPERATOR

SAFETY RELIEF VALVE

CAPPED PIPE

PROPORTIONAL CONTROLLED AIR OPERATOR

PISTON OPERATOR

BLIND FLANGE

HEAT EXCHANGER

FLOW RESTRICTOR

FLOW RESTRICTION ORIFICE

SAUNDERS PATENT DIAPHRAGM VALVE

TEMPERATURE INDICATOR

LEVEL INDICATOR

FLOW INDICATOR

PRESSURE INDICATOR

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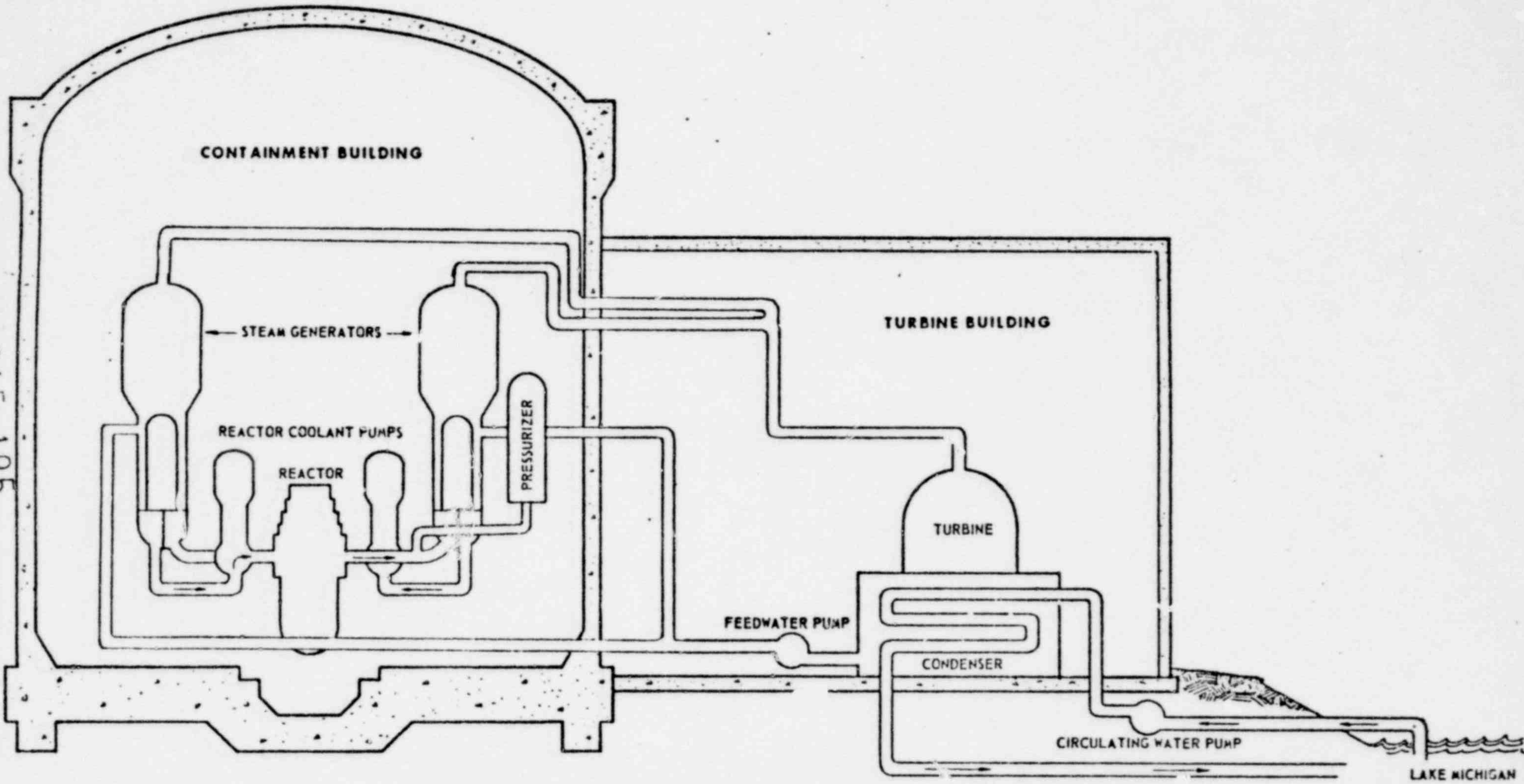

FIGURE 3.2-1 POINT BEACH NUCLEAR PLANT

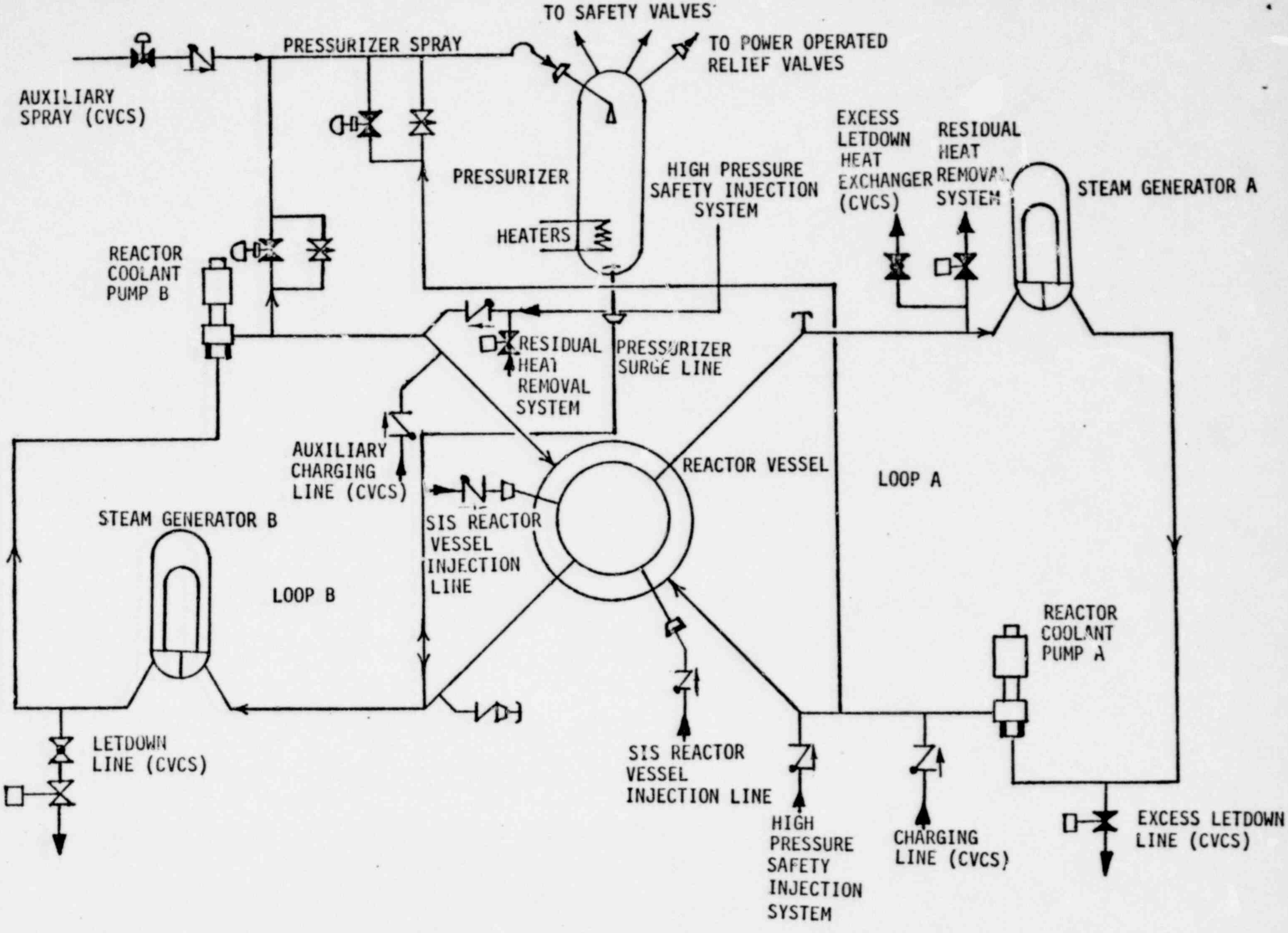

FIGURE 3.2-2 PBNP REACTOR COOLANT SYSTEM FLOW DIAGRAM

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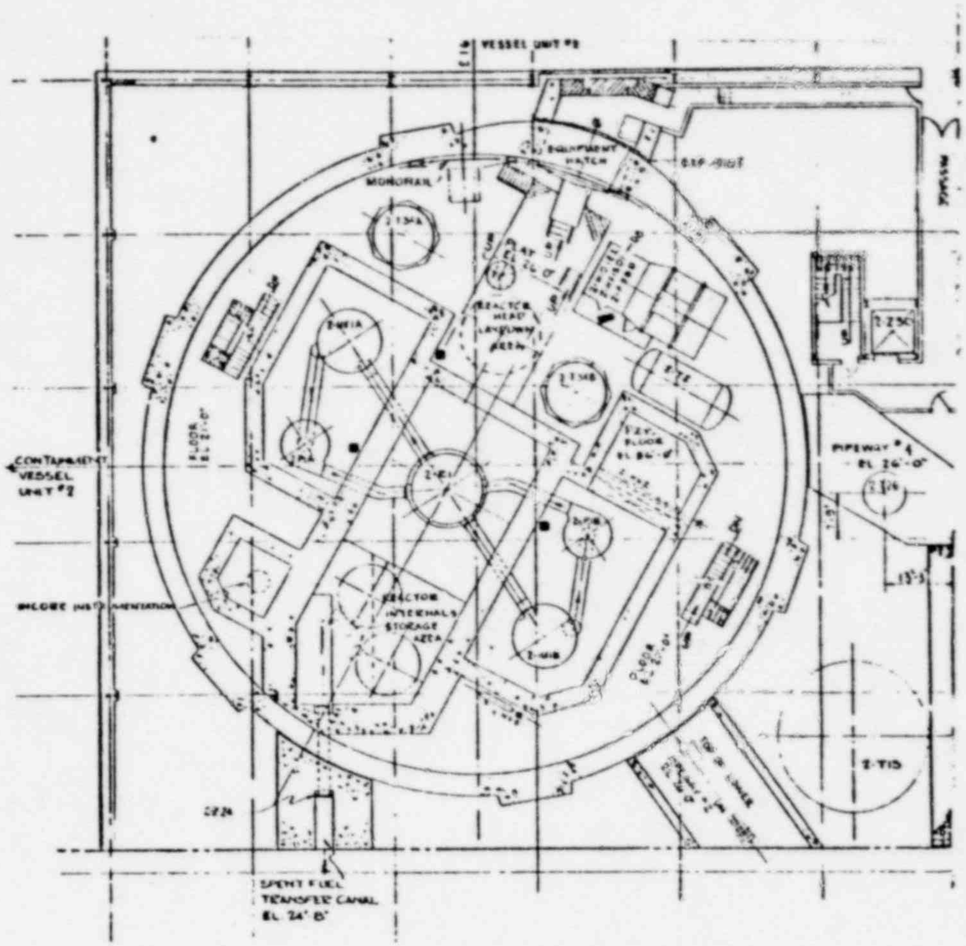

FIGURE 3.2-3 PBNP CONTAINMENT - PLAN VIEW

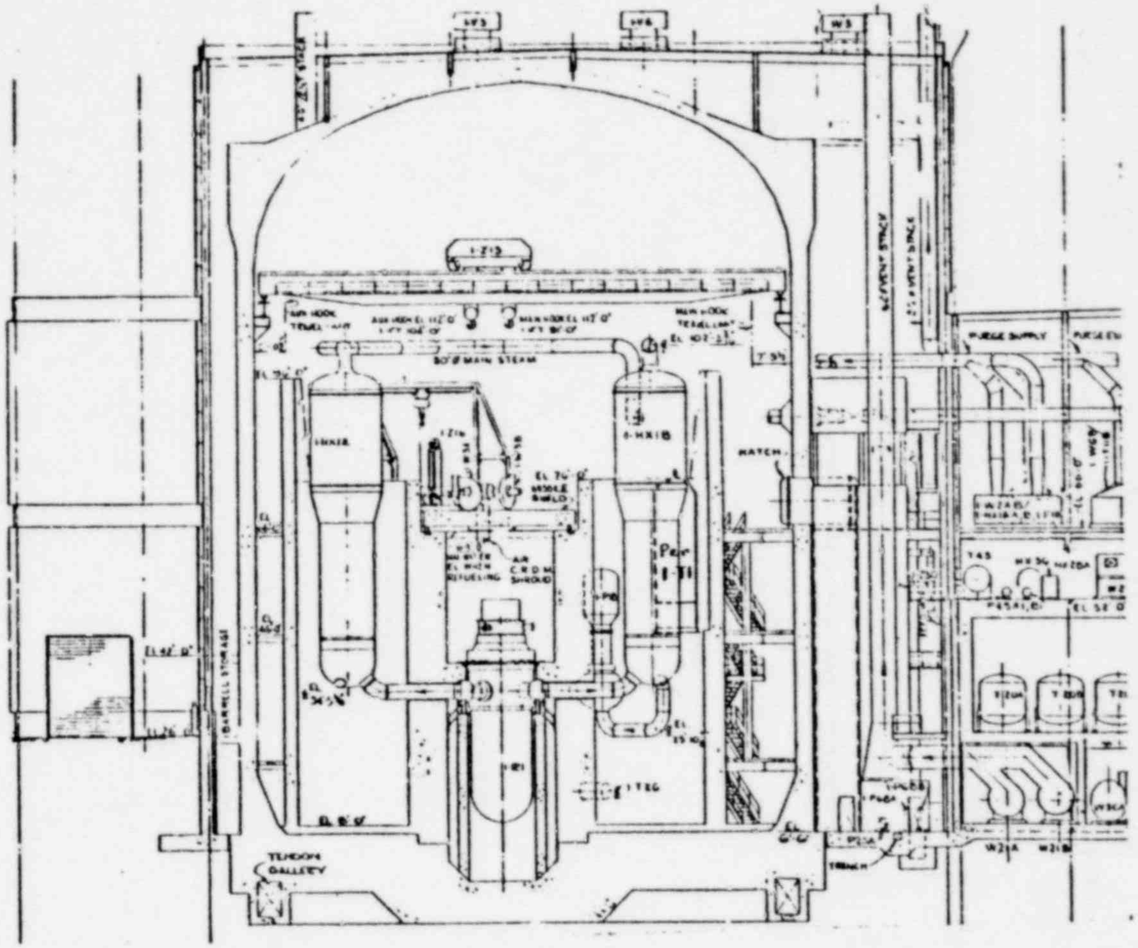

FIGURE 3.2-4 PBNP CONTAINMENT - ELEVATION

1215 198

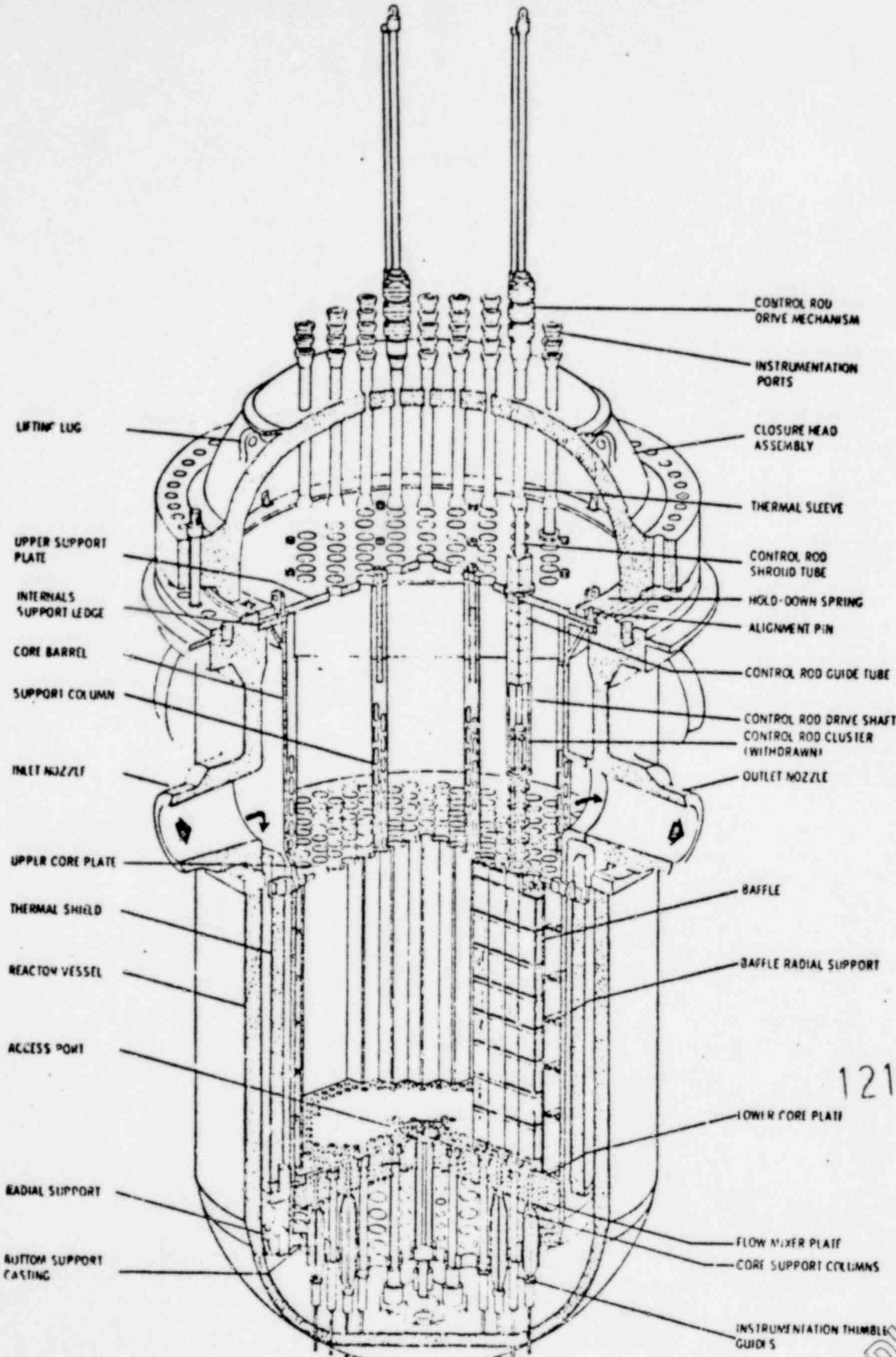

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FIGURE 3.2-5 PBNP REACTOR VESSEL AND INTERNALS

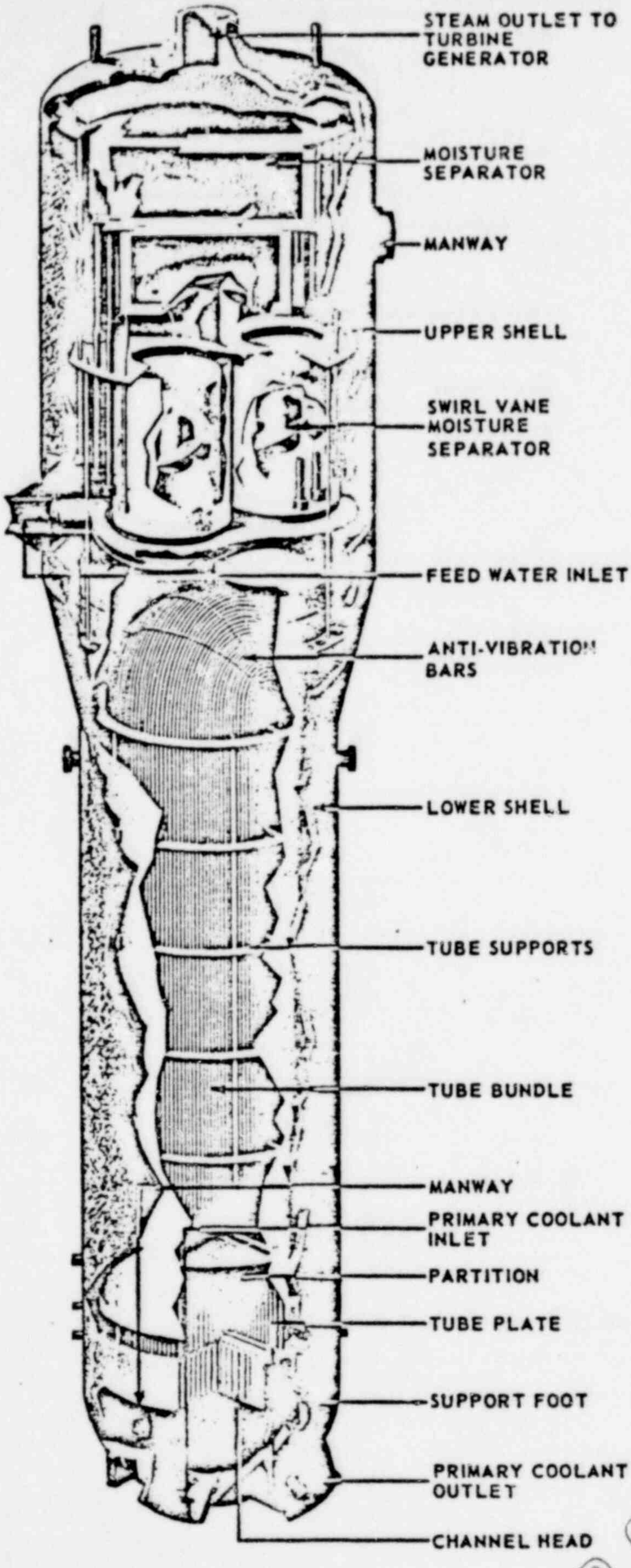

FIGURE 3.2-6 PBNP STEAM GENERATOR

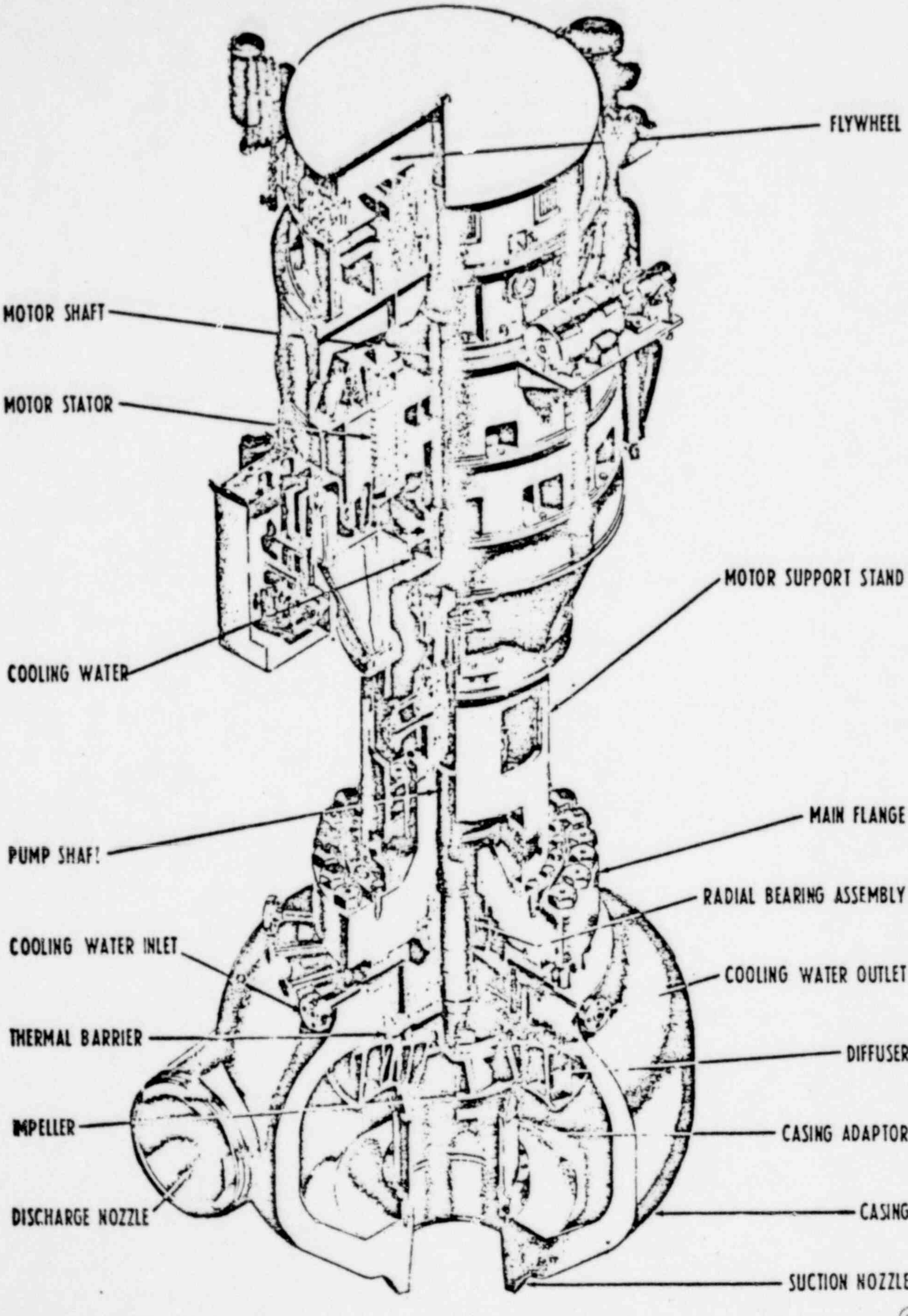

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FIGURE 3.2-7 PBNP REACTOR COOLANT PUMP

