6.0 ENGINEERED SAFETY FEATURES
TABLE OF CONTENTS

6.0 ENGINEERED SAFETY FEATURES
TABLE OF CONTENTS

6.0 ENGINEERED SAFETY FEATURES
TABLE OF CONTENTS

6.0 ENGINEERED SAFETY FEATURES
LIST OF TABLES

6.0 ENGINEERED SAFETY FEATURES
LIST OF TABLES

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

Figure

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

Figure

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

Figure

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

Figure

6.0 ENGINEERED SAFETY FEATURES
LIST OF FIGURES

Figure

DRAWINGS CITED IN THIS CHAPTER*

*The listed drawings are included as "General References' only; i.e., refer to the drawings to obtain additional detail or to obtain background information. These drawings are not part of the UFSAR. They are controlled by the Controlled Documents Program.

DRAWING*	SUBJECT
M-6	General Arrangement, Reactor Floor Plans
M-7	General Arrangement, Sections "A-A" and "B-B"
M-8	General Arrangement, Sections "C-C" and "D-D"
M-25	Diagram of Pressure Suppression Piping Unit 2
M-27	Diagram of Core Spray Piping Unit 2
M-29	Diagram of Low Pressure Coolant Injection Piping Unit 2
M-49	Diagram of Standby Gas Treatment
M-5 1	Diagram of High Pressure Coolant Injection Piping Unit 2
M-273-1	Diagram of Control Room and Office Air Conditioning
M-273-2	Diagram of Control Room Kitchen and Locker Room Ventilation System
M-345	Diagram of Main Steam Piping Unit 3
M-356	Diagram of Pressure Suppression Piping Unit 3
M-358	Diagram of Core Spray Piping Unit 3
M-360	Diagram of Low Pressure Coolant Injection Piping Unit 3
M-374	Diagram of High Pressure Coolant Injection Piping Unit 3
M-706	Diagram of Containment Atmosphere Monitor System
M-707	Diagram of Atmospheric Containment Atmosphere Dilution System
M-3121	Piping and Instrumentation Diagram, Control Room HVAC

6.0 ENGINEERED SAFETY FEATURES

This Chapter is organized as follows:

A. Section 6.0 - Identification of engineered safety features;

B. Section 6.1 - Engineered safety feature materials;

C. Section 6.2 - Containment systems;

D. Section 6.3 - Emergency core cooling systems;

E. Section 6.4 - Habitability systems;

F. Section 6.5 - Fission product removal and control systems; and

G. Section 6.6 - Inservice inspection of Class 2 and 3 components.

6.0 Identification of Engineered Safety Features

Section 6.0 is the complete listing of engineered safety feature (ESF) systems, structures, and components. Discussion of a system, structure, or component elsewhere in Chapter 6 does not imply classification as an engineered safety feature. Conversely, systems listed in Section 6.0 but not described elsewhere in Chapter 6 are classified as ESFs, even though the detailed discussion of the system, structure, or component is in another UFSAR chapter.

This section describes the functional requirements and performance characteristics of the ESFs, which have been provided in addition to those safety features included in the design of the reactor, reactor coolant system, reactor control systems, and other instrumentation or process systems described elsewhere in this report. These ESFs are included in the plant for the purpose of reducing the consequences of postulated accidents. The following ESFs have been provided:

A. Containment systems;

B. Emergency core cooling systems;

C. Standby coolant supply system;

D. Main steam line flow restrictors;

E. Control rod velocity limiter;

F. Control rod housing support;

G. Standby liquid control system;

H. Containment atmospheric control system;

I. Reactor protection system; and

J. Isolation condenser.

6.0.1 Containment Systems

The containment systems consist of the primary containment system and the secondary containment system. The performance objectives of the primary containment system are to provide a barrier which, in the event of a loss-of-coolant accident (LOCA), will control the release of fission products to the secondary containment and to rapidly reduce the pressure in the containment resulting from a LOCA. The performance objectives of the secondary containment system are to minimize ground-level release of airborne radioactive materials and to provide for controlled, elevated release of the reactor building atmosphere under accident conditions through the use of the standby gas treatment system (SBGTS). The containment systems are described in Section 6.2. Section 15.6 discusses the LOCA.

The containment isolation system provides protection against the consequences of an accident involving the release of radioactive materials from the reactor coolant pressure boundary by automatically isolating fluid lines which penetrate the containment wall. Sections 6.2.4 and 7.3.2 contain a description of the primary containment isolation system. Section 6.2.3 describes the secondary containment system.

The SBGTS removes radioactive contamination from the air in the secondary containment using a high efficiency particulate air (HEPA) and an activated charcoal filter system. The air is then discharged to the environment through the 310-foot chimney. The SBGTS can also be manually aligned to treat the air inside the primary containment. The SBGTS is described in Section 6.5.