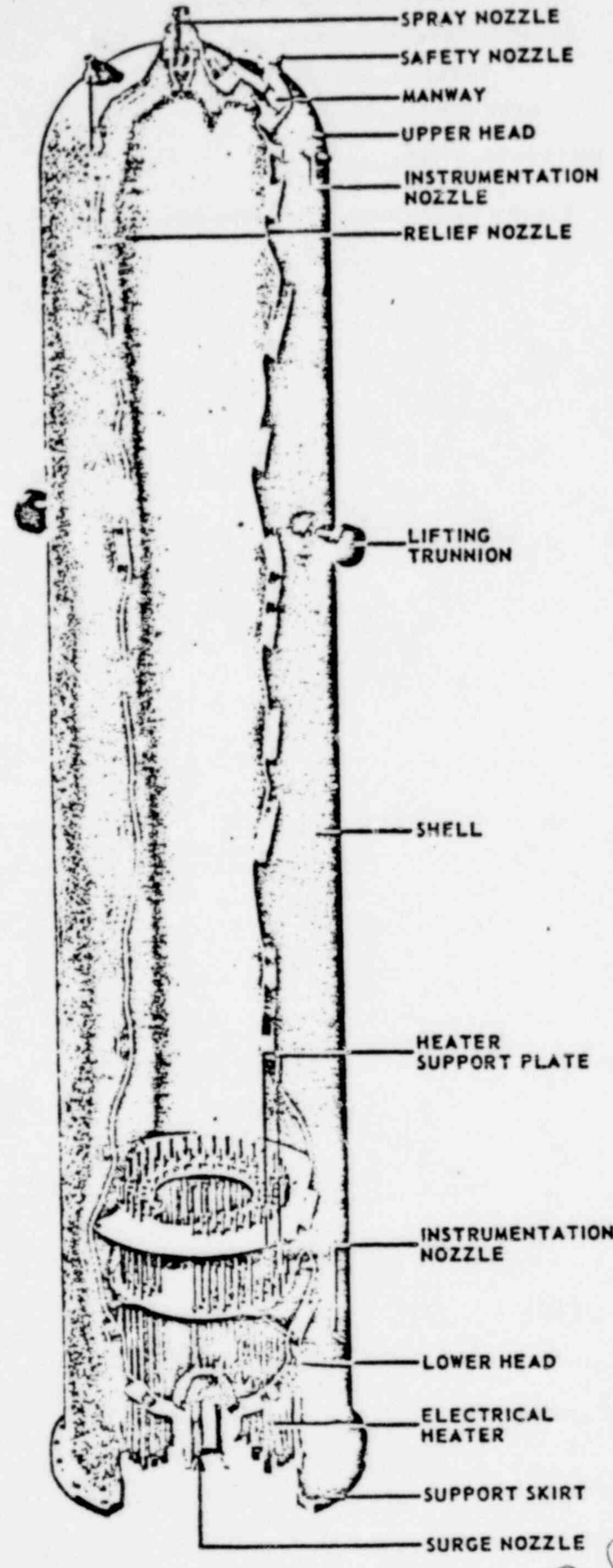

FIGURE 3.2-8 PBNP PRESSURIZER

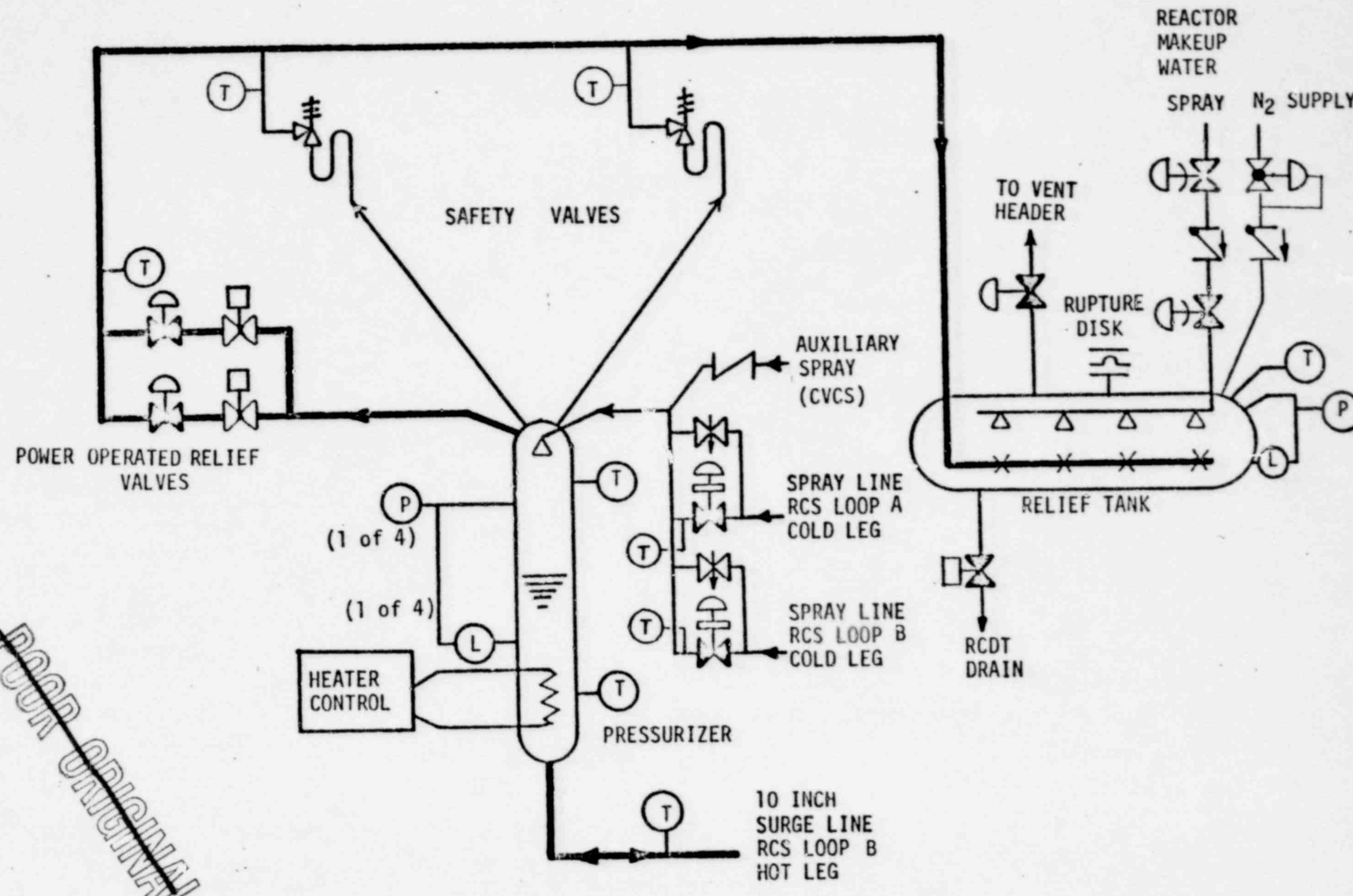

FIGURE 3.2-9 PBNP PRESSURIZER AND RELIEF TANK

POOR ORIGINAL

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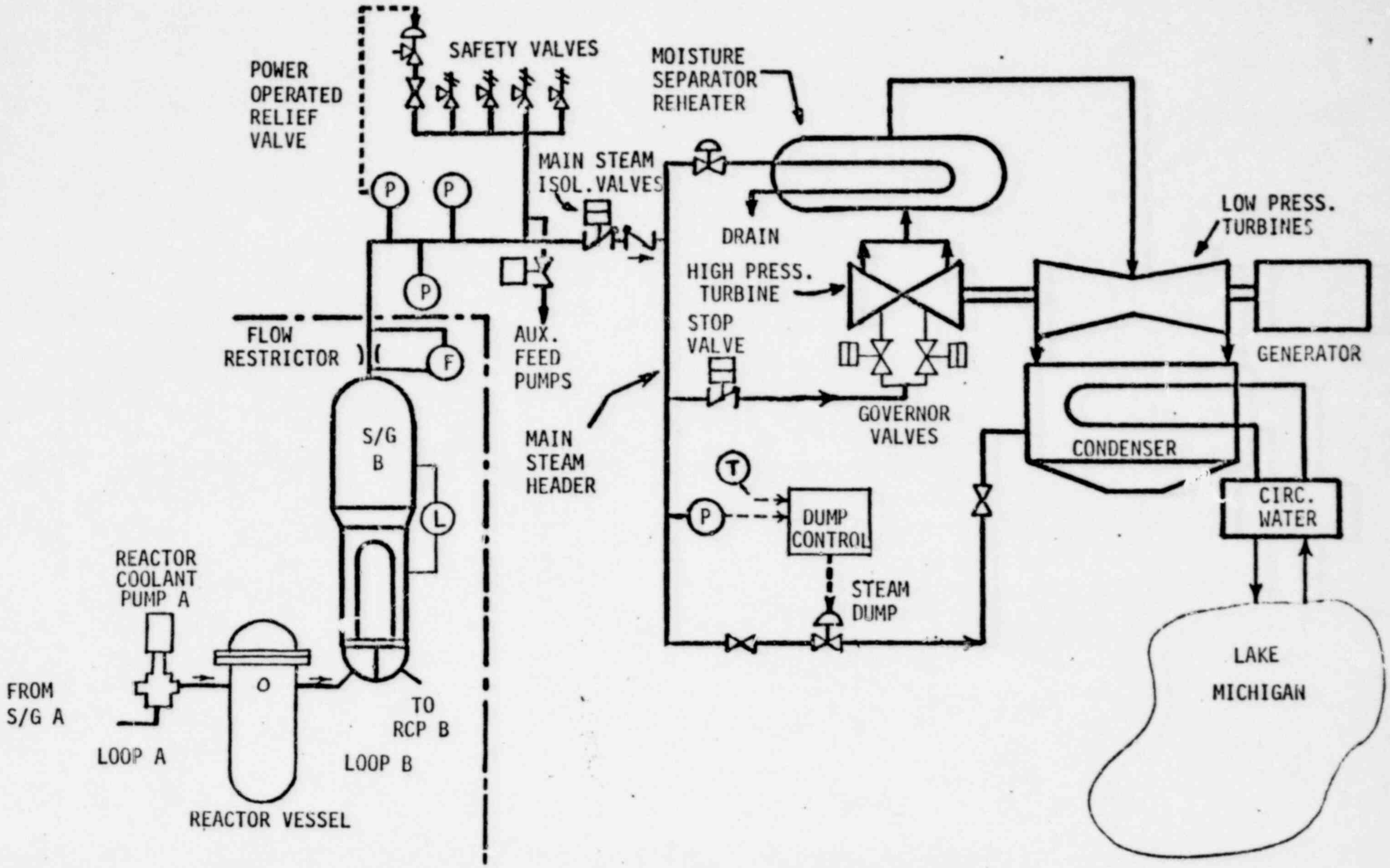

FIGURE 3.2-10 PBNP STEAM AND POWER CONVERSION SYSTEM SCHEMATIC

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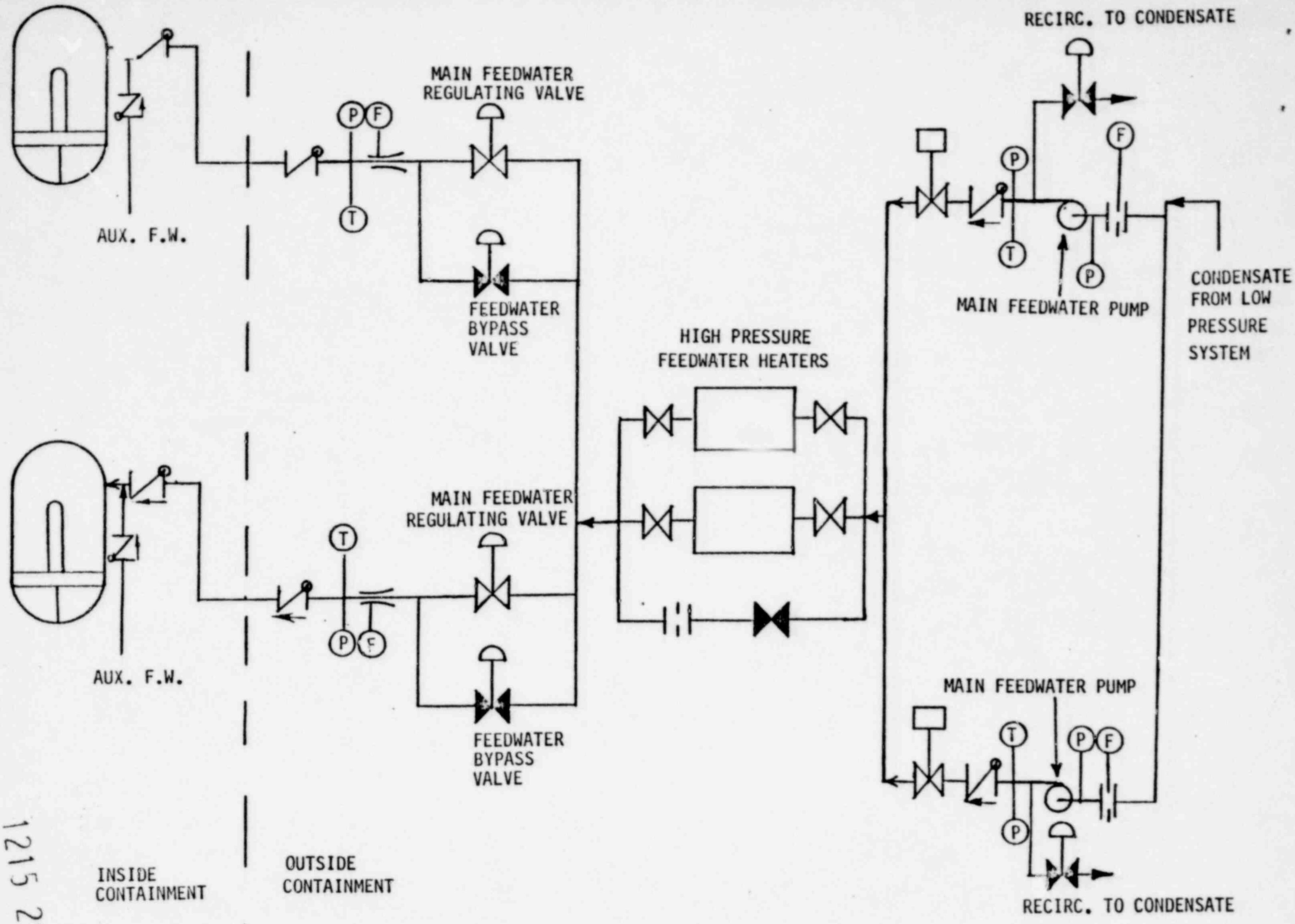

FIGURE 3.2-11 PBNP MAIN FEEDWATER SCHEMATIC

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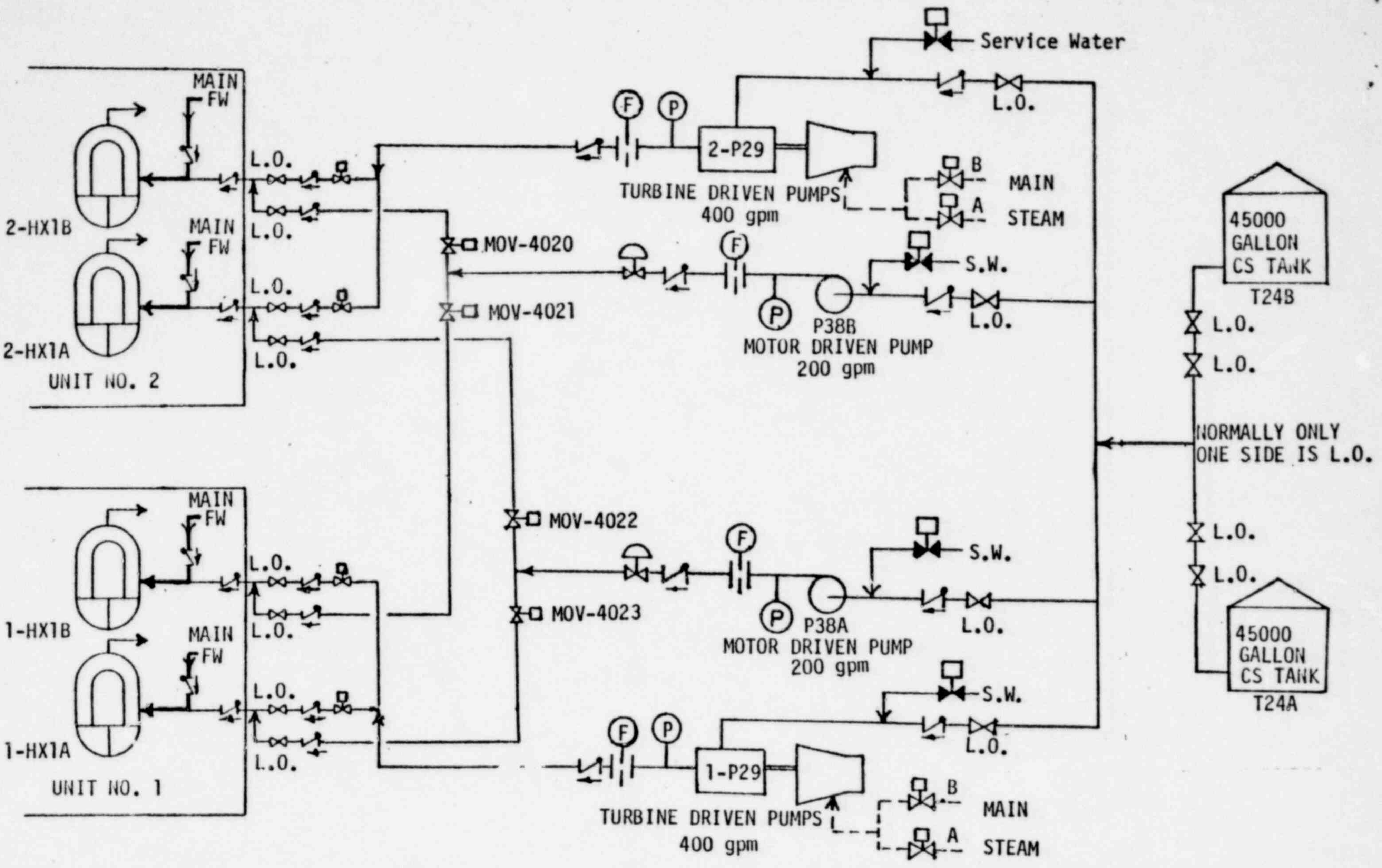

L.O. = LOCKED OPEN

FIGURE 3.2-12 PBNP AUXILIARY FEEDWATER SCHEMATIC

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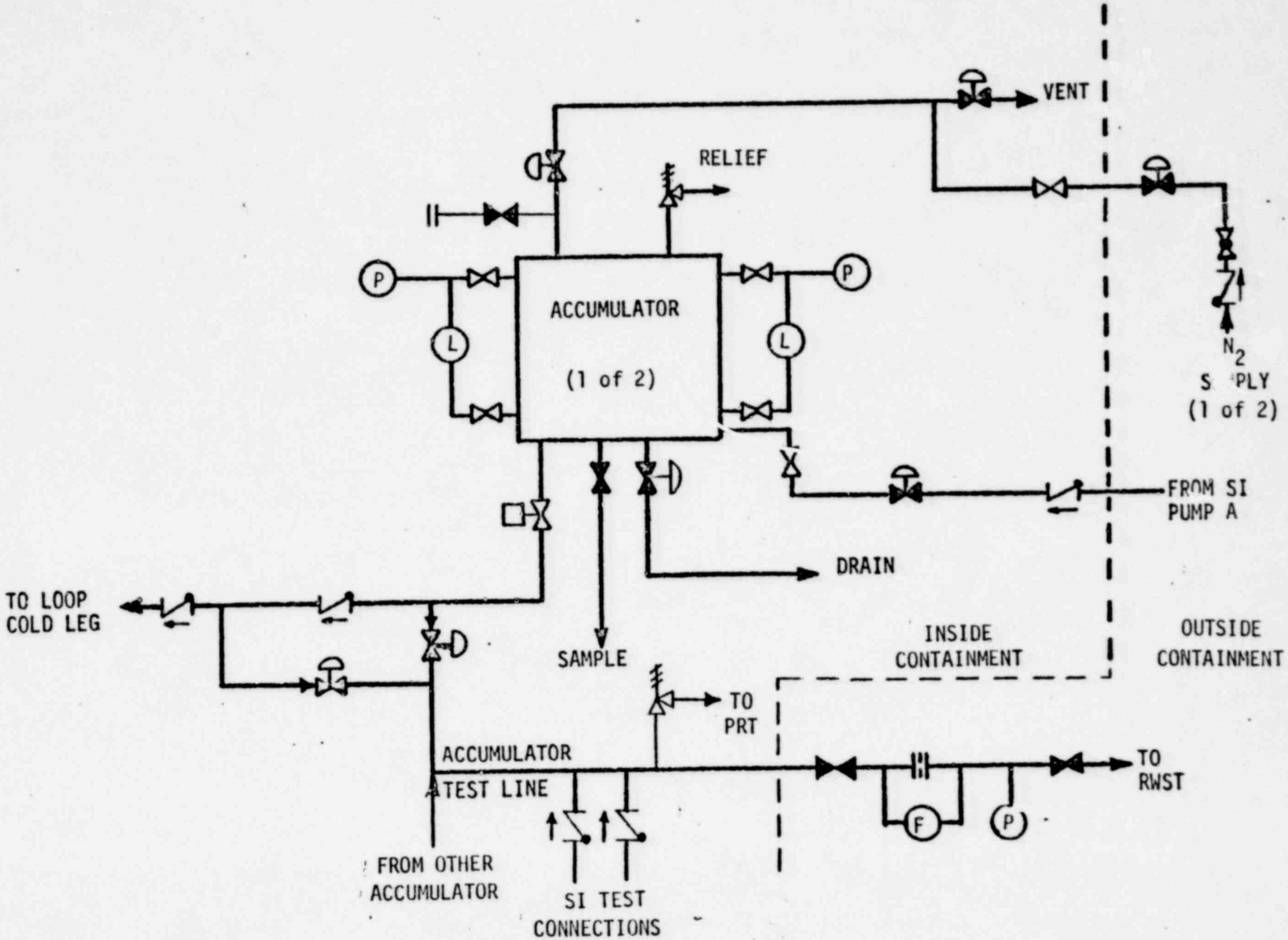

FIGURE 3.2-13 PBNP ACCUMULATOR SYSTEM SCHEMATIC

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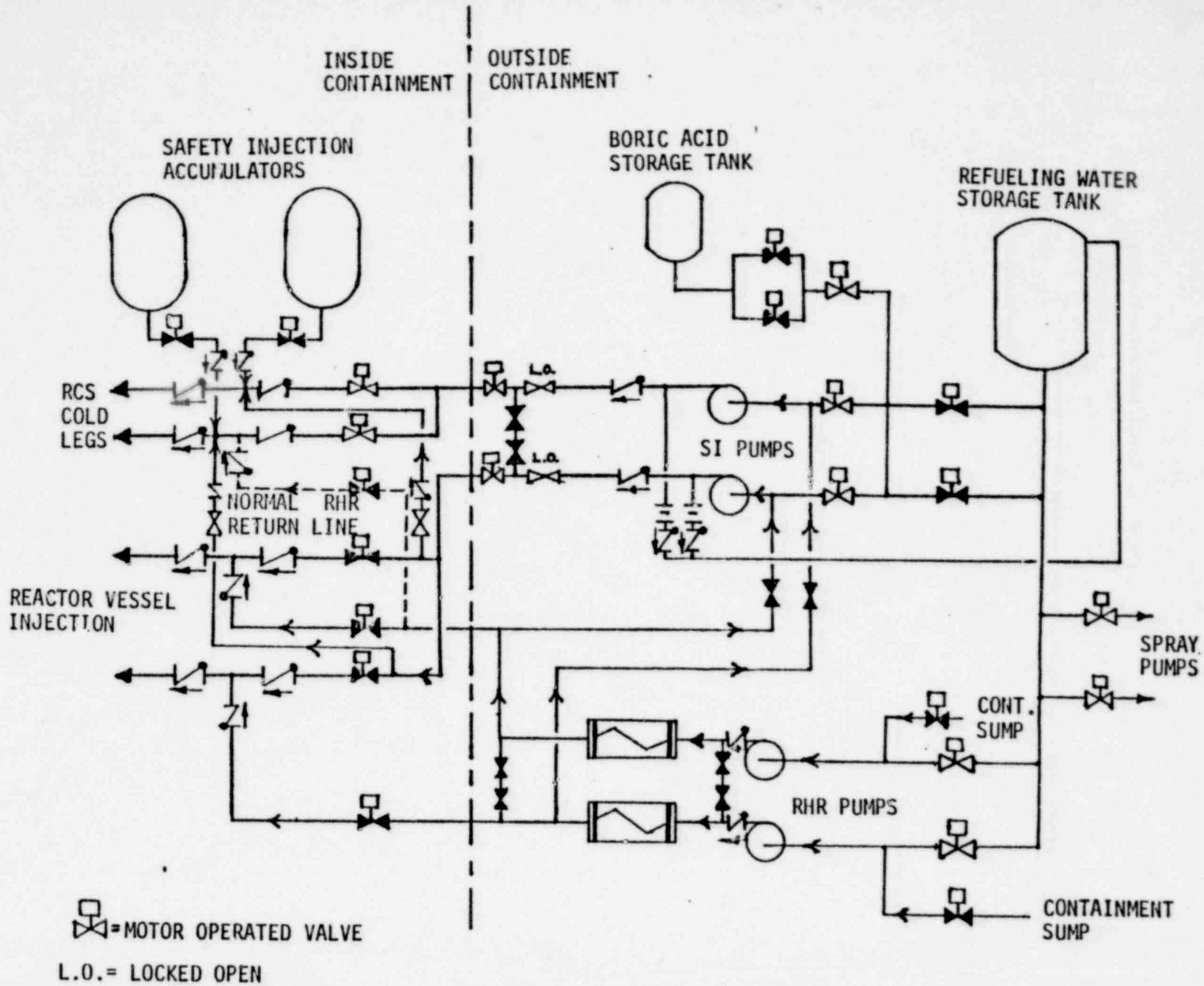

FIGURE 3.2-14 PBNP SAFETY INJECTION SYSTEM SCHEMATIC

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3.3 SYSTEM, EQUIPMENT, AND PARAMETER COMPARISONS

A comparison of the Point Beach Nuclear Plant and Three Mile Island discloses major differences in the basic reactor coolant system layout and equipment. The differences which are significant relative to the TMI accident are discussed below. In addition, the comparison of plant features in Table 3.3-1 covers items in the primary and secondary systems, the steam generators, and auxiliary feedwater systems stating specific parameter values for each plant. Table 3.3-2 specifically compares actions which occur based on pressurizer pressure, with the PBNP and TMI setpoints given.

A. Reactor Vessel Internals: PBNP does not have nor need check valves in the upper internals. If the check valves incorporated in the TMI design are partially open under natural circulation conditions, they could reduce core coolant flow. A portion of the warme[illegible] rising from the core could exit the upper plenum through the [illegible] valves and oppose the colder water attempting to enter the vessel. This could reduce the effectiveness of the natural circulation mode of heat removal.

B. A comparison between the TMI and PBNP RCS layout shows the following major differences:

   1. The layout and elevations of RCS components at TMI, as shown in Figures 3.1-3 and -4, are such that the highest points in each loop in the primary system are in regions of no heat transfer to the secondary side. Voids formed in the core could, therefore, travel to these high elevation regions without passing through regions of heat removal capability and, thus, block natural circulation in each loop. Also, the top of the steam generator tubes may not be covered by secondary side liquid in the TMI design, resulting in poor heat transfer at the steam generator tube entrance region. Evaluation of the Westinghouse inverted U-tube design used at PBNP, as shown in Figures 3.2-3 and -4, shows that the U-tubes remain covered, and the high elevation point in the steam generator is in a region of good heat removal capability. As voids are formed in the core and rise to the steam generator, they are introduced into a region of good heat removal immediately upon entering the steam generator tubes at the bottom of the tube sheet. These voids can, thus, be condensed prior to their reaching the high elevation point in the steam generator.

   2. The elevation of the PBNP inverted U-tube steam generators is such that they are entirely above the reactor vessel nozzles resulting in a short horizontal crossover leg from the steam generator to the pump. This minimizes the mass of cold water in the crossover and cold legs which would oppose the return flow to the vessel during natural circulation. Also, during an accident condition, this design allows the majority of the RCS water mass to drain from the loops back to the core. At TMI, the lowered OTSG results in two vertical crossover legs from the OTSG to each pump. Therefore, a large mass of cold water can accumulate in both the OTSG volume below the vessel nozzles and the crossover leg pipes.

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This produces both a loop seal and a thermal block which can impede initiation of natural circulation and leaves only a small amount of water from the hot leg and upper half of the OTSG to drain back into the vessel during an accident condition.

3. The elevation of the pressurizer relative to the reactor vessel nozzles and the layout of the connecting piping are significantly different between TMI and PBNP. The PBNP pressurizer inlet nozzle is at a higher elevation than the reactor vessel outlet nozzle (hot leg) and the surge line routing is such that there is an upward slope from its connection in the top of the hot leg all the way into the pressurizer. This surge line design for the PBNP units provides a pathway for noncondensable gases to reach the pressurizer vapor space where they can be vented and prevents the creation of a loop seal between the outlet piping and the pressurizer.

4. The PBNP pressurizer is fitted with two power operated relief valves compared to the single valve in the TMI design. Both PBNP valves have stem position indicating lights on the main control board while TMI has indication of only solenoid demand position which may not reflect valve position.

5. The PBNP U-tube steam generator operates with a much larger inventory of secondary-side water at all power levels than does the TMI OTSG. As a result, the initiation of auxiliary feedwater flow after a loss of main feedwater flow is not as crucial to the removal of decay heat as in the TMI design. PBNP has at least 30 minutes until steam generator dryout occurs from normal operating conditions compared to approximately one minute for TMI (the normal trip sequences are assumed for each plant).

C. The PBNP containment sump, which collects leakage within the containment, discharges into a small sump tank at the lowest elevation of the auxiliary building. The line between these two sumps is equipped with two air-operated isolation valves which are normally closed. Both valves receive a containment isolation signal and, as an additional precautionary measure, one of the valves controls requires the operator to physically hold the control switch in the open position in order to open the line between the two sumps. This arrangement is significantly different from the TMI arrangement where the sump is automatically pumped to the auxiliary building based on the level of water in the sump.

A comparison of the physical plant layout features between the PBNP and TMI design has not shown the need for any physical plant design modifications to the PBNP.

TABLE 3.3-1

COMPARISON OF PLANT FEATURES

Item Description	Point Beach	Three Mile Island
REACTOR TYPE	Pressurized Water	Pressurized Water
NSSS SUPPLIER	Westinghouse	Babcock & Wilcox
CORE POWER, MWt	1518	2772
Btu/hr	5181×10^6	9465×10^6
GROSS ELECTRICAL OUTPUT, MWe	524	880
PRIMARY COOLANT SYSTEM		
Number of Hot Legs	2	2
Number of Cold Legs	2	4
Number of Coolant Pumps/hp	2/6,000	4/9,000
RCS Mass Flow Rate, lb/hr	66.7×10^6	137.9×10^6
System Water Volume, ft^3 (at full power)	6040	11148
Pressurizer Volume, ft^3	1000 (600 water/400 steam)	1500 (800 water/700 steam)
Number of Power Operated Valves/	2	1
Flow, lb/hr (each)	179,000	112,000
Number of Self-Actuated Safety	2	2
Valves/Flow, lb/hr (each)	288,000	345,000
Number of Fuel Assemblies	121	177
Active Core Height, inches	144	144
SECONDARY STEAM SYSTEM		
Main Steam/Feed Flow, lb/hr (per steam generator)	3.31×10^6	6.12×10^6
Number of Main Feed Pumps/hp Type/	2/5000	2/8940
Flow, gpm (each)	Motor/7,800	Turbine/15,500
STEAM GENERATORS		
Type	Inverted U-tube	Once-through
Number	2	2
Outlet Steam Condition	Saturated	Superheated (35°F)
Steam Pressure, psig	820	910
Steam Temperature, °F	521	570
Secondary Side Volume, ft^3 (power level)	1681 water/2898 steam (100%) 2821 water/1758 steam (0%)	3412 total Water/steam volumes unknown.
AUXILIARY FEEDWATER SYSTEM		
Number of motor driven pumps/hp	2*/250	2/450
Flow, gpm (each)	200	470
Number of steam driven pumps	1 per unit	1
Flow, gpm	400	940

* Shared between Units 1 and 2 (any 3 of 4 total pumps provide 100% of required feedwater flow for both PBNP units).

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3.4 EVALUATION OF A POSTULATED TMI-TYPE ACCIDENT AT POINT BEACH

This evaluatio follows the same chronology and format as Section 2.4, Autopsy of the Accident. Parallel plant or operator response is examined where the TMI accident is not directly applicable to Point Beach.

A. Initiating Event

Loss of main feedwater flow is a credible accident analyzed in the Point Beach Final Facility Description and Safety Analysis Report. Operator response is to follow the transient and procedures to ensure that all safety and control systems respond properly.

B. Turbine Trip - Reactor Trip Sequence

Operator verification of the trips, but no action is required. Point Beach Nuclear Plant would have incurred a reactor trip at the same time as the turbine trip occurred. This would have resulted in about 8 full power seconds less relative energy being released than at TMI. This becomes a significant amount of energy when compared to decay heat production at 10% or less of full power (8 EFPS = 1.16×10^7 Btu at PBNP compared to 2.12×10^7 Btu at TMI). PBNP has pressurizer relief valve opening and high pressure reactor trip functions similar to TMI (see Section 3.3), but they should not occur on this type transient.

C. Pressurizer Relief Valve Response

A power operated relief valve (PORV) opening on loss of load with a subsequent turbine trip-reactor trip sequence would be abnormal. The operator response is to immediately isolate the valve if it does not close when the pressure drops below the closure setpoint. PBNP is designed such that on a loss of load, the pressurizer power operated relief valve need not open. Heat removal by the secondary side thru the steam dump and steam generator power operated relief valves coupled with the larger (than TMI) relative water mass in the steam generators is sufficient to limit the pressure rise in the reactor coolant system to less than the PORV relief setpoint. Pressurizer spray from two loops will also help to limit the pressure (TMI has spray from only one cold leg in one loop).

D. Auxiliary Feedwater System Response

The operator action is to verify the startup and injection of auxiliary feedwater. Larger steam generator secondary side water inventories do not require as rapid a response as required at TMI to preclude steam generator dryout. Auxiliary feedwater system startup times are comparable to that of TMI being less than $\sim$30 seconds to full pressure and flow.

E. Pressurizer Relief Valve Closure

Closure would be expected upon a sufficient pressure decrease after any opening and would be verified by the operator. Isolation of one PORV, which was not properly reseating, does not result in a total loss of automatic relief capability. There are two pressurizer power operated relief valves on PBNP, each with a larger capacity than the single EMOV on the TMI pressurizer (179,000 lb/hr each versus 112,000 lb/hr). One PORV has a fixed actuation setpoint while the second has an anticipatory rate variable setpoint. The four pressurizer pressure channels provide separate 2/2 logic for the opening of each PORV at its setpoint. A closure signal will, therefore, result if either one of the two channels for a PORV decreases below the closure setpoint. Isolation of both PORVs would still allow pressure control through manual operation of the block valves. The PORVs are designed to open and close and have setpoints below that of the two code safety valves. Thus they would attempt to maintain RCS pressure below the code safety valve setpoint and limit the duty on the safety valves. The code safety valves sole purpose is to protect the RCS against overpressurization at all times. They are therefore designed so that they cannot be isolated.

F. Pressurizer Relief Valve Indication

Operator verification of PORV closure is required. PBNP high pressurizer pressure is alarmed and actual PORV position (open/closed) is indicated on the control board; TMI apparently has only indication of the solenoid position. The combined relief valve line and each safety valve line to the pressurizer relief tank is temperature sensed and alarms on high temperature. The pressurizer relief tank is instrumented for temperature, pressure, and level indication with alarms for high values of each, as well as low level. TMI has level, pressure, and temperature instrumentation on the relief tank. No separate line instrumentation is apparent for TMI.

Indications of Position and Conditions -

1. Actual valve position indications on the main control board.

2. Indication is provided on the main control board of the temperature of the common relief line. This is separate from the individual safety relief lines and their temperature indications.

3. Temperature, level, and pressure indications are provided for the reactor coolant drain tank. Alarms are provided for high temperature and pressure, as well as high and low water level.

4. Redundant pressurizer pressure alarms are provided to indicate high pressure.

G. Steam Generator Inventory Depletion

Operator verification of steam generator steam and feedwater flow, pressure, and level is required to determine the heat removal capabilities. Time to dryout of the steam generators at TMI was about one minute, while PBNP dryout time is on the order of one half hour.

H. High Pressurizer Level Indication

On RCS heatup, the volume expansion would cause an expected pressurizer level increase. The operator would not expect the readings to approach

TABLE 3.3-2

COMPARISON OF PRESSURIZER ACTIONS

Pressurizer Pressure Actions	Point Beach	Three Mile Island
	(Pressure values in psig)	
Hydro Test	3110	3125
Design Pressure	2485	2500
Code Safety Valves Open	2485	2435 (2310 close)
Reactor High Pressure Trip	2385	2355
Power Relief Valves Open and High Pressure Alarm	2335 (2315 close)	2255 (2205 close)
Power Relief Valves Close Interlock	2315	---
Spray Valves Open	2260 (Ramp to full open at 2310)	2155 (Ramp to 40% open at 2205)+
Heaters Off-Variable	2250	2155 (1, 2, 3)++
Operating Pressure	2235	2155
Heaters On-Variable**	2220	2135(1)/2147(2, 3)++
Low Pressure Alarm	2135	2055
Low Pressure Trip	1865	1900
Low-Low Pressure Alarm		1700
Safety Injection	1715*	1640

*Low pressure coincident with low level (<5% of range) was changed to 2 of 3 low pressure only.

**Backup heaters on and alarm at 2210 psig and off at 2218 psig for Point Beach. Backup heaters on at 2020(4)/2015(5) psig and off at 2140(4)/2125(5) for TMI.++

+Full valve range available in manual control mode.

++TMI has 13 pressurizer heater groups in 5 banks (Bank numbers are noted in parenthesis).

or exceed the upper level readings. PBNP has sealed reference legs on the pressurizer level instrumentation; TMI apparently has open reference legs which may have introduced some error into the TMI readings. PBNP capabilities of 40% of load steam dump, 10% of load power operated relief valves on the steam lines, and the reactor trip on turbine trip should limit the high pressurizer level indication by both removing the system stored energy and limiting primary system temperature rise (by limiting core heat production).

I. Termination of High Pressure Safety Injection

Once safety injection has been initiated either manually by the operator or automatically by the two-out-of-three low pressurizer pressure logic, injection will continue even if the initiating conditions disappear. An operator can manually terminate safety injection but a built-in delay limits how rapidly this can be done. Initial water injection is from a boric acid tank with 20,000 parts per million concentration of boron. TMI uses water for safety injection of about 2,000 parts per million of boron.

J. RCS Pressure Drop and Void Formation

As noted in I above, the current low pressurizer pressure logic would automatically initiate a safety injection for a significant drop in RCS pressure. This would occur even if the normal pressurizer level was maintained or was increasing due to an RCS heatup. Either a continued decrease in pressure or increase in temperature could result in void formation somewhere in the RCS; most probably in the vessel. The PBNP pressurizer and surge line layout (see Item P below) would not prevent the pressurizer from draining back to the vessel via the hot leg. This would provide additional water in the vessel to displace the void and keep the core covered until the pressurizer is emptied. The pressurizer water level would therefore reflect the RCS water inventory. A low enough pressure would allow both the accumulators to discharge into the vessel and residual heat removal flow to be established.

K. Reactor Coolant Drain (Pressurizer Relief) Tank Indication

The PBNP pressurizer relief tank for the pressurizer power operated relief valves and safety valves is a static volume, dedicated tank designed to receive primarily the pressurizer discharges and any discharges from normally closed pressure relief valves from various systems. There is a separate reactor coolant drain tank (RCDT) with its associated pumps and heat exchangers for all other primary coolant leakoffs and drains. TMI has a combined tank for all primary reliefs and discharges which means that it normally sees changes in level, temperature, and pressure. The PBNP pressurizer relief tank (PRT) has a spray as well as drain to the RCDT system which provides for two methods of controlling PRT pressure, in addition to the normal condensing of relieved steam achieved by underwater discharge in the tank. TMI has two trains of heat removal from the combined tank. Each train consists of a transfer pump and heat exchanger. Both plants use N_2 as a cover gas. PBNP vents to the waste gas processing system, while TMI is interconnected to the reactor coolant bleed tanks with isolation at 10 psig.

L. Pressurizer Relief Valve Isolation

Isolation of a PORV which has not reclosed or properly reseated, is an operator action. The second PORV at PBNP still would provide relief capability so the operator should not hesitate to isolate one. Overpressure protection is always provided by the two code safety valves (see E above).

M. Rupture Disk Relief

As at TMI, no automatic actions stop any RCDT relief. Operator isolation of the PORV line is required if this is the source of the flow. The safety valves cannot be isolated.

N. Startup of Containment Sump Pumping

Sumps at PBNP cannot be automatically pumped down as in the TMI accident. Operator action is necessary to open and hold open any discharge valves. This would confine any releases to the containment building volume. TMI had RCS releases via their drain tank relief valve and rupture disk. PBNP has no relief valve, but does have a rupture disk.

O. Containment Isolation Signal

Automatic safety injection would automatically isolate the PBNP containment except for necessary safeguards penetrations preventing many of the releases that TMI encountered early in the accident. High activity would isolate the purge system and high-high containment pressure (25 psig) would initiate containment spray. Both plants also have manual isolation.

P. Surge Line Layout

The PBNP surge line is a 10-inch pipe gradually increasing in elevation from its penetration at the top of the hot leg piping to the bottom inlet to the pressurizer. TMI has a surge line which comes off the side of a vertical hot leg pipe, turns 90° down parallel to the vertical portion of the hot leg, turns 90° horizontal to run under the hot leg, then turns 90° horizontally away from the reactor vessel to under the pressurizer, and then turns 90° up into the pressurizer. Thus a loop seal is formed in the TMI surge line. This configuration is not found at PBNP and allows for easy coolant flow into and out of the PBNP pressurizer.

Q. Reactor Coolant Pump Stoppage - Loop Isolation

Operators would probably isolate a steam generator on the secondary side with a known leak where radiation levels are increasing.

Shutdown of both pumps and loops is unlikely; but with two phase flow in the RCS, a loss of NPSH or pump vibration would eventually require shutdown so that the pump can be saved and used later. The operator should retain the capability to start and stop reactor coolant pumps based on RCS conditions.

R. Establishing Natural Circulation

Operator verification of the establishment of natural circulation is required using the wide range temperature indication. Thermocouple computer printout can also be used. Natural circulation tests have been run successfully at low power levels at PBNP (comparable levels to that of decay heat energy production).

S. Primary Loop Layout - Hot Leg

The hot leg piping is not elevated at PBNP in contrast with TMI and the highest point in a primary coolant loop is inside the SG. Thus, condensate can be returned to the RCS via the hot leg directly and all of the elevated portions of the hot leg can be cooled. The hot leg piping runs horizontally from the vessel outlet nozzle level to the steam generator inlet nozzle.

T. Primary Loop Layout - Cold Leg

A very small volume of the PBNP RCS is in the cold leg and crossover piping. Minimal elevation heads exist in the return line from the steam generator, thus promoting natural circulation. Most of the cold leg is horizontal at the nozzle level or slightly above the inlet nozzle elevation. The crossover leg, from the steam generator to the pump, is below the components but above the core.

U. Repressurization and Pressure Response

Isolation of an open PORV at PBNP and the resulting pressure response would be similar to that of TMI with possibly better instrumentation response due to the sealed reference legs. (See Item H. above)

V. Pressure Control with Relief Isolation Valve

This is not a normal mode of control since the operator can control pressure using the pressurizer heater and spray controls (two spray lines from the RCS loops are available). If PORVs are used, a similar uncovering of the core to that which occurred at TMI could occur at PBNP. Relief capacity is larger from the PBNP pressurizer via the two larger (than TMI's single) PORVs; thus, faster depressurization to a lower value is possible at PBNP.

W. Attempt to Institute RHR System

Normal cooldown at PBNP is accomplished using the steam generators until RHR initiation pressure and temperature are achieved. TMI attempted to depressurize using the pressurizer relief capability. The PORV relief capability at PBNP is larger and with one or both PORVs open, the RCS would depressurize rapidly. Most probably this would result in pressures low enough to institute RHR, but voiding could occur and temperatures would be elevated. This would result in SI actuation and subsequent accumulator discharge at low pressure unless a slow, controlled cooldown is affected.

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3.5 SMALL BREAK AND OTHER TRANSIENT CONSIDERATIONS IN A WESTINGHOUSE PWR

A description of system behavior for the range of postulated small break LOCAs is provided, beginning at the small end of the break area spectrum. The effect of initiation of auxiliary feedwater is also discussed for all break sizes. Unless otherwise noted, all cases described use Appendix K assumptions (minimum safeguards, loss of offsite power).

A. Breaks ≤3/8" Diameter Hole

Breaks in this range of size are considered to be leaks, rather than small LOCAs. The distinction of a leak from a small LOCA means that the normal charging flow from the chemical and volume control system is capable of maintaining pressurizer pressure and level. No system depressurization occurs and there would not be an automatic trip or safety injection signal generated. The operator will become aware of the leak due to a low level in the volume control tank, containment radiation, excessive charging flow, etc. He then may initiate a normal shutdown. Core heat is removed by either forced or natural circulation through the steam generators, so that auxiliary feedwater is required to maintain the heat sink. No core uncovery or voiding will occur.

The system response is similar regardless of the location of the leak.

If, for this case, auxiliary feedwater was not available, secondary water inventory would be capable of supplying the necessary heat sink for a period of approximately 30 to 45 minutes.

B. Breaks 3/8" < Diameter <∿1"

For these break sizes, the normal makeup system cannot maintain RCS pressure and level. The RCS will depressurize and a reactor trip and safety injection signal will be generated. The system will reach an equilibrium pressure which corresponds to the pressure at which the liquid phase break flow equals the high head pumped safety injection. For PBNP, it has been verified that this equilibrium pressure condition will be established for plants with and without safety grade charging pumps. This equilibrium pressure will be established above the steam generator safety valve setpoints for these break sizes. Core heat can be removed by natural circulation for these cases. The fluid in the system is saturated or subcooled liquid except in the core and hot legs, where small values of void fraction exist. The steam generator tubes do not drain and the natural circulation heat removal mode continues until the time that the break can remove all the decay heat (∿1 day for a 1" break). Prior to this time, auxiliary feedwater is required to maintain the heat sink. Since the break flow is significantly less than the loop flow induced by natural circulation, the response of the system is similar regardless of the break location.

The discussion concerning the system response assuming no auxiliary feedwater flow available presented for leaks <3/8" diameter also applies for breaks of this size.

C. Breaks ~1" < Diameter <~2"

For these break sizes, the RCS will depressurize with a reactor trip and safety injection signal generated. During the early stages of the depressurization, the safety injection flow cannot keep up with the break flow and the water inventory in the system decreases. The RCS pressure falls below cold leg saturation condition and voids form throughout the system. Eventually the steam generator tubes begin to drain and the mixture level on the primary side may drop completely below the steam generator tubes. At this time, the break is still not capable of removing decay heat, so the steam generator is relief upon for some period of time. The mode of heat transfer at this time is condensation. Eventually, the break can remove all the decay heat allowing further depressurization. There may be a slight core uncovery during this transient, but peak clad temperatures are on the order of 1000°F for these break sizes. The system becomes stable at some pressure, dependent on the break size, below the steam generator safety valve setpoints. This stability can be described as a fully covered core, the break removing all decay energy, and the pumped safety injection flow being greater than core boiloff.

Since the steam generator is relied on as a heat sink, auxiliary feedwater is required, and the consequences discussed previously exist, should auxiliary feedwater not be available. However, as the greak size increases, the critical time period between the time of steam generator secondary dryout and the time when the break can remove all decay heat decreases.

The heat removal modes that exist for this range of breaks would exist in a similar fashion regardless of break location. Cold leg break locations are the worst case in terms of peak clad temperature, due to the fact that the break is more isolated from the core because of the relatively small loop seal in the crossover pipe (approximately 8.5 ft for PBNP vs. 33 ft. for TMI).

D. Breaks >~2" Diameter Hole

For these break sizes, a rapid depressurization occurs with corresponding reactor trip and safety injection signals being generated. This is representative of a PORV at PBNP (nominal 2 inch valve on a 3 inch line).

The RCS tends to form voids much more rapidly than the smaller break. The break is capable of removing all decay heat relatively early in the transient. There is less reliance on the steam generators to remove core decay heat. The system again becomes stable at a low RCS pressure, dependent on break size. At this point, the break is removing all decay heat and the pumped safety injection is greater than the boiloff rate in the core.

The sensitivity to auxiliary feedwater flow availability for these breaks is negligible, since the steam generator is required to remove heat for only a short time very early in the transient. For this limited time, there is enough secondary water inventory to provide an adequate heat sink.

The size range of breaks postulated to occur in the cold leg are the worst small breaks in terms of peak clad temperature. Breaks in the hot leg and crossover leg have been analyzed and result in less core uncovery and lower peak clad temperatures than cold leg breaks.

Cold leg breaks are always worse because of the necessity of clearing the loop seal of water in order to vent steam generated in the core out the break. Also, these cases represent the greatest break flow path resistance and, thus, more steam binding. For hot leg, pressurizer, and crossover leg breaks, venting of steam can occur without completely clearing the loop seal of water.

For these break size transients, the major core uncovery occurs after the loop seal blows and the break flow is saturated steam. During this uncovery period, the core boiloff is greater than pumped safety injection. Thus, core mixture level elevation decreases and the clad temperature increases. RCS pressure decreases until the cold leg accumulators inject and turn around the clad temperature by recovering the core. As depressurization continues, the pumped safety injection matches core boiloff, and the core remains fully covered.

For many of these break sizes, the primary system pressure and saturation temperature fall well below the secondary side pressure and saturation temperature, and the steam generator becomes a heat source rather than a heat sink. This phenomenon is modelled in the PBNP small break analyses.