6.0.2 Emergency Core Cooling System

The emergency core cooling system (ECCS) is automatically placed in operation whenever a loss-of-coolant condition is detected. The subsystems contained in the ECCS are the core spray, low pressure coolant injection (LPCI)/containment cooling, high pressure coolant injection (HPCI), and automatic depressurization (ADS) systems. The core spray and LPCI systems are designed for low-pressure operation, whereas the HPCI and ADS systems are designed for high-pressure operation. The containment cooling system is a separate function of the ECCS and is designed to remove heat from the containment, reduce the containment pressure and restore suppression pool temperature following a LOCA. The containment cooling system is described in Section 6.2.2, the ECCS is described in Section 6.3, and the LOCA is discussed in Section 15.6.

6.0.3 Standby Coolant Supply System

The standby coolant supply system is a crosstie between the station service water and the condenser hotwell of each unit. It supplies water to maintain feedwater flow to the reactor in the event the water is needed for core flooding or containment flooding following a postulated LOCA. The crosstie is supplied with double valves to minimize leakage of river water to the condenser. The system is manually operated from the control room. The standby coolant supply system is described in Section 9.2.8. The LOCA is discussed in Section 15.6.

6.0.4 Main Steam Line Flow Restrictors

The main steam line flow restrictor is a simple venturi, welded into each main steam line, for the purpose of limiting the steam discharge through a break in the steam line. The main steam line break accident is described in Section 15.6. A description of the main steam line flow restrictors is provided in Section 5.4.4.

6.0.5 Control Rod Velocity Limiter

The control rod velocity limiter consists of two conical elements which restrict the downward fall of the control rod yet do not retard the upward motion of the control rod during scram. These conical elements have no moving parts and are attached to the control rod. A description of the control rod velocity limiter is provided in Section 4.6. The control rod drop accident is analyzed in Section 15.4.9.

6.0.6 Control Rod Housing Support

The control rod housing support is a gridwork located immediately below the control rod housings. Its purpose is to prevent control rod ejection should the control rod housing fail. A description of the control rod housing support is provided in Section 4.6.

6.0.7 Standby Liquid Control System

The standby liquid control (SBLC) system fulfills two performance objectives. First, it provides an additional and independent means of reactivity control and is capable of making and holding the reactor core subcritical from any hot standby or hot operating condition. The liquid control is a liquid boron solution which can be injected into the reactor vessel at pressures above the vessel design pressure at a constant flowrate. A description of the standby liquid control system is provided in Section 9.3.5. Failure to scram is discussed in Section 15.8.

Second, in the event of a design basis LOCA, the contents of the SBLC system tanks are injected into the suppression pool to maintain the pH of the pool at a value greater than 7. This ensures that the particular iodine deposited into the pool during a DBA LOCA does not re-evolve and become airborne as elemental iodine. This role of the SBLC system is described in UFSAR 15.6.5.5.

6.0.8 Containment Atmospheric Control

The primary containment atmospheric control system consists of the vent, purge, and inerting system; the pumpback system, the nitrogen containment atmosphere dilution (NCAD) system; and the containment atmosphere monitoring system. The air dilution capability of the atmospheric containment atmosphere dilution (ACAD) system has been permanently disabled. The ACAD pressure bleed subsystem has been disabled and the piping has been cut and capped. The primary means of containment combustible gas control is the inerted containment. The pumpback system is not used for post-accident consequence mitigation and is not an ESF. Those portions of the CAM system and the vent, purge, and inerting system which are utilized for post-accident consequence mitigation are ESFs. The atmospheric control systems are described in Section 6.2.5, and the LOCA is analyzed in Section 15.6.

6.0.9 Reactor Protection System

The reactor protection system (RPS) monitors reactor operation and initiates a reactor trip upon detection of an unsafe condition that might cause damage to the reactor fuel or result in the release of radioactive materials to the environment. It is designed to function following any design basis accident described in Chapter 15. The RPS is described in Section 7.2.

6.0.10 Isolation Condenser

The isolation condenser provides cooling for the reactor core when the reactor becomes isolated from the main condenser upon closure of the main steam isolation valves (MSIVs). Closure of the MSIVs can occur following a loss of offsite power, as described in Section 15.2. The isolation condenser is backed up by the HPCI system. It is described in Section 5.4.6.

6.1 ENGINEERED SAFETY FEATURE MATERIALS

Materials used in the Dresden engineered safety feature (ESF) systems are required to withstand the environmental conditions encountered during normal operation and subsequent to any postulated accident requiring their operation. The selection of these materials is based on an engineering review and evaluation for compatibility with other materials to preclude interactions that could potentially impair the operation of the ESF systems.

Section 6.2.1.2.1.1 discusses materials used in the drywell expansion gap between the steel drywell liner and the concrete walls.

6.1.1 Metallic Materials

6.1.1.1 Materials Selection and Fabrication

Engineered safety feature systems and components have been evaluated for adequacy of the materials of fabrication. Since original plant design and construction, several codes and standards have been revised to incorporate the results of additional research. Revised codes affecting material selection and fabrication are:

A. Fracture toughness,

B. Quality group classification,

C. Code stress limits,

D. Radiography requirements, and

E. Fatigue analysis of piping systems.

Changes in the areas of quality group classification, code stress limits, and fatigue analysis of piping systems were determined by the NRC to have little impact on the safety of ESF systems. However, since a radical change in the fracture toughness test requirements occurred in 1972, and since radiography requirements compared to available documentation of the inspections actually performed on certain components indicated a possible discrepancy, a reevaluation of associated components was performed. The results of this reevaluation are discussed below and tabulated in Table 6.1-1. Refer also to SEP TOPIC III-1: Classification of Structures, Components, and Systems (Seismic and Quality) for a discussion of component radiography inspection requirements.

The original specifications indicate that the low pressure coolant injection (LPCI) pump casings, high pressure coolant injection (HPCI) pump casings, and core spray pump casings were built to ASME Section III, Class C. The 1965 edition of the code requires impact testing. Also, according to Table ND-2311-1 of the code, A216, Grade WCB would be exempt from impact testing if the material was quenched and tempered (ASME Section III allows heat treating but does not require it). The design temperature range of these pumps is 40°F to 165°F, with normal operating temperature around 95°F. Brittle fracture is not a problem in this moderate temperature range.

The original specification indicates that the LPCI heat exchangers (shell side) were built to ASME Section III, Class C. The 1965 edition of the code requires impact testing. Material specification A212 has been discontinued and replaced by A515, Grade 70. Fracture toughness at the minimum heat exchanger service temperature of 51°F has been analyzed and shown to be adequate. Refer to Section 6.2.2.3.3 for additional details of this evaluation.

The HPCI drain and condensate line piping, fittings, and valves have 5/8-inch or less nominal wall thickness and are exempt from impact testing. The steam piping is over 6 inches in diameter and has a 5/8-inch or less nominal wall thickness with the lowest operating temperature exceeding 150°F. This further exempts this system from impact testing according to ASME Section III, NC 2311a9.

Note that ASME Section III, 1965 edition, provided minimum construction requirements for vessels used in nuclear power plants. It classified pressure vessels as A, B, or C. Class A vessels are equivalent to Class 1 vessels of the current code. Class B is concerned with containment vessels, and Class C is concerned with vessels used in a nuclear power system not covered under Classes A or B. System classification is addressed in the Dresden Station Inservice Inspection (ISI) Plan. As noted in the plan, piping, pumps and valves were built primarily to the rules of USAS B31.1.1.0-1967, Power Piping. Consequently, the Dresden Station ISI Program does not contain any ASME Section III, Code Class 1, 2, or 3 systems. The ISI Program system classifications are based on Regulatory Guide 1.26, Revision 3, and were developed for the sole purpose of assigning appropriate ISI requirements. The ISI Program is discussed further in Sections 5.2 and 6.6.

The LPCI and core spray pumps for Dresden are Class 2 components, as described in Regulatory Guide 1.26 under Group B quality standards. The code of construction and current classification of the pumps were verified by GE.

The DGCW and CCSW systems contain cast iron valves. Additionally, the CCSW pump casings are made of cast iron. Because the use of cast iron in safety-related systems was not evaluated at the time of the NRC Systematic Evaluation Program (SEP), cast iron was not addressed in the NRC Safety Evaluations regarding SEP Top III-1. Cast iron has lower ductility and fracture toughness than other materials typically used in safety-related piping systems. Although it is an acceptable material in the USAS B31.1-1967 code, there are no material specifications for cast iron that are acceptable in the 1977 ASME Section III Code, which formed the basis of the evaluation criteria of SEP Topic III-1. To accommodate the lower ductility and fracture toughness, cast iron valve bodies and pump casings in the DGCW and CCSW systems meet the acceptance criteria described in Section 3.9.3.1.3.5.1.

Confirmation that the atmospheric storage tanks meet current compressive stress requirements was requested by the NRC. In response to this request, it was found that the standby liquid control tank was designed and analyzed based on the methodology outlined in API-650 Code specifications. However, in 1982 the tank was requalified per the then current ASME Section III, Subsection ND. It was determined that the standby liquid control tank roof cover, vessel shell, base plate, roof ring, weldment, and U-bolts met the ASME Code requirements current in 1982. The analysis also showed that the actual stresses in these components subjected to specified seismic excitations are well within the ASME Section III allowables at the design temperature of 150°F.

Reflective Metal insulation (mirror type) or nonmetallic insulation (Nukon Blanket, foam glass or closed cell foam plastic) installed on piping inside the containment meets the requirements as defined in Section 5.2.3.2.3, "Compatibility of Construction Materials with External Insulation and Reactor Coolant". Therefore, the potential for stress corrosion cracking due to the presence of leachable chlorides in nonmetallic thermal insulation is not a concern.