E. Limiting Feedwater Transients

A description of system behavior for feedwater related limiting transients combined with a stuck open power operated relief valve, considering cases with and without auxiliary feedwater, have been analyzed and the results of these analyses are presented. The accident scenario and analysis assumptions were as follows:

- 4 loop standard Westinghouse type plant, 3411 MWe (this will bound PBNP in terms of heat generated)

- Loss of feedflow accident at t = 0 sec.

- Trip on lo-level coincident with steam/feed mismatch

- Assume no auxiliary feedflow through first 2000 sec. in the transient. (Thru this time, t = 2000 sec., liquid is still present in the steam generator secondary, and there has been no core uncovery. This is representative of PBNP dryout time also.)

- Due to the no auxiliary feedflow assumption, the PORV was calculated to open at t = ~2000 sec.

The above assumptions basically describe the loss of feedflow accident. At the time of opening of the PORV, the valve is assumed to stick fully open, and the small LOCA analysis begins. The assumptions for this phase of the analysis are:

- One PORV fails to close at t = 2000 sec. The area of the PORV equals 0.025 ft^2.

- Assume no liquid mass in any steam generator.

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- Loss of offsite power conditions:

  a. No steam dump from the steam generators via the power operated relief valves or the steam dump systems; venting through steam generator safety valves only.

  b. RC pumps tripped

  c. Minimum safeguards safety injection available

  Case 1 - No auxiliary feedwater available at any time

  Case 2 - Minimum auxiliary feedwater (one pump) begins at ~2000 sec.

  Description of System Behavior for Case 1

  For this case, the steam generator provides essentially no heat removal capability. The reactor coolant system rapidly depressurizes early in the transient when the primary side is subcooled. From 2200 sec to 3200 sec, the primary side repressurizes. The break flow during this time period is saturated liquid and cannot remove all of the core heat. At 3200 seconds, the break flow becomes predominantly saturated steam, and can remove all decay heat. From this point on, the system depressurizes. At high system pressures that exist to 4500 sec, there is a loss of primary liquid mass through flashing and boiling in the core that is not completely made up by pumped safety injection. This situation results in slight core uncovery. Eventually, the safety injection flow matches the loss of liquid mass and the core recovers at 6000 seconds in the transient. At this point, the break is removing all decay heat, and pumped safety injection is greater than boiloff. The core will not experience any further uncovery. The peak clad temperature for this case is 1372°F.

  Description of System Behavior for Case 2

  For this case, minimum auxiliary feedwater is assumed to initiate at ~2000 seconds. Note that if auxiliary feedwater was initiated early in the transient, the PORV would not have opened due to the loss of feedflow accident. The system depressurizes quickly to saturation conditions as in Case 1, but no repressurization occurs because the break plus the steam generator, mainly by means of condensation heat transfer, can remove all decay heat. At approximately 3000 sec in the transient, the primary system pressure drops below the steam generator safety valve setpoint, and the break is removing all decay heat. From this time in the transient, auxiliary feedwater and break energy removal provide for continued depressurization. At 6000 sec in the transient, the system is stable in that the break is removing all decay heat, and the pump safety injection is matching core boiloff. There is no core uncovery for this case, therefore, the clad temperature never exceeds the initial steady state operating clad temperature.

In Case 1 above (no auxiliary feedwater), the lower shutoff head of the PBNP high pressure safety injection pumps would have a significant effect on the transient. In Case 1, the uncovery of the core will be greater and last longer than for the 4-loop standard plant analyzed. This will result in higher peak clad temperature values. This is due to the fact that less water is injected during the initial depressurization and repressurization period and the equilibrium of matched injection and break flow is reached later at a lower pressure. The time scale of events for Case 2 above would change for PBNP, but the results should be essentially the same.

From Figures 3.5-1 and 3.5-2, it can be seen that injection for Case 1 would not begin until ~2100 sec and since pressure remains high, the injection rate would remain low. The repressurization of the system will then shut off the SI flow. Also, since the PORV cannot release energy at the decay heat production rate, the temperatures increase. Continued mass and energy release through the PORV result in significantly greater core uncovery than Figure 3.5-3, until the pressure drops and SI begins again. SI would not be injecting from ~2600 to ~4500 sec. Then equilibrium would also occur later in time (SI equalling decay heat). Differences in the relative sizes of the PORVs must also be considered. PBNP has a PORV capacity of 179,000 lb_m/hr, while the 4-loop standard plant has a PORV capacity of 210,000 lb_m/hr. When compared to other plant parameters important to the transient, it is estimated that PBNP will have approximately twice the relative rate of energy and mass release. This should mitigate some of the consequences of the lower shutoff head of the HPSI pumps. The greater relative relieving capacity should cause the depressurization to occur more quickly and drop to a lower level. This will allow SI to begin sooner. More SI water will thus be injected and at a higher rate. Equilibrium levels may be lower to match the greater relief capacity but will be achieved earlier.

It can be concluded that the small break behavior is applicable to PBNP directly. The second case of the PORV failure, which considers delayed auxiliary feedwater, would be similar for PBNP except for time scale. In these, there will be none to slight core uncovery with slight increases in peak clad temperature. For the first case of PORV failure with no auxiliary feedwater, the consequences could be core uncovery and increases in peak clad temperature.

F. Pressurizer Level Response

For the PORV release or a small break in the area of the pressurizer steam space, a significant concern is the response of the pressurizer level instrumentation. As the break relieves the steam space volume, the pressure drops and several things occur. As the pressure decreases in the pressurizer due to loss of mass from the steam space, some of the water in the pressurizer will flash to steam when the saturation temperature drops below the water temperature. This will tend to retard the decrease in pressure. The subsequent level response would be a decrease proportional to the amount of liquid flashing to steam if this effect is considered alone. The decrease is slowed somewhat by the reactor coolant system expansion due to the decreasing pressure. This expansion results in some inflow of water to the pressurizer. Typically this inflow is at a temperature below that of the fluid already in the pressurizer and can result in a bulk drop in temperature. Unless the pressurizer heaters are turned on to add heat and compensate for this reduced temperature, an additional component is added to the level which can cause a decrease. The heater control system is designed to do this with heater actuation for decreasing pressure and also for a level deviation high (large inflow). If pressure drops enough so that the corresponding saturation temperature is below the core exit temperature, voids form in the vessel and the pressurizer level response now becomes dependent upon system configuration as well as the fluid properties.

Any flashing of core exit flow to steam will result in a positive displacement of water into the pressurizer. This will continue as long as the coolant is under the conditions of forced convection (reactor coolant pumps running) and the steam is swept along with the bulk flow. If the vessel exit temperature is maintained below saturation due to ambient heat losses or bypass flow mixing, the steam bubbles will collapse in the subcooled water and no steam transport to the steam generators or pressurizer will take place. Once the pressure and its saturation temperature drops to the point where steam is swept into the hot leg, it is either carried to the steam generator and condensed or carried through the surge line into the pressurizer. The latter will allow the steam from the vessel to migrate to the vapor space, displace water back into the reset of the RCS and, thus, cause level to drop which will reflect actual system mass inventory loss. However, if the surge line forms a loop seal between the pressurizer and the rest of the RCS, this path is lost. Then the pressurizer level will indicate high when, in fact, there are voids and the inventory is decreasing. This situation occurred at TMI. It was further aggravated by the RCS heatup and expansion into the pressurizer. This took place early in the TMI transient as the secondary side of the OTSGs dried out and removed the primary heat sink. The result was a full pressurizer and offscale high level indication. The indication of a full pressurizer remained even after the hot leg was completely voided because there was no driving heat to force the water out of the pressurizer. A loop seal in the surge line therefore prevents voids from flowing into the pressurizer to displace the water in it and allow it to drain.

The Point Beach Nuclear Plant surge line does not form a loop seal and, thus, allows for the transport of steam voids to the pressurizer under all conditions. The pressurizer level will, thus, more accurately reflect the RCS mass inventory even if an initial system swell due to heatup were to fill the pressurizer.

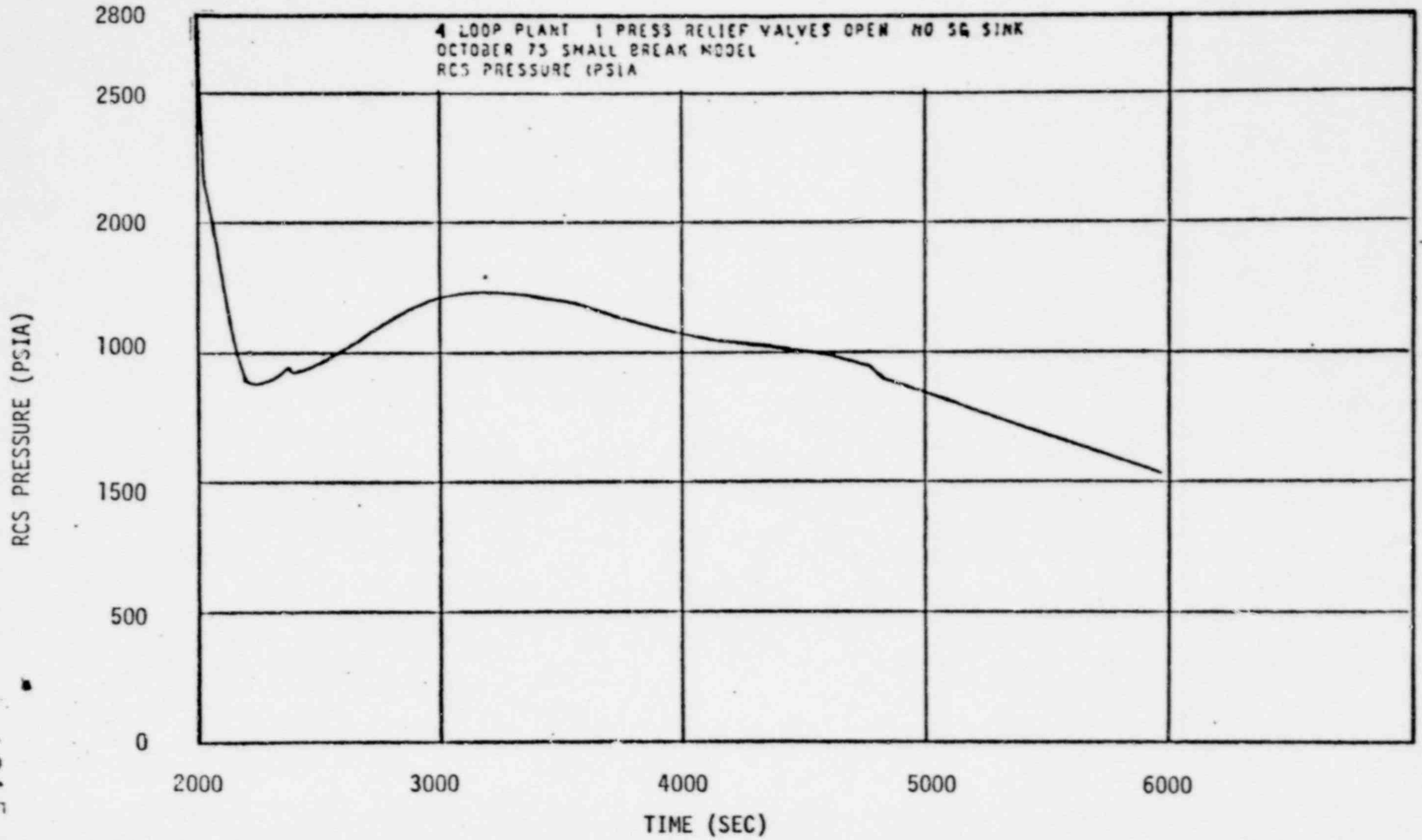

FIGURE 3.5-1 RCS PRESSURE VERSUS TIME FOR A RELIEF VALVE OPEN AND NO STEAM GENERATOR HEAT SINK - OCTOBER 1975 SMALL BREAK MODEL

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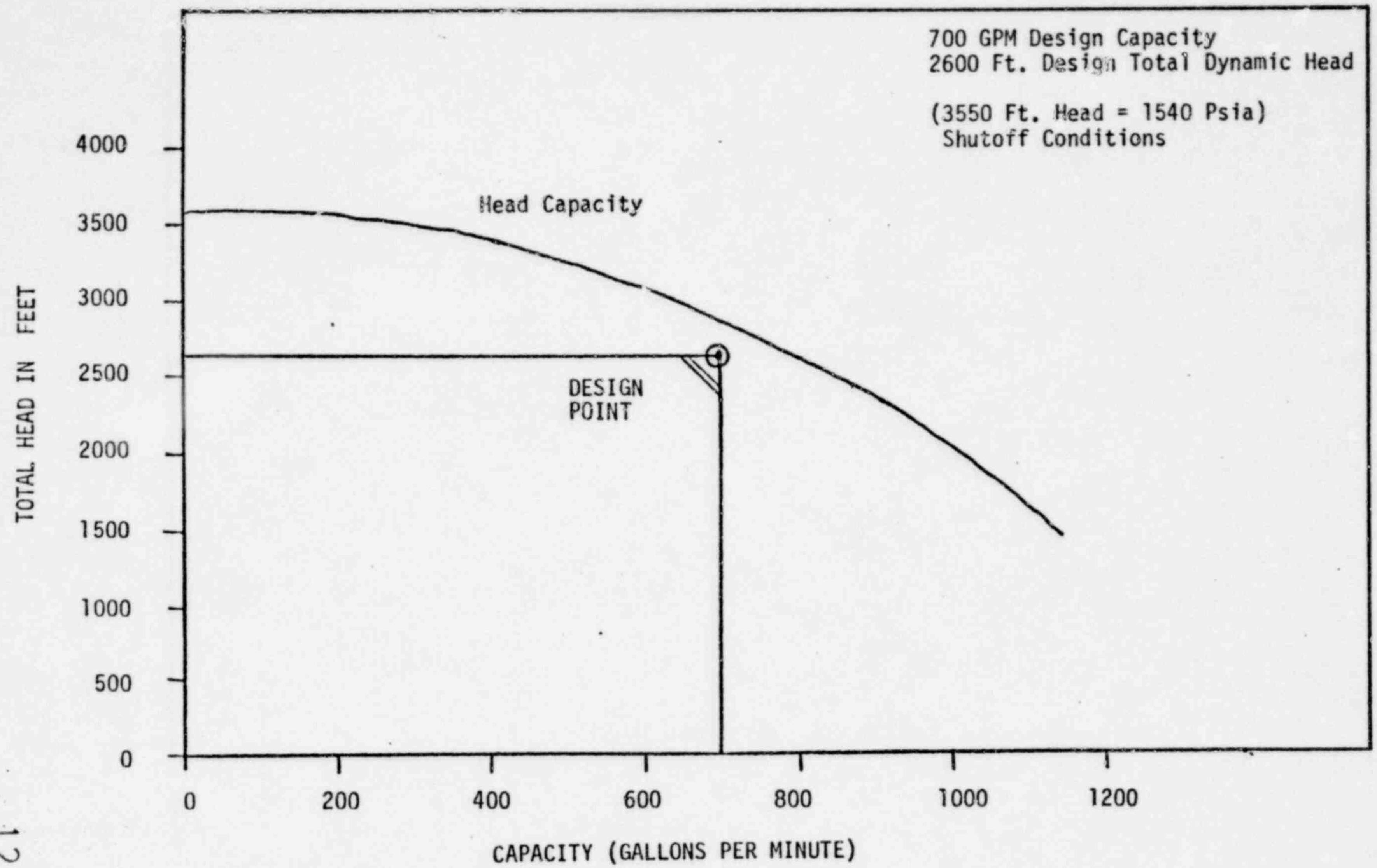

FIGURE 3.5-2 TYPICAL HEAD VERSUS CAPACITY CURVE FOR WEP - WIS SAFETY INJECTION PUMPS

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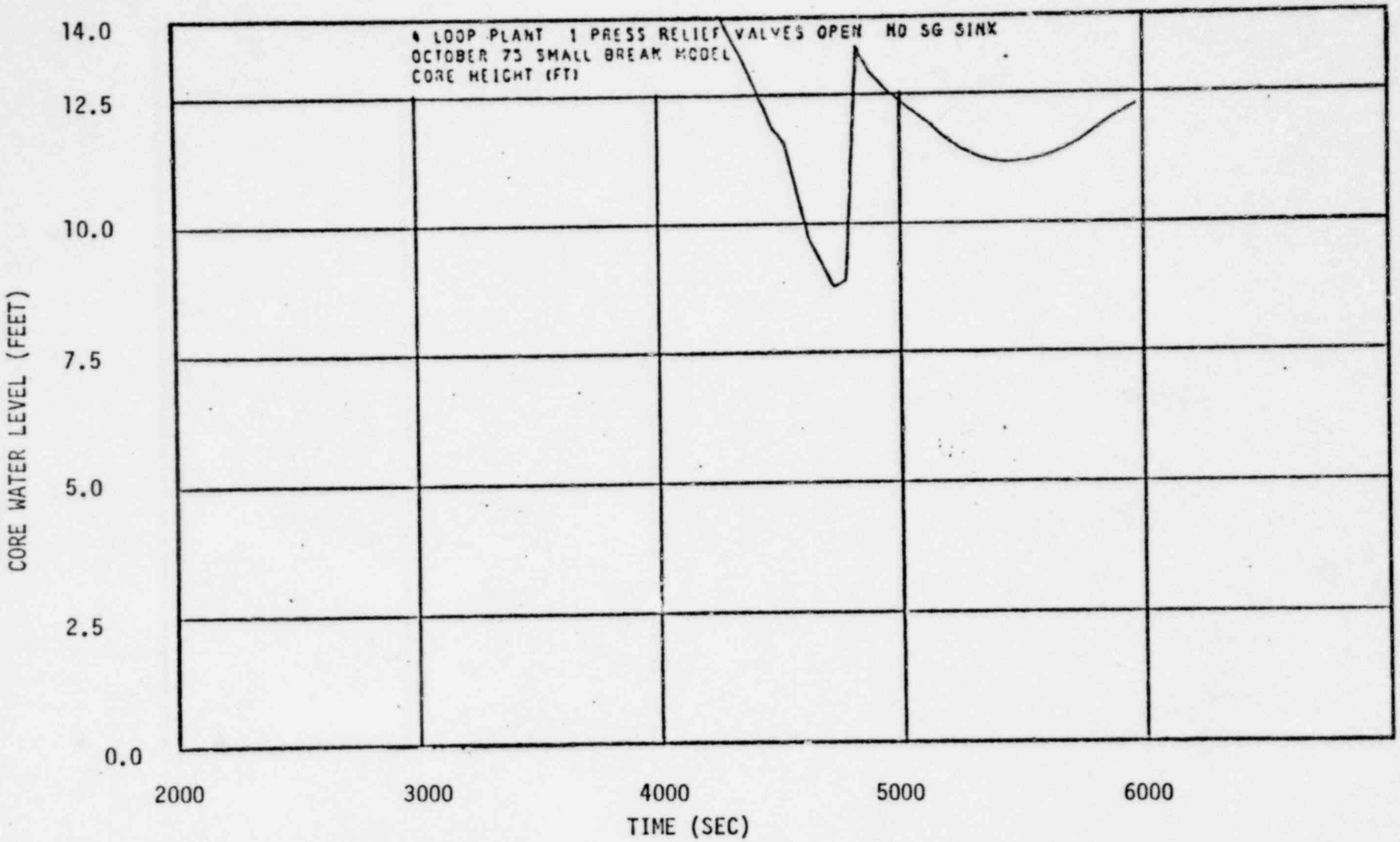

FIGURE 3.5-3 CORE WATER LEVEL VERSUS TIME FOR A RELIEF VALVE OPEN AND NO STEAM GENERATOR HEAT SINK - OCTOBER 1975 SMALL BREAK MODEL

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3.6 SUMMARY OF RELATED EVENTS AT POINT BEACH NUCLEAR PLANT

The incident summaries in A thru J below are a chronological listing of selected events which have occurred at the Point Beach Nuclear Plant, Units 1 and 2, that are similar to portions of the accident which occurred at Three Mile Island in one or more ways. The majority of these items discuss events which resulted in a partial degradation of the auxiliary feedwater system (D, E, F, H, and J) as shown in Figure 3.2-12. As discussed, eitner redundant means existed to provide the units with auxiliary feedwater or steps were taken to comply with the Technical Specification requirements of Limiting Conditions for Operation. In no case was the health and safety of the public affected by the events at the Point Beach Nuclear Plant.

Two of these events (G and I) represent small reactor coolant leaks of the magnitude discussed in Section 3.4.A. In both cases, normal reactor coolant system conditions were maintained using normal charging flow, and Engineered Safeguard Features were not required to function. The unit was shut down and cooled down in a controlled and systematic manner in both instances.

Related events which are also summarized include a reactor coolant system pressure transient due to inadvertent opening of a power operated relief valve (A), a loss of feed flow reactor trip (B), and a containment drain valve mis-operation (C). In all cases, with the exception of the initiating event, plant and systems performance were as expected with no significant deviations. Corrective actions were taken. When necessary, the lessons learned were reflected in plant modifications to preclude recurrence of the event and included in operator training programs.

A. Pressure Transient from Inadvertent Opening of a Power Operated Relief Valve (AO-12-70)

On October 31, 1970, (before initial criticality of Unit 1 on November 2) during functional test H.8.5, Setpoint Verification, a pressure signal was simulated in the pressure control circuitry. The channel had not been placed in the defeat mode. The test signal opened a PORV and caused primary pressure decrease from 2235 to 1915 psig. The transient was terminated by alert operator action in shutting the PORV blocking valve. When the test signal was removed, the PORV shut and the blocking valve was reopened. No radioactive releases occurred as a result of this event and the health and safety of the public was not affected.

B. Loss of Feed Flow Reactor Trip (AO-22-70)

On December 17, 1970, while operating at 35% power, Unit 1 reactor tripped due to a loss of the "B" main feedwater pump. The "A" main feedwater pump was tagged as being out of service. The reactor tripped on a steamflow-feedflow mismatch. Auxiliary feedwater pumps restored the steam generator levels to normal. Initial evaluation of the event was hindered by the red tag on the "A" main feedwater pump covering the indicating lights on the "B" main feedwater pump. A shorted pressure switch which initiated the "B" main feedwater pump trip was replaced and the unit returned to service.

C. Sump "A" Drain Valve Misoperation (SOE 28-71)

On May 28, 1971, While operating at full power, a Unit 1 sump "A" high water level alarm was activated at 1210. The operator opened the sump valve to drain the sump. At 1630, the operator for the next shift noticed the sump valve was still open. The sump drain valve control switch was subsequently modified to a spring return-to-shut switch. No radioactive releases were made during this event and the public health and safety was unaffected.

D. Auxiliary Feed Pump Suction Strainers (AO 74-14)

On April 7, 1974, during a cooldown of Unit 1 for refueling outage, operators notices that the electric auxiliary feedwater pump was not delivering feedwater at an adequate flow rate. Investigation revealed nearly plugged pump suction strainers in the motor-driven auxiliary feedwater lines. The strainers were of the type commonly used for post-construction (startup) clean up. Similar strainers were found in the suction to both steam driven auxiliary feedwater pumps; however, these strainers were not clogged. All of the strainers were removed. The safety analysis for loss of normal feedwater supply presumes only one motor-driven auxiliary pump at 200 gpm is available. In this event, the 400 gpm steam-driven auxiliary feedwater pumps were fully available. The public health and safety was not affected by this event.

E. Failure of Steam Generator Auxiliary Feed Valve to Open Electrically (AO 74-54)

The auxiliary feedwater discharge valve from the unit's turbine-driven auxiliary feedwater pump to the Unit 2 "A" steam generator failed to open electrically. This event occurred on December 21, 1974, during the initial post-refueling startup of the unit. The problem was traced to an incorrect setting of the torque switch. The torque switch was adjusted to its proper setting and the valve was tested satisfactorily.

F. P38A Auxiliary Feed Pump Failure Due to Improper Valve Lineup (SOE 75-3)

On March 7, 1975, the impeller wearing rings and one impeller were damaged after an operator started and operated the P38A feedwater pump with the "A" condenstae storage tank outlet valve closed. The operator had failed to check the valve lineup in accordance with procedure. The pump was tagged out and repaired. Redundant auxiliary feedwater components remained operational during the incident and no Limiting Conditions for Operation were exceeded.

G. Steam Generator Tube Failure (LER 75-4, Unit 1)

On February 26, 1975, at 11:12 p.m., while operating at full power, Unit 1 experienced a steam generator tube failure in the "B" steam generator. The failure resulted in a primary to secondary leak rate of 125 gpm. The charging pumps were able to keep up with this leak rate. The reactor was unloaded to 25% of full power at the rate of 5%/minute and then manually tripped. The "B" main steam stop was shut and the reactor cooled down and depressurized using the "A" steam generator condenser steam dump. The reactor coolant system was at cold shutdown condition approximately seven hours after recognition of the accident. The NRC resident inspector was informed of the incident at 0600 on February 27, 1975. A news conference was held reporting on the incident twelve hours after the start of the incident. The steam generators were eddy current inspected and the leaking tubes plugged. The unit was returned to service on April 5, 1975. All radioactive releases which resulted from this incident were reported to the Commission in licensee's letters dated March 8 and 11, June 26 and August 8, 1975, and were a small fraction of the maximum permissible limits allowed by Part 20, Title 10, Code of Federal Regulations, and thus had no offsite safety significance.