6.1.1.2 Composition, Compatibility, and Stability of Containment and Core Spray Coolants

Dresden Station uses high-purity demineralized water in the reactor vessel and for post-accident containment spray and core spray. The torus also contains demineralized water.

All carbon steel surfaces in the torus are painted to prevent corrosion (see Section 6.1.2). Even without protective coatings, the expected corrosion rate for carbon steel, used structurally in air-saturated demineralized water, is less than 10 mils per year. Such a corrosion rate following an accident is of negligible significance.

In the unlikely event that the standby liquid control system were actuated after a loss-of-coolant accident (LOCA), sodium pentaborate solution would be introduced into the reactor vessel. If the vessel were refilled to the elevation of the break, the sodium pentaborate solution in the vessel would spill into the torus.

When sodium pentaborate dissolves in water, it produces a mildly basic solution. The pH of the solution varies with concentration. For the range of concentrations expected, the pH is between 7.4 and 7.8.[1] At the maximum expected sodium pentaborate concentration during recirculation, carbon steel would corrode at a uniform rate of about 11 mils per year, and stainless steel at a rate of less than 0.1 mils per year. Again, these rates are insignificant following an accident. Thus, no additional provisions are required to control corrosion of steel following an accident.

Dresden relies primarily on inerting the containment atmosphere for post-accident hydrogen control. Control of post-accident chemistry to minimize the evolution of hydrogen from aluminum corrosion is therefore not a consideration in the Dresden design. Post-accident iodine control is accomplished through containment integrity, and operation of the standby gas treatment system. Containment spray additives, such as sodium hydroxide, are not used to remove radio-iodines from the containment atmosphere. Therefore, post-accident chemistry control to ensure the retention of iodines in sump water is not required.

Reactor water is sampled and analyzed for conductivity and chloride concentration every 72 hours during normal operation, to ensure that the conductivity and chloride concentration do not exceed 5 μmho/cm and 0.5 ppm, respectively. Water in the condensate storage tank is sampled 3 times a week, to ensure that the conductivity and chloride concentration do not exceed 1 μmho/cm and 0.01 ppm, respectively, and that the pH is between 5.6 and 8.6. The torus water is sampled monthly.

The NRC has determined that the use of demineralized water in the reactor vessel, post-accident containment spray, and core spray, in conjunction with the established periodic water sampling programs, provide reasonable assurance that the conductivity, pH, and chloride concentration of the water would be within the normal plant operating limits such that proper water chemistry can be maintained during the recirculation phase following a DBA consistent with the acceptance criteria of Standard Review Plan Section 6.1.1 for boiling water reactors.

6.1.2 Organic Materials

Identified coatings cover approximately 180,500 square feet of the interior of the Dresden containment. Approximately 58,950 square feet of this is in the drywell, and 121,550 square feet is in the torus.

The drywell shell, reactor shield wall, and vessel supports were originally coated with Dupont #67-4-746 Dulux Zinc Chromate Primer. This layer was covered with Carboline Rustbond Primer 6C Modified Vinyl. It was finished with Carboline Polyclad #933-1 Vinyl Copolymer. These two vinyls are described as a polyvinyl chloride. Failure of this type of material is at an exposure of 8.7×10^8 rads.[2] The total integrated dose for coatings within a typical BWR containment ranges from 5×10^6 to 3×10^9 rads, with most surfaces seeing less than 10^7 rads.[3] The normal integrated 40-year dose for Dresden is between 1.5×10^6 to 1.9×10^6 rads;[4] add this to a 1-year post-accident dose of 1.1×10^8 rad[5] and the total dose inside drywell would be 1.11×10^8 rads. It is, therefore, evident that this coating system would not fail due to radiation effects following an accident.

Other components of the drywell, which are coated with different materials, would not fail due to radiation effects following an accident. The concrete surfaces are coated with Carboline 195 Surfacer, a modified epoxy-polyamide, and Carboline Phenoline 368 WG Finish, a modified phenolic. The maximum gamma radiation resistance of an epoxy is approximately 4×10^8 to 9×10^8 rads, while that of phenolic coatings is 4.4×10^9 rads. The structural steel framing and lateral bracing are covered with the above named Dupont primer, an intermediate coating of alkyd enamel, and a finish of Detroit Graphite Red Lead 501 Alkyd Enamel. The grating areas are covered with the Dupont Zinc Chromate and finished with the Alkyd Enamel. The maximum gamma radiation resistance for an Alkyd Enamel is 5.7×10^9 rads. As compared to the values listed in Section 6.1.3, Reference 3, it may be deduced that this system would not fail following an accident.

The design temperature for the Dresden containment is 281°F for a design basis accident (DBA) and 135°F during normal power operation (see Section 6.2.1). The manufacturer's data lists the vinyls' main temperature resistance at approximately 150°F and the phenolics at 200°F – 250°F. This low temperature resistance in the vinyl materials is causing some peeling in the upper level of the drywell. The material has never dropped off, and the peelings are smaller than 1 square inch. Also, pull tests show pulls were greater than 200 pounds, as stated in the ANSI N5.12 report. This problem is controlled by removing the loose coatings, performing the proper surface preparation and touching up the degraded areas with coatings that are DBA qualified to ANSI N101.2, N101.4 and N5.12 requirements. These products shall be evaluated for chemical resistance, decontaminability, radiation tolerance and exposure to DBA conditions. Failure is not expected with these products (except in the immediate area of a line break) as evidenced by DBA test results for these coatings under LOCA conditions. For touch-up work in the torus, coatings that are DBA qualified to ANSI N101.2, N101.4 and N5.12 requirements shall also be used.

Since the ESF fluids are not taken from the sump in the Mark I design, it is unlikely that any peeling of the vinyl paint on drywell surfaces would lead to significant safety problems. The sump at the bottom of the drywell acts as a drain which is valved off during the DBA. The containment and core sprays during a DBA take suction from the bottom of the suppression pool. Any peeling vinyl paint flakes would collect in the bottom of the drywell where they would not interfere with the coolant recirculation during a DBA. Taking into account these features of the Mark I design, there is reasonable assurance that any peeling of the vinyl paints in the DBA environment would not interfere with the operation of the engineered safety features.

The two main safety concerns that the torus internal coating systems must address are as follows:

A. That the coating materials remain adherent and do not fall off in sufficient quantities under DBA conditions so as to adversely affect the operation of engineered safety systems, and

B. That the coating system effectively prevents degradation (e.g., corrosion) of the containment systems themselves under normal operating conditions.

The original coating system applied to the Unit 2 torus in January 1968 was Phenolic 368 manufactured by the Carboline Company. The portion of the coating system below the waterline (immersion phase) failed by gross intercoat delamination early in its lifetime and was replaced with the Carbo Zinc 11 inorganic zinc primer (also manufactured by Carboline). This system failed within 2½ years because of insufficient coating thickness at the time of first application (the zinc was cathodically sacrificed). Subsequently, a new application of Carbo Zinc 11 with adequate thickness was applied in January of 1975. Meanwhile, the vapor phase of the system (above the waterline) aged rather poorly and by 1984 was described as showing 3 to 10% pinpoint rusting throughout. Abrasive blast cleaning and total recoating of the torus internals was performed during the D2R11 outage using a new epoxy coating (the 6548/7107 system manufactured by the Keeler and Long Company was installed). In addition, a "holiday" (sponge) test was performed to detect and fix all pin holes that may have existed in the new coating. The total dry film thickness falls within the coating's qualified thickness range. Thus, the coating is likely to perform as expected of a service level Class I coating system.

The old epoxy/modified phenolic coating remains on most of the vent system components. Although most of the vent system is in the vapor phase of the torus, half of the downcomers have this old coating below the waterline on their interior surfaces.

The original Phenolic 368 coating system was applied to the Unit 3 torus in June of 1968. The vapor phase failed by pinpoint rusting after about 16 years of service.

In the immersion phase, gross failure similar to that at Unit 2 was detected and the Carbo Zinc 11 primer was applied. Again the inorganic zinc was deemed unserviceable after only two 1-year cycles of operation. In May of 1975, five different coating systems were applied (three phenolic and two epoxy) to determine which of the systems would provide the best service when exposed to the actual torus environment. The test results showed that the Plasite 7155H and Carboline 368 systems failed, but the Carbo Zinc 11, Mobil 78 epoxy, and Keeler and Long 7107/7500/7475 epoxy system performed satisfactorily. The Keeler and Long system developed some blisters but these were observed to be associated with the 7475 finish coat only and were probably due to application problems. The test period was approximately 10 years. Subsequently, a total abrasive blast cleaning and recoat was performed during the D3R10 outage.

Additionally, Carbon Zinc 11 SG was used to coat the safety relief valve (SRV) lines and T-quencher frames.

The painting systems, both in the drywell and in the torus, are inspected and repaired as necessary during each refueling outage. Evaluation of coating integrity is conducted in accordance with the requirements of ANSI N101.2-1972, Section 4.5. The chemical, temperature, and radiation resistance of the current coating systems, together with periodic inspection and maintenance, make the possibility of torus strainer clogging due to coating failure after an accident, remote. Refer to Section 6.2.2.3.2 for an analysis of the potential effects of torus water contamination by debris.

Very small amounts of gas are evolved when aromatic organic compounds of the type found in radiation-resistant plastic are irradiated. For example, a phenolic plastic irradiated to a dose of 10^9 rads produced 3 milliliters (STP) of gas per gram of plastic.[2] For the approximately 150 cubic feet of organic coating existing in the containment, approximately 90 cubic feet of gas would be generated for the conservatively estimated DBA dose of 10^8 rads. The gas is mostly hydrogen and carbon dioxide, and less than a tenth of it is volatile organic compounds. The presence of small amounts of organic gases in containment after a DBA would not interfere with the adsorption of organic iodides by the purge charcoal filters.