H Failure of Valve MOV-4020 to Close (LER 76-1, Unit 1)

While attempting to remotely operate valve MOV-4020 during a required periodic test, it jammed in the full open position; however, it continued to be operable manually. This is the discharge valve for the motor-driven auxiliary feedwater pump P38B to the Unit 2, B steam generator. Since the Unit 1 steam driven auxiliary feedwater pump had been tagged out for maintenance, it was recognized that the minimum number of pumps required for two unit operation were not available. The Unit 1 reactor, which was at that time critical at zero power, was immediately taken subcritical. An investigation of valve MOV-4020 disclosed a worn operator ring gear. The gear was replaced and the valve was retested successfully.

I. Failure of Pressurizer Spray Valve Swagelok Fitting (LER 77-05, Unit 1)

On June 20, 1977, while operating at 100% power, indication of an 8.14 gpm reactor coolant system leak was noted for Unit 1 and shutdown was commenced at 1313. The reactor was at hot shutdown by 1440. Cold shutdown was achieved at 2255. Investigation revealed a failed swagelok fitting on the pressurizer spray valve bellows pressure gauge. Approximately 7,000 gallons of primary coolant was released to the containment during the incident. Following repairs and containment clean up, the unit was returned to service two days later. No unmonitored or unscheduled liquid or gaseous radioactive releases occurred as a result of this event.

J. Auxiliary Feedwater Isolation Valve Failure to Open (SOE 78-03)

During inservice testing, auxiliary feedwater isolation valve MOV-4022 to the Unit 2 "A" steam generator failed to open due to an open thermal overload. This is the discharge valve for the motor-driven auxiliary feedwater pump P38A to the Unit 2, A steam generator. It was determined that the torque switch was out of adjustment causing excessive closing torque after the valve was shut and resulting in tripping of the thermal overload. The torque switch was adjusted and the valve tested and returned to service. Redundant auxiliary feedwater components remained operational during the event so that no limiting conditions for operation were violated.

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The review of these events did not identify any deficiences in design or procedures. All equipment failures or malfunctions were promptly corrected and the plant returned to service without affecting the health and safety of the public. Operator training programs were modified where necessary to include these events. The reports of these events were provided to and discussed with the operators and other plant personnel shortly after their occurrence, as provided for by plant administrative procedures.

SECTION 4

REVIEW OF PLANT PROCEDURES AND OPERATIONS

4.1 INTRODUCTION

The procedural and operational review conducted by the Task Force focused on the key events that contributed to the TMI accident. The sequence of events described in Section 2 (as developed from information provided by the NRC, B&W, Metropolitan Edison, and other industry sources) provided the guidance to conduct the review. Point Beach Nuclear Plant procedures and operating practices were evaluated for adequacy in preventing the conditions which led to the TMI accident, as well as for their adequacy in facilitating recovery from any similar conditions. Both specific procedures and general operating practices were evaluated.

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4.2 AREAS OF PROCEDURE AND OPERATIONAL REVIEW

4.2.1 Auxiliary Feedwater Isolation

PBNP procedures regarding Auxiliary Feedwater System Operation have been reviewed. This review covered:

A. Initial valve line up and precritical check lists

B. Startup and shutdown procedures

C. Normal operating procedures

D. Emergency operating procedures

E. Periodic testing procedures

F. Periodic valve position and lock check procedure

G. Shift log valve position checks

H. Equipment removal from service and/or isolation procedure

I. Routine and special maintenance procedures

This review has determined that the steam generator dryout event that occurred at TMI would not occur at PBNP as a result of errors or omissions in the existing plant procedures.

PBNP procedures guard against and provide assurances that isolation of both trains of an Engineered Safety Feature (ESF) system (auxiliary feedwater) will not occur. This is accomplished by providing redundant administrative controls and some alarm features. Specifically, the following administrative controls are used on all ESF systems:

A. All routine operational test procedures and system initial and monthly valve position verification and lock check lists have individual steps that require one or more of the following: the recording of valve position, the recording of lock ID number, operator initials indicating correct position was observed.

B. As part of the shift routine, all ESF control equipment, motor and air-operated valves, and instrument and power breakers are checked for correct position. Some of these checks are recorded in the control room logs requiring operator initials and operations supervision review. These required operator log checks are being expanded to include all ESF items on the control boards. The auxiliary feedwater valves are part of this expanded scope.

C. The control room is provided with an ESF equipment status board. Removal of ESF equipment from service or placing ESF equipment in a degraded mode is a required station and control operator log entry item. Also, the plant equipment isolation procedure is required for the removal from service, or isolation of, any ESF system or component. This procedure requires the operations personnel to review and record applicable sections of the Technical

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Specifications on the procedure and also indicate applicable tests required prior to, and following removal of, the system from service.

D. Operating procedures require that a precritical check list be completed prior to taking the reactor critical. This check list systematically requires the operators to verify that all ESF systems are operable, which includes the auxiliary feedwater system.

The auxiliary feedwater system is used frequently during startup and hot shutdown operations. This plant operational feature provides the operators training and system operation familiarity not available on the other ESF systems. The TMI auxiliary feedwater system condition with both trains isolated could occur at PBNP if, for example, the steam driven auxiliary feedwater (AFW) pump was out of service on the operating unit and the other unit was shut down in hot standby with steam generator level being controlled with the electric AFW pumps. In this condition, the motor-driven AFW pump's discharge isolation motor operated valves to the operating unit would be administratively shut. This set of conditions and mode of operation is allowed by PBNP current Technical Specifications and is considered a routine operation. PBNP Emergency Operating Procedures (EOPs) specifically require the operator to close the unaffected unit's electric AFW pump discharge isolation valves when the transient starts AFW in the affected unit. This condition is a result of the shared electric AFW pump arrangement at PBNP.

The designer has determined through computer codes, and it has been verified by Wisconsin Electric, that at least 30 minutes of secondary coolant inventory is available at normal operating conditions in the recirculation-type steam generators used in the PBNP design. In the event an accident occurs on the operating unit, this design feature provides adequate time for operators to reopen any electric auxiliary feed pump discharge isolation valves that were shut.

Auxiliary feedwater system, unlike other ESF systems, does not have individual train flow indication or a Ready Status indicator panel display on the safety features control board. Ready Status indicator panels provide operators a quick check of system operability and the flow meters provide a positive check that flow has been established once the system has been activated. Currently, PBNP operators rely on observing a constant steam generator level or a change in level to determine whether water is being delivered to the steam generator. Auxiliary feed pump discharge pressure is also used as an indication of flow.

4.2.2 Stuck Open Power Operated Relief Valve

PBNP procedures, regarding Loss of Coolant Accidents (LOCAs), have been reviewed. This review specifically covered the stuck open power operated relief valve accident and generally reviewed small LOCAs. The review has shown that EOP-1A and 4A would be utilized in controlling and terminating the TMI-type accident.

PBNP Emergency Operating Procedures EOP-1A, Loss of Reactor Coolant (Large LOCA), EOP-3A, Steam Generator Tube Rupture, and EOP-4A, Reactor Coolant Leak (Small LOCA), address loss of coolant accidents.

EOP-1A and 4A combined provide the operator the guidance needed in the analysis of initial symptoms and automatic safety features actuation to identify and terminate the stuck PORV accident. EOP-4A specifically addresses the stuck PORV accident and provides guidance for identifying and isolating the stuck valve.

EOP-4A does not predict SI actuation and is predicated on the fact that normal charging flow will be adequate to keep up with the loss of coolant. If this is not the case and SI actuation occurred, the accident would shift to EOP-1A. For example, if a stuck open PORV exceeds the criteria of EOP-4A, until the pressurizer relief tank rupture disk fails, ultimate symptoms of high radiation in containment and high sump A level will not provide the operator with confirmation that an intermediate loss of coolant accident is in progress. Because EOP-4A deals with many potential small LOCAs, detailed specific identification and operator action are not included in the procedure. Operator training and familiarity with the reactor coolant system are relied upon primarily in dealing effectively with the list of potential small LOCAs identified in EOP-4A.

This review, coupled with the information gained from analysis of the TMI accident, suggest that procedural improvements would be appropriate to clarify operator use of the small to intermediate sized LOCA symtom indicators.

PORV control and indication, for PBNP, provides the operator with adequate information to identify and isolate a stuck valve. The combined code safety and PORV discharge line does not have a flow detection device which could provide a more positive indication of loss of coolant without requiring the operator to observe several temperature, levels, and pressure indicators associated with the pressurizer relief tank. The need for such a flow detection device was examined. It was determined that sufficient information already exists and this flow indication device is not required.

4.2.3 Void Formation

PBNP Emergency Operating Procedures (EOPs) and Normal Operating Procedures (OPs), regarding void formation in the reactor coolant system, have been reviewed.

PBNP EOP-1A, 2A, 3A and 4A address accidents that could or do produce voids in the reactor coolant system. These procedures, however, do not make specific direct reference to voids and do not provide the operator detailed guidance for recognizing that voids have formed or how to prevent or recover from void formation. The reactor coolant system design, coupled with ESF system design, limits, controls, or recovers automatically from steam void formation. As a result of this design feature (automatic SI), details concerning void formation and control have not been included in the EOPs. All operator training emphasizes the importance of preventing void formation in the reactor coolant system and keeping the core covered with coolant. This training is considered basic to understanding the operation of a pressurized water reactor system. The importance of maintaining primary coolant system operating pressure well above saturation pressure for the existing hot leg or core thermocouple temperatures is stressed. The operator training program includes instruction on maintaining the pressurizer bubble (steam void) and preventing the pressurizer from going dry and shifting the void to the reactor vessel. Also included is instruction on solid plant operation (see also Section 4.2.4) which is a normal operating mode for PBNP startup and cooldown. A temperature-saturation pressure graph is posted in the control room and has been used by the PBNP operators as a reference for startup and shutdown operations for a number of years.

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PWR operation and the void phenomenon are thoroughly covered during initial reactor operator and senior reactor operator training programs and reviewed periodically during retraining programs. This operator training is relied on heavily to support EOPs and OPs in the prevention of void formation in the reactor core.

Normal Operating Procedures OP-3C, Hot Shutdown to Cold Shutdown, and OP-1A, Cold Shutdown to Low Power Operation, require the operator to form or collapse the steam bubble in the pressurizer. These procedures are considered adequate to prevent the possible shift of the bubble to the reactor vessel which, if it occurred, would not uncover the fuel. The precautions and limitation section does not precisely define specific conditions which could lead to void formation in the core, and this condition should be addressed.

In view of the problems encountered at TMI and the items identified for this review, procedures covering void formation, control and recovery during accidents should be reviewed; specifically the operator training programs and revisions to EOPs to guide and/or alert the operator to the possibility of void formation.

PBNP's available reactor coolant system instrumentation is similar to TMI in regard to identifying void formation. Improvement in this area could aid the operator significantly in identifying voids and should be thoroughly investigated. Section 5.3 reviews the instrumentation system in detail.

4.2.4 Termination of Engineered Safety Feature System Operation

PBNP administrative control procedures regarding termination of required Engineered Safety Feature (ESF) systems have been reviewed.

PBNP Emergency Operating Procedures EOP-1A (Loss of Reactor Coolant), EOP-2A (Steam Line Break), and EOP-3A (Steam Generator Tube Rupture) address conditions required for securing ESF system operation.

Initially for all accidents that cause SI actuation, the operator immediate action is to ensure that the systems have actuated and are providing their intended functions. If a system fails to actuate, the operator is directed to manually actuate the system. For large LOCAs (EOP-1A), there is no additional operator action required until shifting RHR pump suction to the recirculation mode of operation. For accidents where RCS pressure remains above residual heat removal system design pressure, the EOPs provide instructions for stopping the residual heat removal pumps and guidance for establishing high head safety injection (HPSI) recirculation for the LOCA.

EOP-1A assumes that the LOCA cannot be isolated and, therefore, does not provide specific instructions or set conditions for securing HPSI until the RWST has been emptied and the long term recirculation mode shift is required. The LOCA EOPs, 1A and 3A, guide the operator through the subsequent action steps to the appropriate long term cooldown recirculation mode.

Once the operator recognizes that he has the ability to terminate the LOCA (by PORV isolation as was the case at TMI), PBNP EOPs do not provide detailed specific guidance or fixed reactor coolant system conditions for securing safety feature equipment. EOP-5A, Emergency Shutdown, does reference establishing proper pressurizer level and pressure control, but again does not set specific conditions for securing HPSI.

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Clearly the intermediate size LOCA, especially that which can be isolated, creates the greatest operational problem for procedure writers. The exact conditions are widely variable and difficult to describe or predict. Compounding this difficulty is the leak which can be isolated, therefore changing the accident event category and symptoms.

To preclude generating numerous and incomprehensible procedures in an attempt to describe all the potential small to intermediate LOCAs, operator training is relied upon to identify, control and correct and/or terminate these type LOCAs.

Operator understanding of the importance of maintaining RCS operating pressure above saturation pressure and utilization of all primary system indications are the keys to securing HPSI equipment. It is important that the operator not rely on pressurizer level indication alone. PBNP is basically different from TMI in regard to HPSI design. The PBNP HPSI pump shutoff head is approximately 1500 psig as compared to 2800 psig for TMI. The TMI HPSI pump shutoff head is therefore, above the PORV and Code Safety Valve actuation setpoints, as well as system operating pressure. If the TMI reactor coolant system is allowed to completely fill with water and go solid on HPSI, these valves will operate. This unsatisfactory condition could not occur with the lower pump shutoff head of the PBNP design.

Significant recovery of pressurizer level, up to or including solid plant operation, would be the preferred condition to recover from accidents and begin the securing of SI equipment. This condition should be emphasized in the EOPs. Significant pressurizer level or solid plant operation near or at the shutoff head of the SI pumps would assure that the core is covered and system pressure is maintained with an adequate margin to saturation pressure associated with expected RCS temperatures under these conditions.

4.2.5 Reactor Coolant Pump Operation During Accidents

PBNP Operating Procedure OP-4B, "Reactor Coolant Pump Operation", sets the required plant system conditions for:

A. Starting a reactor coolant pump

B. Continued operation of a reactor coolant pump

C. Securing reactor coolant pumps.

The major purpose of this procedure is to set operating conditions that will prevent damage to the pump, pump seals and drive motor. This procedure is considered adequate to provide operator guidance for starting, stopping and continued normal operation in order to prevent pump operation during abnormal plant conditions or emergency starting.

PBNP Emergency Operating Procedures do not provide special operator guidance for continued reactor coolant pump operation with abnormal plant conditions or during accidents. In general, during accident events, and specifically in EOP-1A and 2A, these procedures require the operator to secure the reactor coolant pumps, until stable reactor coolant system and pump support system conditions have been established, at which time, the operator would operate the pump in accordance with the guidance provided in OP-4B.

Pump operation during abnormal and accident plant conditions requires additional review. The pump supplier, is currently reviewing this area and will be providing recommendations. When received, these recommendations should be evaluated and incorporated into PBNP procedures where applicable. The supplier has recommended specific changes to EOPs regarding the plant conditions necessary to require the operator to manually secure reactor coolant pumps during accidents. These recommendations should be incorporated into PBNP's EOPs where applicable (EOP-1A, 2A, 3A and 4A). These recommendations are currently being reviewed by the Procedures Subcommittee of the Westinghouse Operating Plant Utility Owner's Group.

Until all facts are clear regarding reactor coolant pump operation during accidents, specifically if there exists any accident that requires forced primary coolant circulation to prevent core damage, additional changes to existing normal and emergency procedures are not advisable. For certain cases, the safer condition appears to be securing the reactor coolant pumps during unstable accident conditions to prevent pump damage and establish natural circulation as designed. The reestablishment of forced primary coolant circulation should only be considered when plant conditions are stable and meet the existing limiting conditions for pump operation as provided in OP-4B. For other cases, continued reactor coolant pump operation appears preferable to provide more rapid cooldown of the RCS. Accordingly competent operators should retain options with respect to reactor coolant pump operation.

4.2.6 Uncontrolled Release of Reactor Coolant from Containment to Auxiliary Building

Conditions that existed at TMI surrounding this problem are still not clear; however, it is assumed for this analysis that operator inaction, administrative procedures, and design features contributed to the problem. A similar combination of events is not likely at PBNP due to:

A. System Design (manual draining only),

B. Containment sump drain isolation on SI signal, and

C. Administrative controls on the operation of waste holdup tank.

The PBNP containment sump is drained by manual operation only. The drain line is equipped with two isolation valves. One valve is normally open and the other is normally closed. Each valve receives a containment isolation signal upon safety injection actuation. To drain the sump (by gravity) to the auxiliary building sump at the -19 ft. elevation, the control room operator must open the closed valve and hold the spring-loaded switch in the open position while the actual draining is accomplished. This switch returns to the closed position when released. Valve position indication is provided in the control room for each valve. The auxiliary building -19 ft. sump is located at the lowest elevation of the building and is automatically pumped to the waste holdup tank. The automatic pump operation can be monitored in the control room (pump running lights only). The waste holdup tank is equipped with two level alarms: a fixed high level alarm at 85% of capacity and a variable level alarm. The variable level alarm is manually set at approximately 5% above the actual tank level each time the variable level alarm is received and following transfer of fluids to other tanks. The variable level alarm notifies the operator that water is being added to the tank and, if an inleakage condition existed, would alert the operator to the condition before reaching the high level fixed alarm.

This design approach is adequate to prevent automatic draining of the containment sump and to prevent the overfilling of the holdup tank.

4.2.7 Control of Hydrogen in Containment

The design of the PBNP Post-Accident Containment Ventilation System is predicated upon the analysis described in Appendix D of the Final Facility Description and Safety Analysis Report (FFDSAR). The operation of the system is considered an emergency condition and Emergency Operating Procedure 11-A defines the required valve lineups and operator actions. This procedure is considered adequate to control the concentration of hydrogen gas that could accumulate inside the containment during the design basis accident.

The accumulation of significant amounts of hydrogen gas inside the reactor coolant system is precluded by Emergency Operating Procedures and basic system design. While existing procedures do not specifically address dealing with hydrogen gas in the reactor coolant system, its ability to accumulate to hazardous levels is inherently prevented by system design. Any hydrogen gas that may come out of solution or be generated will be removed from the reactor to the pressurizer vapor space where it can be vented in a controlled manner. The design of the surge line between the reactor coolant loop and the pressurizer inlet is such that any gases being carried by the fluid system can leave the top of the loop piping and rise into the pressurizer because the pressurizer is elevated such that the surge line has an upward slope between the loop and the pressurizer inlet nozzle. Gases that might accumulate in the top of the reactor vessel are continually being taken back in solution at the interface of the gas and coolant and removed via letdown or through the pressurizer.

The PBNP Normal and Emergency Operating Procedures have been reviewed and are considered adequate at this time. Further reviews should be conducted as more detailed information concerning hydrogen sources and production, gas transport, accumulation, and recombination during the TMI accident becomes available.

The Plant Procedure regarding control of hydrogen in containment was reviewed relative to the following areas:

A. Containment Circulation

B. Recombiners

The PBNP Emergency Operating Procedure, "Post Accident Containment Ventilation System", has been reviewed and is considered adequate to satisfy the design requirements.

The PBNP system does not provide for the use of hydrogen recombiners. The analysis described in Appendix D of the PBNP FFDSAR demonstrates that the controlled venting of the containment into the auxiliary building exhaust system (including charcoal filters) is adequate to meet the design basis accident.

The post-accident containment ventilation system piping and valves have been installed in such a manner that an operator can perform the necessary sampling and operational actions required during the accident.

The vent line and the sample line both originate in the dome of the containment where hydrogen would accumulate and the operation of the Containment Air Cooling System provides adequate recirculation within the containment. Each containment is equipped with an external service air connection which can be used to pressurize the containment to a maximum of 3 psig to provide the motive force to remove the gases in the dome of the containment (see Section 5.2.3).

4.2.8 Control and Monitoring of Natural Circulation

PBNP procedures have been reviewed to determine if guidance is provided to properly recognize, initiate and control the reactor coolant system in a natural circulation operational mode.

This review shows that PBNP does not have a procedure which specifically addresses the natural circulation mode of operation.

Although PBNP is designed for natural circulation and functionally tested during startup operations, a retest of this mode of operation has been conducted since the TMI accident. This mode of operation requires additional review of the test data and that necessary procedures be developed or existing procedures be revised to provide the necessary guidance to recognize, initiate and control natural circulation.

4.3 TRAINING CONSIDERATIONS

Significant events that occurred at TMI have been reviewed with the PBNP licensed operating personnel and plant staff. This review process should be ongoing as additional information is received and, to date, has included the following:

A. TMI Accident Sequence of Events

B. Void formation, identification and control

C. Operational consequences of isolating both trains of the auxiliary feedwater system

D. Power operated relief valve, PORV isolation valve, and pressurizer relief tank operation

E. Natural circulation initiation, monitoring and control

F. Required operating conditions in the reactor coolant system prior to securing safety features equipment following SI actuation

G. Small LOCA evaluation identifications using multiple key plant indications

H. Requirements for draining or venting the reactor containment building following a LOCA

I. NRC notification and emergency plan initiation

J. Post accident TMI operational problems

PBNP training has relied on a thorough classroom and "dry run" walk through training approach to prepare operators for accident identification, control panel familiarity and overall understanding of the basic accidents analyzed for a PWR. This training approach places emphasis on the operator's thorough understanding of all reactor plant systems. This approach also requires operators to evaluate multiple key plant indicators in order to evaluate accident conditions. Simulator training has not been used to date to train control operator candidates. However, PBNP had used simulator training for licensed operators prior to the TMI accident as part of their retraining program. This is a program of emergency procedure and emergency operation training. This simulator training will be provided for retraining once every two years and for initial license candidates. To date, approximately 20% of the licensed operators have received this type of training.

PBNP management has always recognized the need for and provided a continuous upgrading of licensed operator training. This need is not tied to the TMI-type accidents, but are more a result of continuous upgrading of plant systems. Without a flexible program to deal with these constant changes, the training would rapidly become obsolete. This flexibility is reflected in a recent reorganization of the Plant Training Division, which added a licensed Shift Supervisor to the Training Staff who supports and assists the Plant Training Supervisor with licensed operator training. PBNP training programs are being reevaluated and plans are underway to revise and update licensed operator training programs. The revisions reflect the current as-built plant system conditions and include

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revised operating methods. Additionally, the initial lessons learned from the TMI accident should be factored into the PBNP training programs. Specifically, the following topics should be thoroughly covered:

A. Procedure revisions resulting from TMI accident evaluation currently in progress.

B. Small and intermediate size LOCA sympton identification and immediate corrective action.

C. Consequences of isolation and/or premature termination of safety feature system operation.

D. Natural circulation in the primary coolant system.

The Task Force review has concluded that the ongoing PBNP licensed operator training program, the recent training division reorganization and upgrading, and the initial TMI accident review provides reasonable assurance of a competent operating staff familiar with and understanding of the TMI events.

4.4 CONCLUSIONS AND RECOMMENDATIONS

This review has determined that PBNP procedures are adequate to prevent a TMI-type accident. PBNP procedures have demonstrated their adequacy during actual related events as summarized in Section 3.6. The recommendations resulting from this review are made to improve the operational capability of PBNP and are not needed to correct any major deficiency. The Task Force accordingly recommends the following:

A. Revise EOP-1A, 2A, 3A, and 4A to more fully deal with the identification, control, and recovery from void formation during the emergency event. EOP-4A should be revised to include more detailed guidance on identifying and isolating leaks via the power operated relief valves.

B. Develop a new EOP to deal specifically with intermediate size loss of primary coolant accidents or expand details to include such events in the existing procedures. This procedure or revision should cover, as noted above, the identification, control, and recovery from void formation and also specific conditions for securing Engineered Safety Feature systems equipment.

C. OP-3C, Hot Shutdown to Cold Shutdown, and OP-1A, Cold Shutdown to Low Power Operation, should be revised to include precautions and limitations for operation to prevent void formation. Caution notes should be added when collapsing or forming steam bubbles in the pressurizer to advise operators of conditions necessary to prevent void formation in the reactor vessel area.

D. Upgrade auxiliary feedwater system indication by providing a ready status panel for the system on the Control Room Safety Feature Panel C01, similar to that existing for other safeguards systems, and by providing individual train flow indication in the control room.

E. The current program for simulator training of operators in the area of emergency operation should continue.

F. Any additional TMI information should be reviewed with the PBNP licensed personnel as has been done previously.

In addition, the Task Force has reached the following conclusions regarding the TMI accident, the Babcock & Wilcox reactor coolant system design, and TMI operator actions:

A. TMI administrative control procedures and system design failed to prevent both trains of auxiliary feedwater system from being isolated during normal operation. Additionally, the Safety Feature Control system failed to warn operators of this condition.

B. TMI operators did not recognize the failure of the relief valve to reclose or the timely need to isolate the stuck electromatic relief valve to prevent formation of voids. Additionally, the electromatic relief valve position indication failed to warn or provide the operators with accurate indication that the valve did not close. (Termination of the RC leak would have allowed the operators to reestablish normal system pressure control and thereby limit or prevent void formation.)

C. TMI operators failed to recognize and properly control and/or prevent void formation in the RC system. Additionally, the TMI control system design failed to provide the operator with void formation alarm indication. (The operators had lost the "big picture" and apparently were using pressurizer level to make all or most operating decisions.)

D. TMI administrative control procedures failed to prevent operators from prematurely terminating HPSI. Additionally, the TMI operators failed to recognize that conditions existing in the RCS indicated that HHSI was still required, as a reactor coolant system leak was in progress and voids were (or had) formed in the RC system.

E. TMI administrative control procedures and control system design failed to prevent an uncontrolled release of radioactive coolant from the containment to the auxiliary building during the accident. Additionally, TMI operators failed to recognize that the reactor coolant was being pumped to the auxiliary building from containment and failed to terminate the transfer.