The amount of hydrogen from this source is small compared to that which could be produced in a DBA from the zirconium-water reaction, from the radiolysis of water, or from the reaction of the zinc in inorganic zinc coatings with high-temperature borate solutions.[6]

6.1.3 References

1. U.S. Borax Industrial Products Catalog, p. 65, n.d., figure titled, "pH Values in the System Na_2O-B_2O_3-H_2O at 25°C."

2. Bolt and Carrol, Radiation Effects on Organic Materials, Academic Press, New York 1963.

3. American National Standards Institute, ANSI N101.2-1972, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities."

4. "Environmental Qualification of Electrical Equipment Dresden Nuclear Power Station Unit 2," Bechtel Power Corporation, November 1, 1980, Volume 3 of 3.

5. Response to IE Bulletin 79-01B Post-LOCA/HELB Radiation Exposure Levels Received by ESF Components for Dresden Nuclear Power Station Units 2 and 3, Bechtel Power Corporation, July 18, 1980.

6. Zittel, H.E, "Post-Accident Hydrogen Generation from Protective Coatings in Power Reactors," Nuclear Technology 17, pp. 143-146, 1973.

Table 6.1-1

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Recirculation System					
Recirculation system piping	Class A	Type 304 stainless steel[5]	No	8e	
Recirculation system valves	Class A	ASTM A351, Gr. CF8M stainless steel	No	8e	
Recirculation system pumps	Class A	Type 304, 316 stainless steel	No	8e	
Emergency Systems					
Isolation Condenser					
Shell side	Class C	ASTM A106, Gr. B carbon steel	No	8a	
Tube side	Class B	Type 304, 316 stainless steel	No	8e	
All stainless steel piping, valves, fittings	Class B	Type 304[6]	No	8e	
All carbon steel piping	Class B	ASTM A106, Gr. B	No	8a	
Fittings and Valves	Class B	carbon steel	No	8a	
Standby Liquid Control System					
Pump casing	Class B	Carbon steel	No	8d	
Tank	Class B	Type 304 stainless steel	No	8e	
Piping	Class B	Type 304 stainless steel	No	8d, e	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification(1)	Material	Impact Test Required?	Reason for Exemption(2)	Remarks
Core Spray System					
Pump casing	Class B	ASTM A216, Gr. WCB carbon steel	Yes		Thickness up to 13/16 in.
All carbon steel piping	Class B	ASTM A106, Gr. B(7)	No	8a	
Valves and fittings	Class B	carbon steel	No	8a	
All stainless steel piping, fittings, valves	Class B	Type 304	No	8a, e	
Spray spargers and spray nozzles	Class B	Type 304 stainless steel	No	8e	
Low Pressure Coolant Injection					
Pump casing	Class B	ASTM A216, Gr. WCB carbon steel	Yes		Thickness up to 13/16 in.
All Stainless steel piping, fittings, valves	Class B	Type 304(9)	No	8e	
All carbon steel piping	Class B	ASTM A106, Gr. B	No	8a	
Valves and fittings	Class B	carbon steel	No	8a	
Containment Cooling Service Water					
Pump Casing	Class C	ASTM A126, Class B	No	8a	
All Carbon steel piping	Class C	ASTM A106, Gr. B	No	8a	
Carbon steel valves and fittings	Class C	carbon steel	No	8a	
Cast iron valves	Class C	ASTM A126, Class B	No	8a	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification(1)	Material	Impact Test Required?	Reason for Exemption(2)	Remarks
Heat exchangers:					
tube side	Class B	70/30 CuNi(8)	No	8f	
shell side	Class C	ASTM A212, Gr. B carbon steel	Yes		Portions have 1-in. thickness
High Pressure Coolant Injection					
Pump casing	Class B	ASTM A216, Gr. WCB carbon steel	Yes		Thickness up to 1 1/2 in.
Piping	Class B	ASTM A106, Gr. B carbon steel	No	(8a, d)(3)	Impact test on all piping with nominal pipe diameter greater than 6 in.
Fittings, and valves	Class B	carbon steel	No	8a	
Spargers (feedwater spargers used)	Class B	Austenitic stainless steel	No	8e	
Standby Coolant Supply System (condenser hotwell to service water line)					
Pipings, fittings, and valves	Not safety-related				Deleted