F. TMI administrative control procedures and system design failed to prevent the overfilling of the waste collection tank. Operators failed to recognize the condition and terminate the source before a spill occurred.

G. The B&W reactor coolant system design cannot insure adequate natural circulation once a steam void, which uncovers the hot leg, has been allowed to form in the reactor vessel. This design deficiency, coupled with operator failure to recognize that voided conditions existed in the RCS, recognize that a LOCA was in progress, maintain needed HPSI, and maintain forced primary coolant circulation, set up the conditions necessary to uncover the core. This resulted in significant fuel failure.

SECTION 5

REVIEW OF POINT BEACH NUCLEAR PLANT DESIGN FEATURES

5.1 INTRODUCTION

This section addresses the Task Force's assignment to "Determine for Point Beach Nuclear Plant whether any equipment, design, system .... should be modified or changed as a result of the Three Mile Island accident."

The PBNP plant systems and equipment involved in a TMI-type accident were investigated and the following summarizes the results of this evaluation.

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5.2 PLANT SYSTEMS AND EQUIPMENT REVIEW

5.2.1 Venting the Reactor Vessel Head and the Pressurizer

Venting of the PBNP reactor vessel head can only be accomplished in a shutdown mode where personnel access is possible to the Control Rod Drive Mechanism housings or the reactor vessel vent valve. The PBNP pressurizer can be vented through the pressurizer vapor space sample line or the power operated relief valves (PORVs) if needed.

The PBNP reactor coolant system design has provided a means of restricting the size of a gas bubble in the reactor vessel head. The reactor vessel outlet nozzles connect to the horizontal section of piping which then rises and enters the bottom of the U-tube steam generators. On the loop that connects the pressurizer to the RCS, the surge line connection comes off the top of the hot leg pipe and then maintains an upward slope until it enters the bottom inlet nozzle of the pressurizer. This design provides a method by which any gases that enter the hot leg piping will migrate to the pressurizer where they can be vented in a controlled manner.

It is certainly feasible to install a reactor vessel vent valve that could be remotely operated, and the use of an existing spare head penetration is a logical location. Before deciding where the discharge of a reactor vessel vent valve should be directed, it is necessary to determine under what plant conditions it would be used. It would appear that the only time venting the reactor vessel head would be desirable would be during a small LOCA, such as the TMI accident. It is possible that someday a small pipe break, which cannot be isolated, will occur (e.g., failure of a pressurizer safety valve to reclose). If a loss of offsite power occurs during the accident, it is possible that the operators would be unable to rapidly depressurize the reactor coolant system to the point where the Residual Heat Removal System could be placed in operation. With the present PBNP design, the operators can keep the RCS pressurized above the saturation pressure of the RCS and use natural circulation to cool the RCS and core. In any event, there is already in existence a small LOCA and the containment is receiving the spillage of reactor coolant, so there is no useful purpose served by piping the discharge of a reactor vessel vent valve to the pressurizer. If a reactor vessel vent is provided, it should be directed either to the containment or to the Pressurizer Relief Tank (PRT), not to the pressurizer.

In addition, no existing penetrations are available on the pressurizer and the difficulties associated with installing such a penetration on a carbon steel stainless steel clad vessel would be formidable. The connecting piping between the vent valve and the pressurizer also would have to be designed to the same requirements as the Reactor Coolant System, yet be capable of removal during the annual refueling outage to permit removal of the reactor vessel head. Although the PRT is a stainless steel vessel, no existing penetrations are available and a new penetration would have to be made to accommodate a reactor vessel head vent. The same integrity of design limits and removal capabilities would also be required if the vent were to be connected to the PRT. The PRT is designed to accept the PORV and safety valve discharges, which already provides RCS vent capability via the pressurizer. Thus, discharge directly into the containment atmosphere appears most feasible if it is determined that such a vent is necessary.

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A reactor vessel vent valve, or valves, could be similar to the present PORVs on the pressurizer and could be protected by an upstream motor operated valve for isolation purposes, if required, and if permitted to discharge directly into the containment atmosphere, could become an integral part of the reactor vessel head equipment.

The existence of the two 4-inch decontamination valves on the hot legs of the PBNP RCS provides another possible method of controlling a small to intermediate LOCA. Remotely operated valves could be installed on these connections which would provide a means of depressurizing the RCS. If the solution to the small LOCA is to make it a large one that will permit depressurization and subsequent residual heat removal system operation, then this alternative should be further investigated. The original PBNP design included these valves with the specific consideration of their use as reactor coolant system blowdown valves during LOCA conditions.

5.2.2 Sampling Considerations During Accidents

The original design criteria of the PBNP recognized the possible effects of highly radioactive liquids and gases based upon the assumption of one percent fuel failure. The routing of piping systems, shielding, valve location and sampling points was predicated upon the requirements that the operators have access to equipment that requires action or attention during normal operation for recirculation of containment water through the residual heat removal system following a LOCA.

It is suggested that the PBNP Staff be informed of the problems encountered at TMI and that they be instructed to bring to management's attention any conditions they believe require correction. The trained chemists, health physicists, and operators are the most knowledgeable individuals concerning equipment layout and sampling points. Properly instructed, they should be capable of reviewing the PBNP equipment during the performance of their regular duties.

5.2.3 Dealing with Hydrogen Following a LOCA

The design of the PBNP Post-Accident Containment Ventilation System is predicated upon the analysis described in Appendix D of the Final Facility Description and Safety Analysis Report. The operation of the system is considered an emergency condition and an emergency operating procedure defines the required valve lineups and operator actions. This procedure is considered adequate to control any concentration of non-condensible gases, such as hydrogen gas, that could accumulate inside the containment during the design basis accident. The accumulation of significant amounts of hydrogen gas inside the reactor coolant system is precluded by emergency operating procedures and basic system design. While existing procedures do not specifically address dealing with hydrogen gas in the reactor coolant system, its ability to accumulate to hazardous levels is inherently prevented by system design. Any hydrogen gas that may come out of solution or be generated will be removed from the reactor coolant system via letdown purification in the gas strippers or will migrate to the pressurizer vapor space where it can be vented in a controlled manner. The design of the surge line between the reactor coolant loop and the pressurizer inlet is such that any gases being carried by the fluid system can leave the top of the loop piping and rise into the pressurizer, because the pressurizer is elevated such that the surge line has an upward slope between the loop and the pressurizer inlet nozzle. Gases that might accumulate in the top of the reactor vessel are continually being released and taken back into solution at the interface of the gases and coolant. They can be removed from the coolant via letdown or through the pressurizer.

The PBNP normal and emergency operating procedures have been reviewed and are considered adequate in respect to hydrogen gas formation and handling at this time. Further reviews will be conducted as more detailed information concerning the TMI accident become available.

The present PBNP design vents the containment dome through the auxiliary building exhaust system (including roughing, HEPA, and charcoal filters) to the atmosphere. While this is totally acceptable as defined by our current license and described in Appendix D of the FFDSAR, the TMI accident clearly demonstrates that greater emphasis may be appropriate to minimize release of <u>any</u> radioactive gases from the plant during an accident.

Provisions for installation of a temporary recombiner were included in the original PBNP design. PBNP could be modified to accommodate a permanently installed hydrogen recombiner system which would remove the hydrogen and return the radioactive gases to the containment. Further engineering study should be performed to determine requirements for such a system. It may not be necessary to actually have a recombiner on site, however, portions of the system to facilitate later installation should be provided.

5.2.4 <u>Auxiliary Feedwater System</u>

Full flow testing of the auxiliary feedwater water pumps on a monthly basis is feasible; however, it is not necessary or desirable for the following reasons:

A. The lack check valve in the auxiliary feedwater system line is physically located as close as possible to the point where the line enters the main feedwater line and very near the feedwater inlet nozzle on the steam generator. This location was specified in the original PBNP design so as to minimize the possibility of an auxiliary feedwater system piping failure resulting in a secondary side blowdown of the steam generator.

   In the PBNP design, the last check valve exists in a high temperature main feedwater system environment, whereas the valve, in those systems where it is remote from the main feedwater flow, is in a much cooler environment. Full flow monthly testing would include a thermal shock on the valve and, although the system would function, the maintenance requirement on the valve would increase.

   There has never been an instance of failure to obtain auxiliary feedwater flow at PBNP in over fifteen reactor years of operation.

B. The only purpose served by monthly full flow testing is to verify the performance of the pump. The monthly test on minimum recirculation flow provides a discharge pressure that is compared with the pump capability curve. Full pump capability is determined during the annual refueling.

Recommendations for full flow testing appear to be a defensive move to demonstrate some response to the TMI accident. It is not necessary and, in fact, is undesirable for the PBNP.

5.2.5 Natural Circulation Capability of the Primary System

The natural circulation capability of the plant has been proven to be completely acceptable during plant testing performed to measure specifically the amount of natural circulation flow and during actual operation when natural circulation was used to remove core decay heat. Appendix A, which is attached to this report, provides a summary of testing and operational experience with natural circulation. It is concluded that the design of the PBNP primary system is such that natural circulation occurs in sufficient magnitude to remove core decay heat via circulation and heat removal through the steam generators.

The review of natural circulation capability identified two areas where improvements can be made to improve the operator awareness of the initiation and continuation of natural circulation. This first area has already been addressed in Section 4.2.8 dealing with the instructions in procedures which guide the operator in his control and monitoring of natural circulation. The second area deals with the instrumentation that is available to the operator which enables him to monitor natural circulation. The presently installed instrumentation does not provide complete information to the operator to assess easily the initiation of natural circulation. The only signals available to the operator on the control board are steam generator conditions which indicate if the steam generator is steaming and removing heat and the temperature of the cold legs which by themselves under natural circulation do not give the operator much information. Also available to the operator are the temperatures from the thermocouples located at the outlet of selected fuel assemblies. This information is obtained from the computer or a manual readout device located in racks behind the main control board. The information an operator needs is a core outlet or hot leg temperature displayed on a recorder so the operator can see this temperature increase to provide the driving force for natural circulation and then stabilize as natural circulation is established. Details of this instrumentation are described in Section 5.3.2.

5.2.6 Steam Condensing Capability of the Steam Generators

For breaks that rely on the steam generator for heat removal, the energy transfer may be accomplished in several ways. One stable condition consists of a flow of two-phase or subcooled fluid around the steam generators constantly throughout the transient. This natural circulation mode of heat removal is predicted to occur for very small breaks. Another effective mode of heat removal is that of condensation of steam, with the condensed liquid either being carried over the top of the steam generator or falling back down the steam generator tubes and back through the hot leg. These modes of heat removal have been modelled by the NSSS designer in the small break code, WFLASH. A description of the WFLASH steam generator heat transfer model is included in WCAP-8200, Revision 2. However, in the modelling no condensed liquid is considered to drain back into the hot legs and core. This conservative assumption was imposed on the analysis by the NRC Staff during their review of the small break ECCS Evaluation Model. This is accomplished by modelling the hot

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side of the steam generator primary as a homogeneous control volume. Therefore, in the small break analyses, all condensate is carried over the top of the tubes. This modification results in a conservative calculation of core uncovery and PCT for small break transients.

It is predicted that liquid flow natural circulation is interrupted for Westinghouse plants for breaks somewhat greater than a 1" equivalent diameter hole. The steam generator tubes begin to drain for breaks of this size. This drainage then decreases heat removal due to a reduction and eventual stoppage of the liquid natural circulation mode. As the tubes drain, loop mass flow rate drops rapidly. However, heat removal continues at a rate capable of removing all decay heat through steam condensation. A detailed review of the draining phenomenon, as calculated by WFLASH, indicates a smooth hydraulic transition from liquid flow natural circulation to condensation. The hydraulic transition tends to smooth out significantly the changes in flowrate that may exist locally in the steam generator. WFLASH predicts adequate heat removal through the transition period, with no interruptions or significant decreases in heat removal rate. This transition prediction has been questioned and additional work may be needed to verify the adequacy of the modelling and conservatisms. The presently installed instrumentation does not provide complete information to the operator to determine easily that the transition is in progress or has changed from the liquid flow natural circulation mode of heat removal to the steam condensing mode. Temperature indications correlated with pressure allow a determination that the pressure has decreased below the saturation point and steam has formed somewhere in the system. However, this may take place even during natural circulation. The temperatures of most interest in such events would be from the existing core thermocouples or a direct reading from hot leg instrumentation, similar to the current cold leg, wide range RTDs. A display of selected temperatures on a recorder may indicate with greater certainty the transition with either an increase or instability in indicated values. Any hot leg temperature instrumentation would be uncovered as the vessel water level drops and the steam generator tubes drain. The core exit thermocouples would be uncovered just prior to uncovering the core. The value of their indications after this time would be suspect. Flow indication would be non-existent although actual RCS conditions would provide reflux of the condensed steam in both the hot and cold legs. As in natural circulation, the only indication of continued heat removal are the steam generator conditions as described in Section 5.2.5 above.

In conclusion, adequate heat removal can be provided by the steam condensing capability of the steam generators.

5.2.7 Utilization of Steam Generators to Cool the Primary System Below 200°F

Natural circulation of the RCS should continue as long as there is a means of removing heat from the system in the steam generators. The normal method is to cause the water in the secondary side of the steam generator to undergo a change of state by turning into steam with its subsequent removal to the turbine generator condenser. The effectiveness of this method decreases rapidly as the RCS hot leg temperature approaches the atmospheric pressure saturation temperature of 212°F and is not a viable means of heat removal below 250°F (15 psig). The secondary side of the steam generators could be used as a liquid to liquid heat exchanger by filling the secondary side solid and directing the outlet to the condenser. In this mode, the steam generator could be utilized to reduce the RCS temperature below 200°F; however, consideration must be given to the following:

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A. It must be assumed that access to the containment is not possible and, as a result, it is impossible to install the steam line hanger blocking devices which would prevent deflection of the water-filled piping. Thus, the flow of water out of the top of the steam generator must be controlled so that the horizontal sections of steam piping are not overloaded by the weight of the water. This requires an open path all the way to the condenser (or other type of heat exchanger) and careful control of the rate of feedwater addition.

B. The presence of primary to secondary leakage must be considered.

A cursory review of the main steam lines indicates that it should be feasible to install a connection in the area of the sacrificial flange hear the low point of the line in the turbine hall. This would permit the installation of an appropriately sized piping system that could connect the main steam line to the condenser through a new penetration or perhaps through a connection in an existing penetration. Manual isolation valves could be used for isolation during normal operation.

5.2.8 Radiation Considerations of Piping Systems in the Auxiliary Building During and Following a LOCA

Shielding throughout the plant is designed to assure safe operation with a 1% fuel defect level. This design criterion ensures reasonable radiation levels for the various areas of the plant with consideration of appropriate occupancy factors for each area. The same design criterion is applied to all major modifications. Further action is not required for normal plant operation. However, due to problems that TMI has had with respect to reactor coolant system sampling and auxiliary building accessibility since the accident, further examination of radiation considerations following a LOCA should be continued.

In the analysis of a major loss of coolant accident (LOCA), it is assumed that some breach of fuel cladding integrity occurs with the resultant release of 100% of gap activities to the primary coolant. Further release of these activities to the containment is assumed, and adequate design features are providing to mitigate potential offsite dose consequences and ensure the public health and safety. Similarly, adequate ventilation, filtration, and shielding are provided to ensure the habitability of the control room throughout the recovery period following a major accident. In other portions of the plant, particularly in the Auxiliary Building, post-accident radiation levels may exceed those corresponding to normal operation of the 1% fuel defect level.

This does not imply that the Auxiliary Building would be inaccessible or that there may be additional operational complications afforded by the potentially elevated radiation levels. It may, however, be appropriate to perform some additional review to determine the acceptability of radiation levels during post-accident recovery operations in the following areas:

A. The C-59 control panel, particularly to determine any potential effect from high head safety injection operation;

B. Safety related motor controls in the vicinity of the charging pumps;

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C. The small waste evaporator control panel and the two boric acid evaporator control panels in the vicinity of the spray and high head safety injection pumps;

D. The sample rooms;

E. The residual heat removal system manual valve gallery; and

F. The charging pump and pressurizer heater local control stations.

It should be noted that there are a number of differences between Point Beach Nuclear Plant and Three Mile Island to either mitigate or preclude the same operational complications in the Auxiliary Building which hampered recovery operations at Three Mile Island. The first of these consists of the several significant design feature differences which preclude the occurrence of an identical accident sequence at Point Beach Nuclear Plant, as discussed elsewhere in this report. The second consists of the several significant design differences which preclude the flooding and contamination of the auxiliary building in the manner experienced at Three Mile Island; again these are addressed elsewhere in this report. The third major difference is the location of Residual Heat Removal (RHR) pumps and piping. At PBNP, the RHR pumps are located at the -19 ft. elevation, an isolated area whose radiation levels would not affect operations elsewhere in the auxiliary building and, in which, any liquid leakage is easily confined and handled. RHR piping is reasonably direct and does not course throughout the building. However, additional review of RHR pump cubicle ventilation is appropriate to determine that potential gaseous leakage from RHR pump seals is routed in a manner which will not have a significantly adverse effect on airborne radioactivity levels elsewhere in the building.

5.3 INSTRUMENTATION SYSTEM REVIEW

5.3.1 Pressurizer Low Pressure Plus Low Level Coincidence

One of the actuating signals for safety injection is 1 out of 3 pairs of coincident pressurizer low pressure plus low level as shown in Figure 5.3-1. As a result of recent events at TMI, the NRC Staff has directed that the level signal be deleted as an input to this circuit. It is thought by the NRC that pressurizer level is not a true indicator as to the need for safety injection.

As an interim measure, the NRC directed that the test switches for the three low level bistables be placed in the trip condition on each unit, thereby creating a 1 out of 3 actuation on low pressure only. A review of this situation showed that on a loss of AC, both units would receive a safety injection signal. PBNP is not designed to be able to handle simultaneous safety injection actuations on both units. This problem was eliminated by placing the test switch back to the normal position on the channel that is supplied by the "white" instrument bus on each unit, thereby creating a 1 out of 2 actuation on low pressure.

A modification request was then issued and implemented which changed the original actuation matrix to a 2 out of 3 low pressurizer pressure actuation circuit as shown in Figure 5.3-2.

The above circuit was analyzed as to its compliance with IEEE-279. It was found that since the pressurizer pressure signals are also used for control purposes, the circuit does not meet the following paragraph:

> 4.7.3 Single Random Failure - Where a single random failure can cause a control system action that results in a generating station condition requiring protective action and can also prevent proper action of a protection system channel designed to protect against the condition, the remaining redundant protection channels shall be capable of providing the protective action even when degraded by a second random failure.

To enable the circuitry to meet the above paragraph, the power operated relief valve interlocks were changed from a setpoint of 2185 psig to a setpoint of 2335 psig. This makes the actuating circuit for each power operated relief valve into a 2 out of 2 high pressure actuation and assures compliance with paragraph 4.7.3.

5.3.2 Incore Thermocouples and Hot Leg Temperature

A. Incore thermocouples - The present incore thermocouple measurement system consists of the computer and an indicator located in the racks behind the main control board. In the event of a loss of the computer or during an accident when the computer may be overloaded, the indicator is the only source of incore temperatures available to the operator. The present range of the indicator is acceptable for normal operating conditions but not for temperatures that may be seen during certain types of accidents. Also, it is inconveniently located and is awkward to use. A system with an appropriate range and located in a more convenient location is being investigated by the PBNP staff.

B. Hot Leg Temperature - Core average temperature and loop temperature differences are presently available only through the computer. Hot leg temperature can be calculated from ΔT and T_{avg} as measured by RTDs located in the bypass loops. In the event of a loss of reactor coolant flow, these measurements would not be correct because flow through the manifold is so low there can be significant cooling from radiant heat losses. The PBNP staff is investigating a system to directly indicate hot leg temperature on the main control board using existing RTDs in wells located directly in the hot leg. A recommendation is made in Section 5.5.E to provide the operator with a record and an indication of reactor coolant system pressure and saturation pressure. Cold leg temperature, as measured by RTDs in wells located directly in the cold leg, is presently recorded on the main control board.

5.3.3 Actuation, Isolation and Reset Features

Automatic safety injection is presently actuated by the following signals which all utilize a 2 out of 3 logic:

A. High containment pressure

B. Low steam line pressure (SG "A")

C. Low steam line pressure (SG "B")

D. Pressurizer low pressure (see Section 5.3.1)

Once safety injection has been actuated, it may be reset after two minutes by operator action even if one or more of the above actuating signals are still present. Automatic initiation of safety injection will not recur until all of the actuating signals clear. Then, automatic safety injection will be reactuated when required by the signals. A manual actuation button is also available which will override the above block. A recent modification has provided circuitry that will remove the block on a loss of AC power so that resequencing of automatic restart of the safety injection will be reinitiated.

Containment ventilation isolation is actuated by an automatic or manual safety injection signal. The containment purge supply and exhaust valves are also closed on high containment radioactive particulate and gaseous signals or by a containment ventilation isolation actuation. The resetting of safety injection does not reset containment ventilation isolation. Due to other NRC concerns, the valves are presently locked shut and can only be opened during a cold shutdown.

Containment isolation is actuated by an automatic safety injection signal or by manual operator action. Containment isolation currently has a modification in progress such that it can be reset manually only after resetting of safety injection. The following systems which could result in the purging or venting of radioactive gases or liquids out of the primary containment are isolated by the containment isolation signal:

A. Containment sump drain

B. Pressurizer relief tank and reactor coolant drain tank vent

C. Pressurizer relief tank and reactor coolant drain tank vent

D. Pressurizer relief tank gas analyzer sample line

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E. Reactor coolant drain tank gas analyzer sample line

F. Normal reactor coolant letdown line

G. R11 and R12 radiation monitor line

H. Reactor coolant pump seal return line

I. Pressurizer steam and liquid sample lines

J. Reactor coolant system hot leg sample line

Additional systems which are isolated by the containment isolation signal are:

A. Auxiliary charging line

B. Instrument air line

C. Reactor makeup water line

D. Nitrogen header

E. Component cooling from the excess letdown heat exchanger line

A review of the above systems indicates no needed design change, other than that the modification already made to actuate safety injection using 2 out of 3 low pressurizer pressure signals.

5.3.4 Pressurizer PORV Position and Flow Indication

The following indications are available to the operator for determination of the status of a pressurizer power operated relief valve:

A. Valve position indication on the front of the main control board for the power operated relief valves and the associated isolation valves. The full open and fully closed valve position indication lights are operated by limit switches mounted on the valves.

B. Valve discharge header temperature indicator (meter) located on the front of the main control board with a high temperature alarm. The presence of a high temperature and alarm would indicate that one or both PORVs have opened and admitted steam to the common discharge header.

C. Pressurizer relief tank temperature, pressure, and level are indicated on the front of the main control board, each parameter having a high alarm. An increase in any of these parameters and a high alarm would indicate a relief from the pressurizer.

In addition, valve discharge header temperature is indicated on the front of the main control board for each pressurizer safety valve, each having a high alarm. This would enable the operator to determine if a pressurizer safety valve is open.

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5.3.5 Pressurizer Level Instrumentation

The pressurizer level measurement system consists of four individual channels. Three of the channels are calibrated for normal operating conditions at 2250 psia and the fourth channel is calibrated for cold shutdown conditions.

The cold shutdown channel consists of a differential pressure (d/p) cell type transmitter mounted 44.5" below the lower tap on the pressurizer. The high and low taps are 275" apart. The high side of the d/p cell is connected to the low tap and the low side is connected to the high tap. There is a condensate pot located at the high tap. Even though the purpose of this channel is to provide level indications at hot shutdown, it can be used as a check on the other three channels at normal operating pressure by the use of a comparison curve.

The three normal operation channels consists of d/p cell type transmitters connected similar to the cold shutdown channel except that they are equipped with sealed reference legs. This consists of a bellows seal unit located about 10 inches below the condensate pot. The tubing between the bellows seal unit and the transmitter low side connection has been filled under a vacuum with degassed water. The purpose of the sealed system is to prevent the water from being blown out of the reference leg by dissolved gases coming out of solution in fast depressurization. If the water above the sealed bellows were blown out, it would cause an error of less than 4% high.

It appears that the above system will give reliable readings at normal operating pressure (2250 psia), but will be slightly in error at any other pressure. The PBNP staff is generating curves to show the amount of error and to assist the operator in accommodating this error at various pressures.

5.3.6 Containment Sump Water Level Instrumentation

A. Sump A Level Indication - Sump A is located in the floor of the incore-instrumentation tunnel. The level measurement system consists of a displacer-type transmitter located in the sump with an indicator and high alarm located on the main control board.

B. Sump B Level Indication - Sump B is located in the bottom of the containment. The floor is the bottom of the sump. Four sets of level switches are located at 3', 5', 7' and 9' elevations above the floor. Each switch has an indicating light on the front of the main control board. This system has no automatic function. The total volume of water at each elevation is in the process of being calculated.

5.3.7 Reactor Vessel Level Instrumentation

The present reactor vessel level measurement system, used only at cold shutdown, consists of a d/p type transmitter which indicates on the main control board. It is also input to the computer which provides alarming. The high side of the transmitter is connected to a tap on one of the cold legs and the low side is connected to the vessel vent. The vent connection is only connected at cold shutdown. A review of this system has shown that it cannot be adapted to be used at normal operating conditions.

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5.3.8 Incontainment Radiation Monitoring Instruments Following a LOCA

Point Beach Nuclear Plant is not equipped with post-accident, incontainment radiation monitoring devices. Such instrumentation is neither appropriate, desired, nor needed, since there is no conceivable purpose for such information from the viewpoint of either public health and safety or operation and recovery.

One monitoring device was provided at the top of the containment at Three Mile Island. According to published reports, the instrument indicated 30,000 R/hr. Since this level is not consistent with other known facts regarding the accident, it is concluded that the monitor failed. In any event, it served no useful purpose other than appealing to some prurient interests and adding to the sensationalism of the event.

Containment atmosphere radioactivity concentration data can be useful for both predicting offsite consequences and for providing in-plant radiological data, particularly when containment entry is desired. This information is obtainable by sampling the containment atmosphere, provisions for which exist at PBNP. For example, the post-accident containment ventilation system is available as a sampling location. Direct radiation readings for post-accident containment entry are best obtained by the prudent and cautious use of portable instrumentation at the outer hatch, in the airlock, at the inner hatch, while cracking the inner hatch, while entering, and while inspecting. Remote instrumentation is not needed; if it were available, it would not be trusted, and primary information would still be obtained from portable instruments.

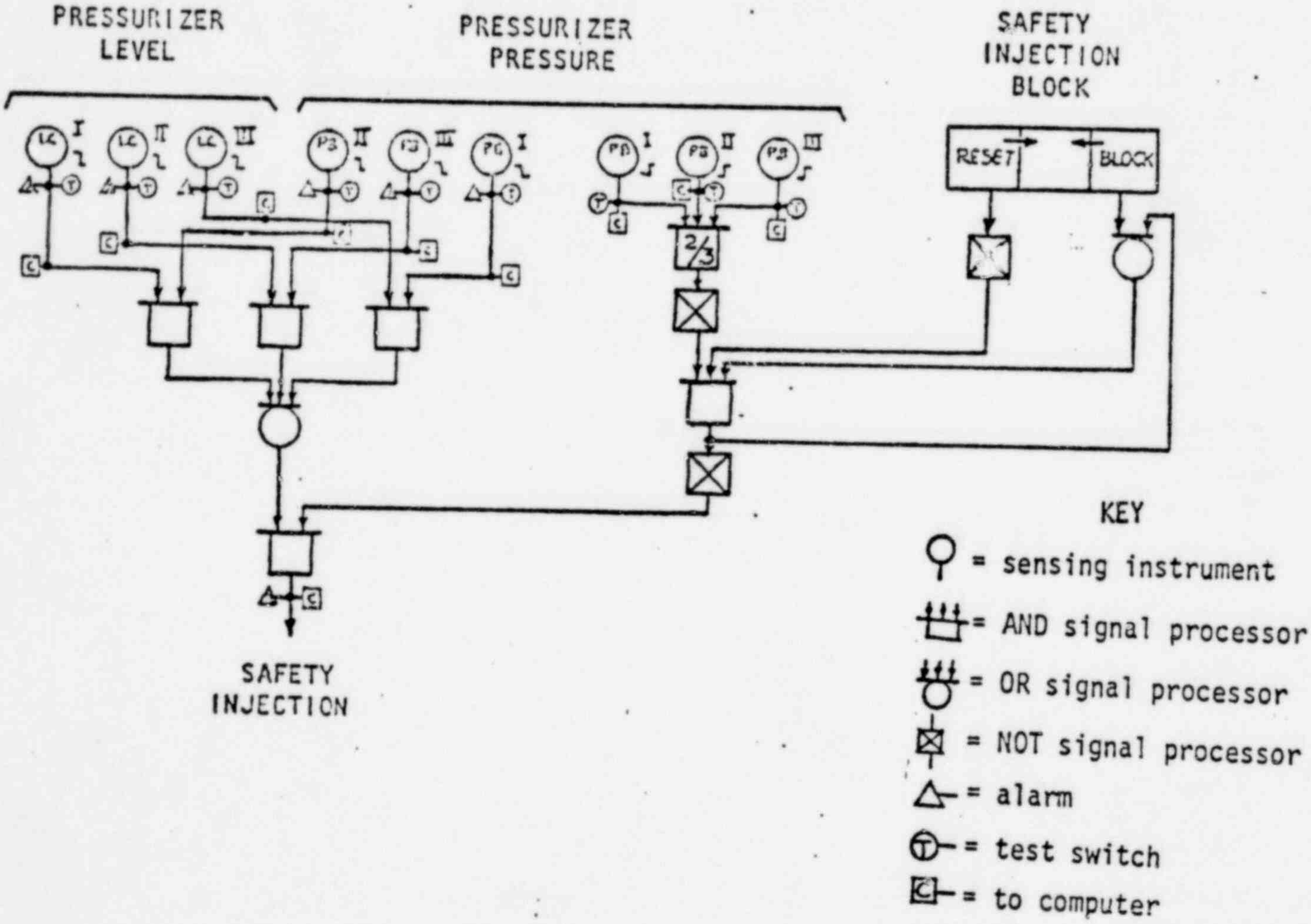
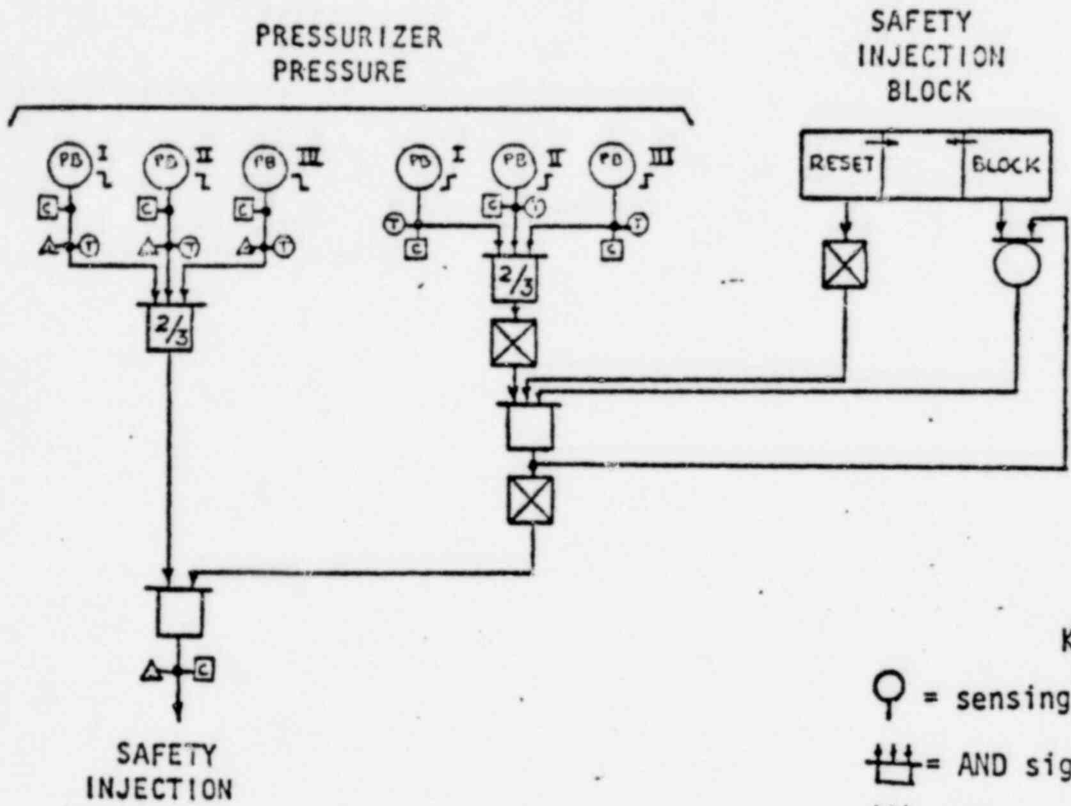


FIGURE 5.3-1 PREVIOUS PBNP PRESSURIZER PRESSURE AND LEVEL SAFETY INJECTION ACTUATION



KEY

= sensing instrument
= AND signal processor
= OR signal processor
= NOT signal processor
= alarm
= test switch
= to computer

FIGURE 5.3-2 CURRENT PBNP PRESSURIZER PRESSURE ONLY SAFETY INJECTION ACTUATION

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5.4 REVIEW OF ENVIRONMENTAL QUALIFICATION OF INCONTAINMENT INSTRUMENTATION

The Point Beach safety-related electrical equipment, located in containment, has been qualified to perform its safety functions under the most severe postulated accident conditions. The equipment involved consists of Containment Fan Cooler Motors, Valve Motor Operators, Pressurizer Pressure and Level Transmitters, Cable, Splices, Penetrations, and Valve Limit Switches. The fan cooler motors, valve motor operators, instrument transmitters, cable and splices were qualified by test by Westinghouse and the Franklin Institute Research Laboratories. The penetrations for Point Beach were pressure tested by Westinghouse and have been qualified for the accident environment by reference to the penetration qualification done by Westinghouse for the Brunswick Nuclear Plant. The valve limit switches which replaced previously unqualified switches were qualified by the vendor (NAMCO).

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5.5 CONCLUSIONS AND RECOMMENDATIONS

Based on the above discussion of plant systems, equipment, and instrumentation, the Task Force has the following conclusions and recommendations:

A. It is the recommendation of the Task Force that the desirability of a remotely operated reactor vessel head vent be studied further based on small break reanalysis, perceived need, and possible future regulatory requirements. It is the conclusion of the Task Force that if a reactor vessel head vent is deemed to be desirable or is imposed as a regulatory requirement, the vessel head should be vented either to the containment atmosphere or to the pressurizer relief tank and not to the pressurizer.

F. It is recommended that the PBNP Staff continue to be informed of the sampling problems encountered at TMI and that the plant operators and chemistry and health physics personnel most knowledgeable concerning equipment layout and sampling points bring to management's attention any condition which they believe requires correction.

C. It is concluded that the present Point Beach design for post-accident hydrogen control in containment is totally acceptable as defined by the current plant license and safety analysis report. However, to further reduce the potential for any radioactive releases during an accident, it is recommended that a preliminary engineering study be performed to determine system design and cost for accommodating a hydrogen recombiner more readily than presently allowed.

D. The Task Force has concluded that full flow testing of the auxiliary feedwater pumps on a monthly basis is neither necessary nor desirable.

E. The Task Force has concluded that, based on testing and operational experience, the natural circulation capability of PBNP has been proven to be completely acceptable. It is further concluded that improvements to the instrumentation available to the operator for identification and monitoring of natural circulation should be made. It is recommended that these improvements include the use of existing hot leg RTDs and more effective utilization of incore thermocouple readouts. In addition, control board information should be provided to aid the operator in identification of void formation with a two-pen recorder for primary coolant system pressure and saturation pressure corresponding to $T_{HOT\ LEG}$ or T_{CORE}.

F. It is recommended that additional work be done by the industry and NRC to verify the adequacy of that portion of the LOCA calculation which models the steam condensing capability of steam generators.

G. It appears that utilization of the steam generator to cool the primary system below 200°F is feasible. The Task Force has no further conclusions or recommendations regarding this topic.

H. The Task Force has concluded that there may be accessibility complications in some areas of the Auxiliary Building as a result of elevated radiation levels following a TMI-type incident. It is recommended that additional reviews be conducted to determine the radiation levels during a post-accident recovery period and to investigate the feasibility of modifications that might either mitigate or preclude such potential complications.

I. A review of instrumentation for actuation and reset of safeguards logic concluded that no design changes are necessary other than the modification of safeguards logic initiated prior to the TMI accident or the modification already completed for low pressurizer pressure safety injection actuation.

J. The Task Force concludes that instrumentation for monitoring of power-operated relief valve positions and flow is adequate.

K. Based on the review of pressurizer level and containment sump level instrumentation, it is concluded that no equipment modification is necessary.

L. The Task Force has considered the need for level instrumentation for the reactor vessel during accident conditions and does not feel that such instrumentation is required.

M. Post-accident, in-containment radiation monitoring devices were considered. The Task Force concludes that such monitoring is not necessary.

SECTION 6

REVIEW OF EMERGENCY PLANNING

6.1 INTRODUCTION

As a result of the events associated with Three Mile Island, a number of questions about the adequacy of emergency plans for nuclear power plants have been raised. In order to assure the adequacy of emergency planning for the Point Beach Nuclear Plant, the current PBNP Emergency Plan was reviewed. Only areas of particular interest are discussed in the following.

6.2 AREAS OF EMERGENCY PLANNING REVIEW

6.2.1 Recognition of Accidents

In general, the single most important apparent operator failure at Three Mi' Island was the failure to recognize that a primary system leak existed. Howeve-, the Task Force was unable to determine any indication that the pot..tial for failing to recognize a leak exists among the operators at PBNP. This conclusion was reached after discussion with former PBNP senior reactor operators now elsewhere in the company, the PBNP Training Supervisor, the Plant Manager, and present PBNP operators. It is believed that PBNP operators will recognize a loss of primary system integrity in a very short time; and PBNP operators will recognize whether natural circulation has been established.

In addition to the above discussions, justification of this belief is based on the following:

A. The general responses from PBNP operators when informed of the TMI sequence of operating events;

B. The virtually immediate recognition by PBNP operators and their excellent performance in response to actual small breaks experienced at the plant, specifically, the pressurizer instrument line failure and the steam generator tube rupture;

C. The excellent performance to date of two PBNP operator retraining groups confronted with simulator testing of responses to a number of situations similar to the events of Three Mile Island;

D. The events of Three Mile Island have been so strongly impressed on operators and other plant personnel that it is unlikely that any small break loss of integrity could continue undetermined for any appreciable period of time; and

E. At PBNP, there are three operators in the control room at all times, including one senior reactor operator. Furthermore, the combined control room at PBNP affords an extra crew at the unaffected unit available to provide unbiased and objective consultation and review without the pressure of immediate responsibility.

The competence of PBNP operators is largely brought about by two conditions. The first is the presence of a significant number of operators with extensive experience in the operation of PWRs. This experience was acquired in the Navy nuclear power program, during the PBNP startup, or as a part of many years of cumulative operating experience. The second is the application of the PBNP training philosophy which stresses competent operator response on a logical basis as opposed to an automatic response to a preconceived set of conditions. As a consequence of these conditions, it is recommended that:

A. PBNP training continue to stress a logical response to all operating conditions. Automatic non-thinking response should continue to be avoided. Book training is most susceptible to the latter, by virtue of practical limitations on the number of scenarios considered. Simulator training has the advantage of providing hundreds of scenarios with minimum duplication. On the other hand, both book and simulator training assume calculated plant response which may or may not be completely accurate. Again, the logical approach is ıı oeı at've.

B. The PBNP training program should incorporate increased emphasis on the importance of incore thermocouples and the need to carefully monitor saturation temperatures.

C. The PBNP Training Supervisor should compare the performance of operators relative to experience. If any significant trends can be identified, measures should be taken to improve the performance of the lower ranking group in order that the present overall level of competence be maintained and improved in the future

6.2.2 NRC Notification

Initial activation of the PBNP Emergency Plan does not await the development of offsite dose observations. Rather, the activation conditions are as prompt as possible and are stated as either of the following conditions:

A. The occurrence of a LOCA that would result in initiation of safety injection with a subsequent potential release of radioactivity; or

B. The occurrence of an incident which causes radiation dose rates in general yard areas of 100 mRem/hr or greater

Notification of NRC and other responding agencies is accomplished with the initial activation of the PBNP Emergency Plan. Since the Plan can be triggered by either the observation of the occurrence of an event or by the observation of the results of an event, no further improvement is possible. The recommendation of offsite evacuation is then based on certain determinations at the site boundary. This is believed to be an optimum scheme.

It is recommended that the present scheme be retained. The Plan should be further reviewed to assure the appropriateness of the order of notification, particularly to determine whether the NRC notification should be moved elsewhere in the procedures. Presently, the Coordinator notifies the NRC.

6.2.3 Other Agency Notifications

Other agencies notified include:

A. The U. S. Department of Energy Radiological Assistance Team

B. Manitowoc County Sheriff

C. Wisconsin State Patrol

D. Wisconsin Department of Health and Social Services, Section of Radiation Protection

E. U. S. Coast Guard

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Implicit in notification of the County Sheriff is notification of the local civil defense office, since the Sheriff constitutes the primary communication center for county civil defense. In some Wisconsin counties, there have been complaints that local directors never receive notification during drills. It is recommended that the Manitowoc County Sheriff be urged to take this step.

It is recommended that the Emergency Plan require notification of both the State of Wisconsin, Division of Emergency Government (DEG), and the Department of Health and Social Services, Section of Radiation Protection. The Emergency Plan itself currently lists the DEG as an alternate. It is recommended that the next revision of the Plan formally require notification of both agencies.

6.2.4 News Media and Government Agency Involvement During and Following an Accident

Except, of course, for the agencies directly responding as addressed above, no current plans exist for interfacing with other government agencies or with the news media. The State of Wisconsin has a good emergency plan which is currently being further upgraded in the process of obtaining NRC concurrence. Furthermore, past and present Governors in Wisconsin have given significant cooperation to emergency agencies and services as evidenced by the annual Governor's Disaster Preparedness Conference. Accordingly, it is believed that, in the event of a nuclear emergency, either the Governor or the DEG would exercise appropriate control and direction of State agencies.

The following steps are recommended:

A. Determine whether existing plans are appropriate for communicating with the Governor;

B. Determine whether policy should be developed for handling communications with government agencies, particularly NRC;

C. Determine whether development of a procedure and assignment of responsibilities for communicating with news media is appropriate; and

D. Determine whether existing plans for establishing communications between the Executive Vice President and PBNP are required.

The Task Force does not recommend any additional provisions for parking, telephones, shelter, food or sanitary facilities for news media or government agencies.

6.2.5 Environmental and Public Monitoring During and Following an Accident

With respect to post-accident monitoring outside the plant, a number of portable survey devices are provided at PBNP, including a gasoline powered air sampler and a simple single channel unit for the analysis of radioiodine on charcoal cartridges. About fifteen thermoluminescent dosimeters (TLDs) are in place in the plant environs as part of the routine radiological environmental monitoring program. These can be used to provide offsite dose information in the event of an accident. An extremely sensitive monitoring instrument (an HPI ion chamber) is available at the plant and is capable of monitoring radiation at background levels. Provisions should be made in the PBNP Emergency Plan for assuring that this instrument is transferred to the Site Boundary Control Center in the event of any evacuation alarm. It may also be appropriate to further review the adequacy of other portable emergency instrumentation and the numbers thereof.

It is apparent from the events at Three Mile Island that whole body counts of offsite residents may be in order if any offsite dose consequences are observed. This need not necessarily be arranged in advance nor addressed in the Emergency Plan.

6.2.6 Adequacy of State Plans and Interface of State and Utility

The Wisconsin Electric Nuclear Projects Office maintains liaison with both the State of Wisconsin Division of Emergency Government (DEG) and the Department of Health and Social Services, Section of Radiation Protection. The State of Wisconsin has an adequate arrangement for establishing communication, responsibilities, and authorities for various state agencies. The State began working toward NRC concurrence well before the Three Mile Island accident and increased the priority of the task after that accident. Final NRC concurrence is currently expected late summer 1979.

In drills, the DEG only notifies the Section of Radiation Protection. In an actual emergency, it would also notify the area direction (of Emergency Government) and the Governor's office.

As noted above, the State Emergency Plan provides the communications, responsibilities, authorities, and the principles for coping with an emergency. Evacuation plans, however, are the responsibility of the County Office of Civil Defense. In short, the County must accept the broad guidance of the State Plan and add its own details. The DEG is willing to render assistance in preparing local plans whenever so requested. It has been evident from recent events that civil defense and other local agencies are inadequately involved in drills and planning efforts. Wisconsin Electric is currently working to improve the interface between PBNP and various local agencies. It is recommended that these efforts be continued.

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6.3 CONCLUSIONS AND RECOMMENDATIONS

The Task Force considers that the existing PBNP Emergency Plan is adequate to assure the health and safety of the public and recommends only minor improvements. The following l'.t present the conclusions and recommendations regarding emergency planning.

A. It is recommended that operator training at PBNP continue to stress a logical response to all operating conditions. Such training promotes prompt recognition of those accident situations which require initiation of the PBNP Emergency Plan.

B. It is recommended that the PBNP Training Supervisor compare the performance of operators relative to experience. If any significant trends can be demonstrated, measures should be taken to improve the performance of the lower ranking group in order that the present overall level of competence be maintained and improved in the future.

D. It is recommended that the present criteria for activation of the PBNP Emergency Plan be retained; however, the appropriateness of the order of notification specified by the plan should be reviewed.

D. It is recommended that the Emergency Plan require notification of both the State of Wisconsin Division of Emergency Government and the Section of Radiation Protection.

E. Attention is directed to four Task Force recommendations regarding news media and government agency involvement and a fifth which considers facilities as presented in Section 6.2.4.

F. Provisions should be made in the PBNP Emergency Plan for assuring that the HPI ion chamber is transferred to the Site Boundary Control Center in the event of an accident having potential off-site consequences. Further review of the adequacy of other portable instrumentation may also be needed.

G. It is recommended that current efforts to improve the interface between PBNP and various local agencies, such as the County Office of Civil Defense, be continued.

SECTION 7

CONTINUED POINT BEACH NUCLEAR PLANT OPERATION

The Three Mile Island Accident Review Task Force was directed to determine for Point Beach Nuclear Plant whether any equipment, design, system, operating procedure, maintenance program, or personnel qualification or training should be modified or changed as a result of the Three Mile Island accident. These activities have included the consideration of whether the Point Beach Nuclear Plant should be shut down as a result of any deficiency or unsafe condition recognized or discovered during these reviews. As discussed in Sections 4, 5 and 6 of this report, the Task Force has reviewed the areas of plant procedures and operation, system and equipment, operator training and emergency planning and preparation. In each of these areas, the Task Force has reached a number of conclusions regarding the continued acceptability of the present Point Beach Nuclear Plant systems and procedures and, in several areas, has recommended changes to systems or procedures to further enhance the safe operation of the plant. It has also suggested areas for continued study and investigation.

It is the overall conclusion of the Task Force that the Point Beach Nuclear Plant has been, and will continue to be, operated in a safe manner which complies in all respects with the provisions of its operating licenses and the regulations of the Nuclear Regulatory Commission. The Task Force further concludes that, in light of our knowledge of the TMI Accident and those reviews identified in this report, continued operation of the Point Beach Nuclear Plant can be conducted without undue risk to the public health and safety, or to the health and safety of the employees who are charged with its safe operation. Therefore, shutdown of the Point Beach Nuclear Plant is not necessary or warranted.

APPENDIX A

NATURAL CIRCULATION TEST

May 25, 1979

Mr. Glenn A. Reed

NATURAL CIRCULATION TEST

Background and Conclusion

During the May 12, 1979, shutdown to convert the safety injection logic to two-thirds low pressure, a natural circulation test was done. The plant characteristics were determined and a method of verifying the existence of natural circulation was investigated. Two conclusions can be drawn.

1. The as-built plant has better natural circulation characteristics than the calculations of the designers would indicate.

2. Either incore thermocouples or loop RTD's can be used to indicate natural circulation.

The Test

The Unit 2 shutdown was started at 0240 hours and the unit was off line at 0630 hours. Both reactor coolant pumps were tripped at 0705 hours and the flow coastdown characteristics measured. Figure 1 shows the coastdown times. During this time 15 incore thermocouples were trended as was a cold and a hot leg RTD. The locations of the thermocouples are shown on Figure 2.

It should be noted that the thermocouples were positioned over fuel that was in its first, second, third and fourth cycle of burnup. This cycle burnup was less than one effective full power month (850 MWD/MTU). All thermocouples responded properly. Since the loop hot leg RTD's are not connected to any readout device, the "B" cold leg RTD was disconnected and the hot leg connected to the R/I converter. A plot of the temperatures is shown in Figure 3.

The test was started from zero power. In this condition, the natural heat losses caused a slight primary system cooldown. Power was then increased in steps until a maximum power of about 4% was achieved. Some boric acid (about five gallons) was injected into the reactor coolant system and the reactivity computer monitored. When the acid passed through the core flux dropped off quite rapidly and then recovered until the slug of coolant with the higher boron concentration went completely through the loops back to the core. At that time flux again dropped off quickly. This slug was monitored

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for at least three loop transients. Then power was reduced and the sequence repeated. Finally power was reduced to the point of adding heat and the sequence repeated. After that a reactor coolant pump was started. Because of the surge of cold water reaching every elevation of the core, the negative temperature coefficient caused a 1.5 dpm startup rate to be sustained for about seven to ten seconds.

Results

As power was increased, ΔT increased as can be seen on Figure 4. This indicates that even immediately after a loss of AC when decay heat is high, natural circulation will be established at PBNP. If the steam generator safety valves control steam pressure at 1100 psia (T_{sat} 556°F), immediately after the trip, the hottest thermocouple would indicate about 608°F (587°F during the test with steam temperature at 535°F). This is still well below the saturation temperature for 1900 psia of 628°F. At very low flux levels, it is difficult to establish the rate of natural circulation since the primary and secondary systems heat losses are greater than the decay heat. The plant tends to cool down.

With nominal reactor coolant flow, the loop transport time is 11.3 seconds.

Power % *	Intermediate Range Amps	Loop Transient Time Minutes	Flow %
4.5	3.0×10^{-5}	3½	5.4
3.0	1.5×10^{-5}	4	4.7
2.3	0.8×10^{-5}	4½	4.1

* Includes 1.5% for decay heat addition.

Figure 5 plots the above data on the curve which the Westinghouse analysis developed.