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Standby Gas Treatment System					
Pipings	Class B	ASTM A106, Gr. B, ASTM A211	No	8a	
fittings, and valves	Class B	Carbon steel,	No	8a	
Primary Containment					
Safety valves	Class A	Carbon steel	No	8d	
Relief valves	Class A	Carbon steel	No	8d	
Containment Penetrations					
Hydraulic lines to the control rod drives	Class B	Stainless steel	No	8d	
Valves	Class B		No	8d	
Containment Isolation Valves Not Listed with Major System	Class A		No	8d	
Control Rod Drive Housing	Class A		No	8d	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification(1)	Material	Impact Test Required?	Reason for Exemption(2)	Remarks
Control Rod Drive System					
Velocity limiter	Class B	Stainless steel casting	No	8d	
Guide tubes	Class B	Type 304 stainless steel	No	8e	
Spent Fuel Storage Facilities					
Spent fuel pool	Class C	Stainless steel lining (3/16-in. thick)	No	8a	
Reactor Vessel Head Cooling System					
Piping, fittings, and valves	Class C	Stainless steel(10)	No	8d, e	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[1]	Material	Impact Test Required?	Reason for Exemption[2]	Remarks
Condensate Feedwater System					
Piping from reactor vessel to outermost containment isolation valve	Class A	ASTM A106, Gr. B carbon steel	No	LST $\geq$ 150F	Thickness varies from 1.000-1.375 in.
Valves and fittings	Class A	Carbon steel	No	LST $\geq$ 150F	
Main Steam System					
Piping	Class A	ASTM A106, Gr. B	No	LST $\geq$ 150F	Thickness 1.031 in.
Valves and fittings	Class A	Carbon steel	No	LST $\geq$ 150F	
Condensate Storage Tank	Class C	Aluminum	No	8f	
Compressed Air System					
Piping, fittings, and valves	Class D		No	8d	

Table 6.1-1 (Continued)

FRACTURE TOUGHNESS REQUIREMENTS

Structures, Systems, and Components	Quality Group Classification[(1)]	Material	Impact Test Required?	Reason for Exemption[(2)]	Remarks
Standby Diesel-Generator System					
Service water piping	Class C	ASTM A106, Gr. B	No	8a	
Carbon steel valves and fittings	Class C	Carbon steel	No	8a	
Cast iron valves	Class C	ASTM A126, Class B	No	8a	
Fuel oil piping	Class C	ASTM A53, Gr. B	No	8a	
Valves and fittings	Class C	Carbon steel	No	8a	

Notes:

1. The quality group classification given here is the Regulatory Guide 1.26 classification to determine fracture toughness testing requirements and should not be confused with safety classification. Refer to Section 3.2 for a discussion of safety classifications.
2. Refer to Tables A4-4 — A4-6 of Appendix A in Franklin Research Center report on quality group classification of components and systems for explanation of exemptions.
3. Applies to drain and condensate piping.
4. For piping 2" and under, ASTM A335 Grade P11 or P22 may be substituted for ASTM A106 Grade B material for the same schedule. For fittings and valves 2" and under, ASTM A182 Grade F11 or F22 may be substituted for ASTM A105 for the same rating. Substitutions are allowed up to a maximum temperature of 450°F (operating or design) and apply to non-safety related piping and fittings only. No generic substitution of safety related piping/fittings is allowed.
5. Piping replacement on Unit 3 changed the piping material to type 316 stainless steel.
6. A portion of the Unit 3 isolation condenser return line was replaced with type 316 stainless steel.
7. A portion of the piping from outboard valves 2-1402-24A/B to the reactor vessel safe end (Unit 2) was replaced with carbon steel SA333, grade 6 under M12-2-75-39.
8. Some of the CCHX tubes have been replaced by A1-6XN alloy tubes.
9. A portion of the LPCI discharge, inboard from the outboard isolation valve, was replaced with type 316 (special chemistry) stainless steel.
10. A portion of the system is fabricated from A106, grade B carbon steel.
11. Material type A106, grade B is the preferred material with A53, grade B as an acceptable substitute when A106 is not available.

6.2 CONTAINMENT SYSTEMS

This section presents the design considerations for the containment. The combination of these design aspects provides a conservative basis for overall containment integrity.

Dresden Station employs multi-barrier pressure suppression containment design that applies containment-in-depth principles. The primary containment system for each unit is located within a common secondary containment.

The Dresden primary containment system, depicted in Figure 6.2-1, is commercially known as a General Electric Mark I design. It includes a drywell, which encloses the reactor pressure vessel and the reactor recirculation system; a pressure suppression chamber (or wetwell); and a vent system connecting the drywell to the pressure suppression chamber.

Any leakage from the primary containment system is to the secondary containment, which consists of the reactor building, standby gas treatment system, drywell purge ductwork, main steam isolation valve room, high pressure coolant injection room, and chimney. The reactor building encloses both reactors and their respective primary containment systems. The secondary containment is addressed in Section 6.2.3.

The equipment and evaluation presented in this section are applicable to either unit.