Better indication of T_{hot}, which is the best indication of natural circulation, can be readily achieved. The present two pen recorder for loop cold leg temperature should be retained for vessel temperature indication for heatup and cooldown considerations. The hot leg RTD's should be connected to R/I and scaled from 450°F to 650°F. This would allow them to be used for reactor coolant system saturation concerns and for nuclear physics measurements. The cold leg RTD's have too wide a range for measurements while the manifold RTD's go off scale at 530°F.

The Honeywell readout device for the incore thermocouples should be replaced. A digital readout which would function for the total thermocouple range would be of more use.

Other Tests

There were two instances in which a unit experienced a loss of outside AC and then established natural circulation. During an ice storm on February 5, 1971, outside power was lost to Unit 1. The wind blew over a lightning arrester in the switchyard on October 13, 1973, causing a loss of AC to Unit 1 and a 20% turbine runback on Unit 2. Unit 1 had been shut down.

In at least one instance the effects of boration with no forced flow were observed. In that case after boron injection, the reduction in flux seen by the excore detectors was observed. This was done on Unit 1 March 10, 1979.

During each startup following a refueling, hot rod drops with no reactor coolant flow is a requirement. During this time the unit is in natural circulation.

There were two previous tests of natural circulation. On May 10, 1975, a test similar to the one being reported was performed on Unit 2 with similar results. Finally, Unit 1 was tested during initial startup and the results reported in the startup report.

The initial test was done on Unit 1 November 22, 1970. The unit had been up to 40% power for a short time so the decay heat was small. Without repeating the calculations, one can conclude that the unit did go into natural circulation. The values for flow derived in the startup report are higher than that which actually existed. It would appear that the values were consistant with the findings on Unit 2.

Summary

This information can be used by the Three Mile Island Task Force in their study of corrective actions that can be taken at PBNF. It is apparent that the basic plant design readily achieves natural circulation. There are some relatively minor equipment additions which will help the operator in analyzing the plant status.

James Zach

J. J. Zach

bjt

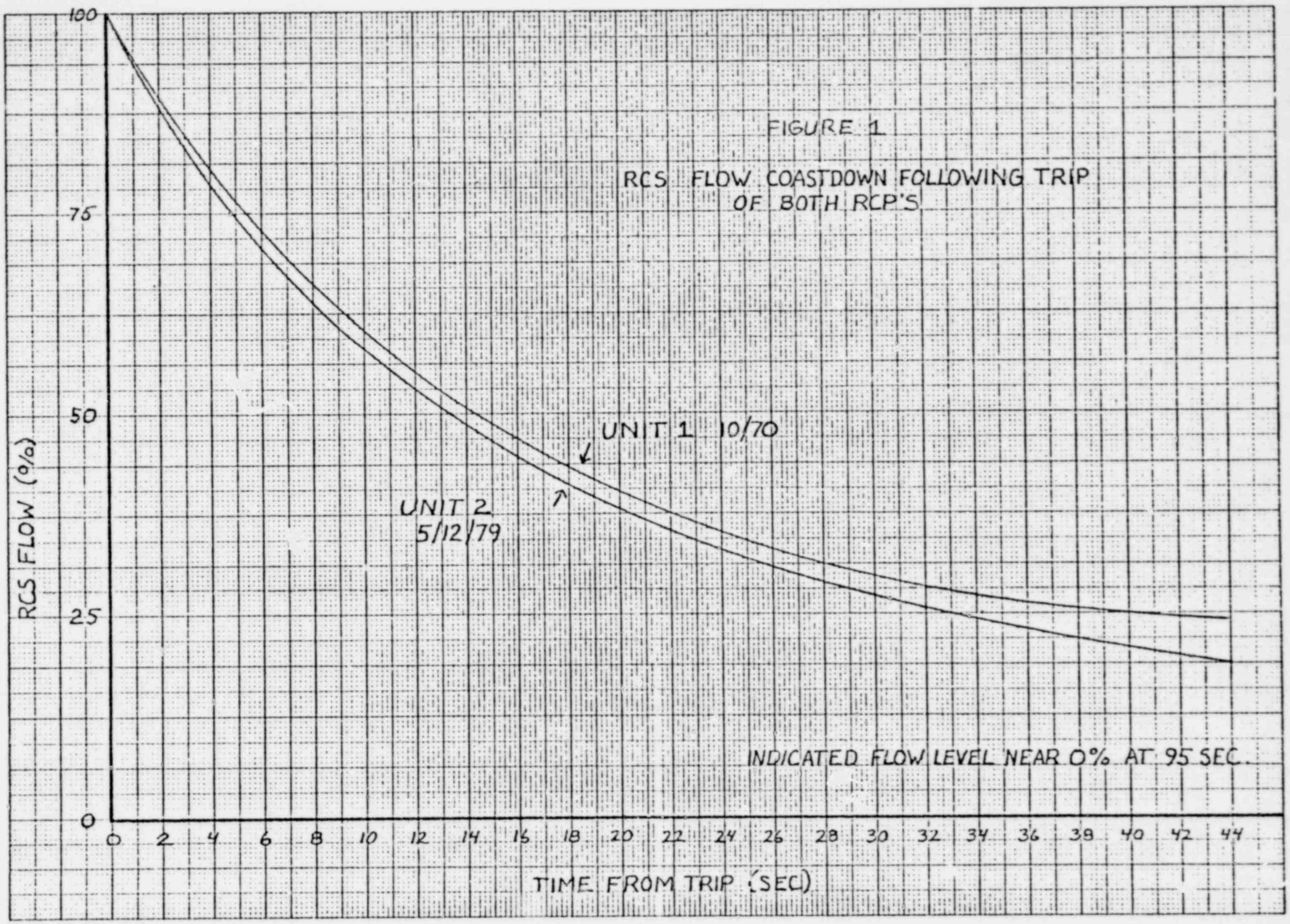
FIGURE 1
RCS FLOW COASTDOWN FOLLOWING TRIP
OF BOTH RCP'S
UNIT 1 10/70
UNIT 2
5/12/79
INDICATED FLOW LEVEL NEAR 0% AT 95 SEC.
RCS FLOW (%)
100
75
50
25
0
0 2 4 6 8 10 12 14 16 18 20 22 24 26 28 30 32 34 36 38 40 42 44
TIME FROM TRIP (SEC)

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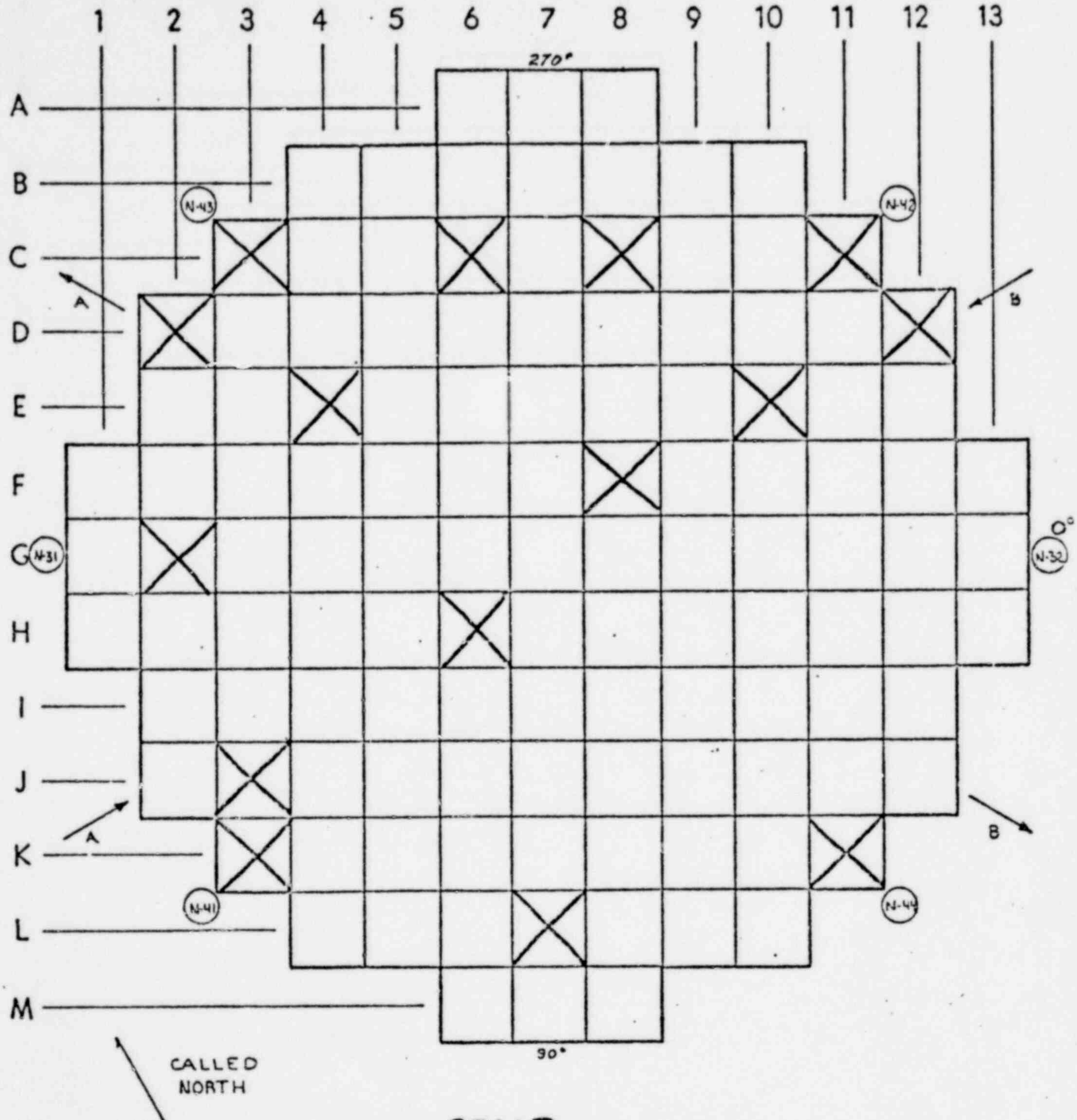
UNIT 2



PBNP

THERMOCOUPLES TRENDED DURING NATURAL CIRCULATION TEST

5/12/79

FIGURE 2

1215 274

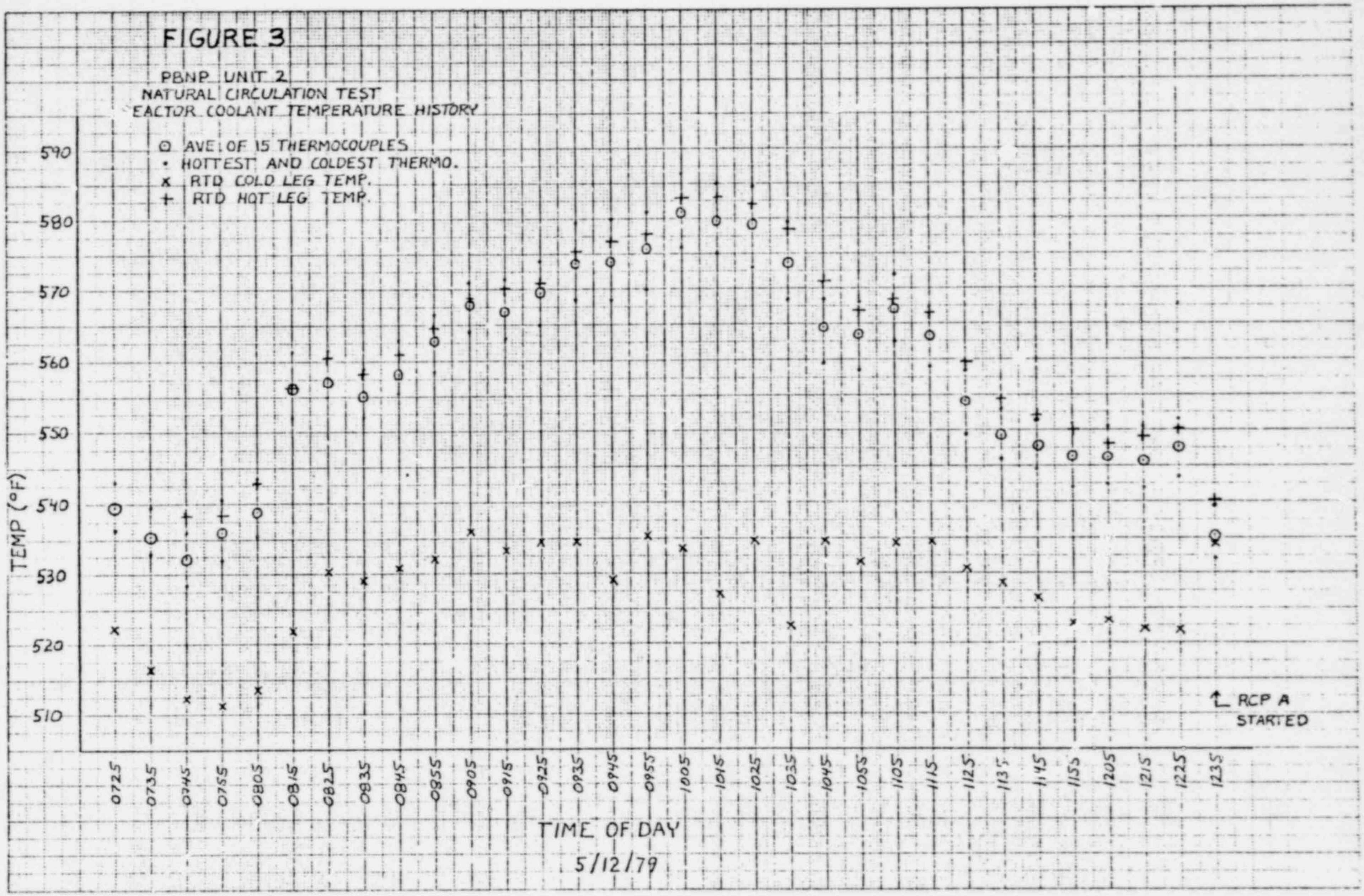


FIGURE 3
PBNP UNIT 2
NATURAL CIRCULATION TEST
EACTOR COOLANT TEMPERATURE HISTORY
⊙ AVE. OF 15 THERMOCOUPLES
• HOTTEST AND COLDEST THERMO.
x RTD COLD LEG TEMP.
+ RTD HOT LEG TEMP.
TEMP (°F)
590
580
570
560
550
540
530
520
510
0725
0735
0745
0755
0805
0815
0825
0835
0845
0855
0905
0915
0925
0935
0945
0955
1005
1015
1025
1035
1045
1055
1105
1115
1125
1135
1145
1155
1205
1215
1225
1235
RCP A STARTED
TIME OF DAY
5/12/79

1215 275

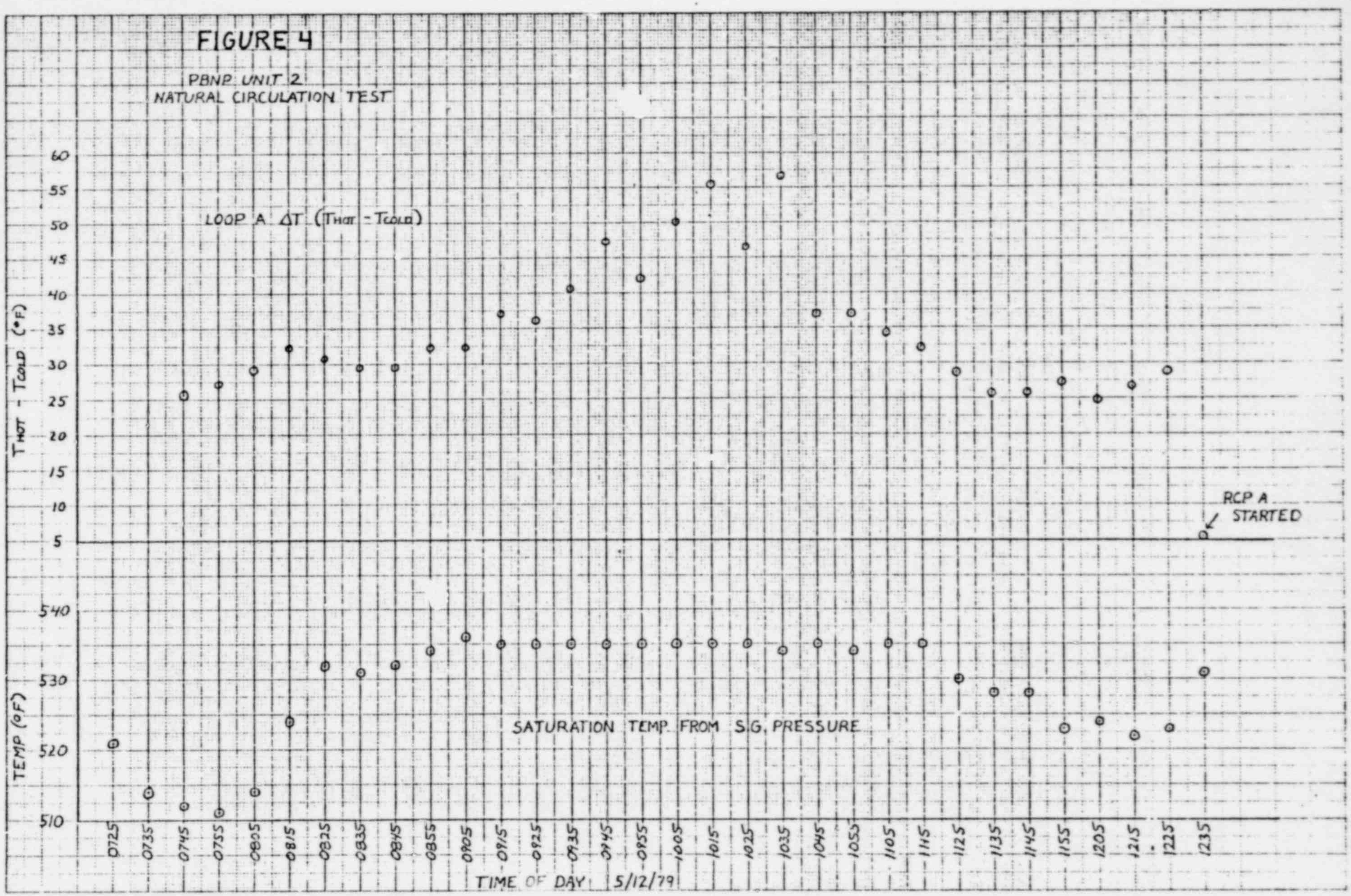


FIGURE 4
PBNP UNIT 2
NATURAL CIRCULATION TEST
LOOP A ΔT (THOT - TCOLD)
THOT - TCOLD (°F)
60
55
50
45
40
35
30
25
20
15
10
5
RCP A STARTED
TEMP (°F)
540
530
520
510
SATURATION TEMP. FROM S.G. PRESSURE
0725
0735
0745
0755
0805
0815
0825
0835
0845
0855
0905
0915
0925
0935
0945
0955
1005
1015
1025
1035
1045
1055
1105
1115
1125
1135
1145
1155
1205
1215
1225
1235
TIME OF DAY 5/12/79

1215 276

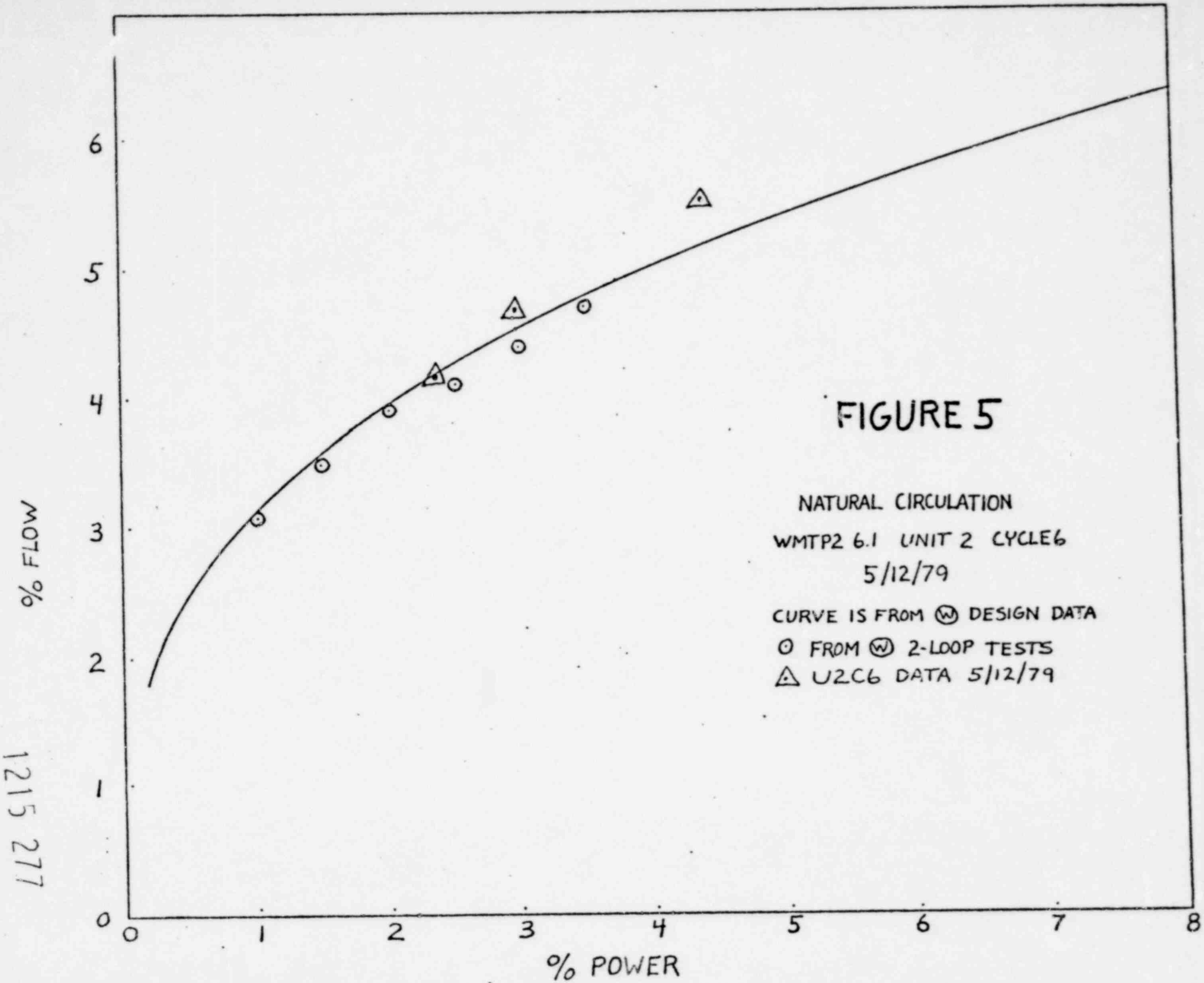


FIGURE 5
NATURAL CIRCULATION
WMTP2 6.1 UNIT 2 CYCLE6
5/12/79
CURVE IS FROM Ⓦ DESIGN DATA
⊙ FROM Ⓦ 2-LOOP TESTS
△ U2C6 DATA 5/12/79
% FLOW
% POWER
0
1
2
3
4
5
6
7
8

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APPENDIX B

ABBREVIATIONS, ACRONYMS AND TERMINOLOGY

AC	Alternating Current
ACRS	Advisory Committee on Reactor Safeguards
AFW	Auxiliary Feedwater
AO	Abnormal Occurrence
Auxiliary	Backup
B&W	Babcock and Wilcox
Bulletin 79-xx	NRC Inspection and Enforcement bulletins
BWST	Borated Water Storage Tank
Cold Leg	Reactor coolant system piping between pump and reactor
Containment	Reactor building
DEG	Division of Emergency Government
d/p	Differential pressure
ECCS	Emergency Core Cooling System
EFW	Emergency Feedwater
EMOV	Electromatic relief valve
EOP	Emergency Operating Procedures
EPRI	Electric Power Research Institute
ESF	Engineered Safety Features
ESGF	Emergency Steam Generator Feedwater
Feedwater	Secondary side cooling water
FFDSAR	Final Facility Description and Safety Analysis Report
gpm	Gallons per minute
HEPA	High Efficiency Particulate Activity
Hot Leg	Reactor coolant system piping between the reactor and steam generator
hp	Horsepower
HPI	High Pressure Injection
HPSI	High Pressure Safety Injection
ID	Inside Diameter
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
Loop	Closed cycle of piping
LPSI	Low Pressure Safety Injection
MWe	Megawatts electric
NaOH	Sodium Hydroxide
NRC	Nuclear Regulatory Commission
NSAC	EPRI National Safety Analysis Center

OP	Normal Operating Procedure
OTSG	Once Through Steam Generator
PBNP	Point Beach Nuclear Plant
PCT	Peak Clad Temperature
ΔP	Pressure differential
PORV	Power Operated Relief Valve
ppm	Part per million
PRT	Pressurizer Relief Tank
P_{SAT}	Saturation pressure
psig	Pounds per square inch gage
psia	Pounds per square inch absolute
RCDT	Reactor Coolant Drain Tank
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RTD	Resistance Temperature Detector
Secondary side	The steam generator, turbine and steam condensing side of a nuclear power plant
Setpoint	An instrument setting at which a specific function will take place
SI	Safety Injection
SOE	Significant Operating Event
SIU	Start-up
T_{COLD}	Temperature of the cold leg
T_{HOT}	Temperature of the hot leg
ΔT	Temperature differential
TLD	Thermoluminescent Dosmeter
TMI	Three Mile Island
Trip	To shutdown, shut off, or secure due to conditions reached
T_{SAT}	Saturation temperature
$Zr-H_2O$	Zirconium-Water

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