6.2.1 Primary Containment Functional Design

The primary containment system consists of a drywell; a pressure suppression chamber which is partially filled with water; a vent system connecting the drywell and the suppression chamber water pool; isolation valves; heating, ventilating, and cooling systems; and other service equipment. The drywell is a steel pressure vessel which houses the reactor vessel, the reactor coolant recirculation system, and other branch connections of the reactor primary system. The pressure suppression chamber is an approximately toroidal steel pressure vessel encircling the base of drywell. Due to its shape the suppression chamber is commonly called the torus. The vent system from the drywell terminates below the suppression chamber water level. Refer to Figures 6.2-1 through 6.2-5 for cutaway views of the Mark I primary containment.

In the event of a nuclear steam supply system (NSSS) piping failure within the drywell, reactor water and/or steam would be released into the drywell. The resulting increased drywell pressure would force a mixture of noncondensible gases, steam, and water through the connecting vent lines into the pool of water in the suppression chamber. The steam would condense rapidly and completely in the suppression pool, resulting in suppression of the pressure increase in the drywell. Noncondensible gases transferred to the suppression chamber would pressurize the chamber and would eventually be vented back to the drywell to equalize the pressure between the two vessels. Cooling systems would remove heat from the drywell and from the water and gases in the suppression chamber to provide continuous cooling of the primary containment under accident conditions. The containment cooling system is discussed in Section 6.2.2. During this period, appropriate isolation valves would close to ensure containment of radioactive materials which might otherwise be released. The primary containment isolation system is discussed in Section 6.2.4.

6.2.1.1 Design Bases

The principal design criteria for the containment systems are presented in Section 1.2.1.3. The performance objectives of the primary containment system are:

A. To provide a barrier which, in the event of a loss-of-coolant accident (LOCA), will control the release of fission products to the secondary containment and
B. To limit the pressure increase in the containment resulting from a LOCA.

To achieve these objectives the primary containment system was designed using the following bases:

Drywell design free volume	158,236 ft^3
Drywell and pressure suppression chamber design internal pressure and temperature (See note 1)	62 psig at 281°F
Pressure suppression chamber design free volume (See note 2)	112,800 to 116,300 ft^3
Pressure suppression pool water volume(See note 2)	116,300 to 119,800 ft^3
Design leak rate	0.5% per day at 62 psig
Design code	ASME Section III
Seismic design	As specified in Section 3.8
Mark I loadings	As specified in Section 6.2.1.3.4.1

Note 1: The peak drywell (airspace) temperature at 2957 MWt is 291°F, which is above the drywell shell design temperature of 281°F. However, the drywell airspace temperature peaks briefly as shown in Figure 6.2-33. Because the drywell shell heatup is governed by heat transfer phenomena that require sustained high temperatures in the drywell atmosphere, this brief peak in the drywell airspace temperature results in a drywell shell temperature below 281°F.

Note 2: Volumes stated are based on a drywell pressure 1 psid greater than suppression chamber pressure. Original design called for a suppression chamber free volume of 117,245 ft^3. Volumes stated are a result of the Mark I Long Term Program. Refer to Section 6.2.1.3.1 for a description of the revised volume calculations.

The design volume of the drywell was dictated by the space required to contain the reactor vessel, the recirculation system, drywell cooling equipment, and reactor auxiliary equipment located in the drywell. The design free volume of the suppression chamber is based on the free volume of the drywell such that if all of the drywell atmosphere were to be discharged into the suppression chamber, the suppression chamber would remain below its design pressure.

The design pressure was established on the basis of the Bodega Bay pressure suppression tests[1] with allowance added for uncertainties. Further discussion of the applicable design code, design allowables, and test pressures is included in Section 3.8.2.1.3. Preoperational leak rate testing is discussed in Section 6.2.6.1.

The volume of water maintained in the suppression chamber was established by allowing a maximum 50°F rise in the water temperature during a LOCA. Refer to Section 6.2.1.3.1 for the sizing of the primary containment..

To minimize the release of radioactive gases during accident conditions, the design leakage rate of the primary containment was limited to as low a value as could practicably be obtained with the type of construction employed.

The design, fabrication, and inspection of the primary containment were in accordance with the requirements of ASME Section III, Class B, which pertains to containment vessels for nuclear power plants. Further discussions of the applicable design code, design allowables and test pressures are included in Section 3.8.

6.2.1.2 Design Features

This section describes the design of the major components of the primary containment. It also describes some of the modifications performed as part of the Mark I Program. The Mark I program is described in Section 6.2.1.3.4. Table 6.2-1 summarizes the design parameters of the containment system. Figures 6.2-1 through 6.2-5 show the arrangement and major components of the primary containment.

6.2.1.2.1 Drywell

The drywell is a steel pressure vessel with a removable steel head. The head and shell of the Unit 2 drywell were fabricated of SA212 Grade B plate manufactured to A-300 requirements. The Unit 3 drywell head and shell were fabricated from SA516 Grade 70, carbon steel. The top head closure is made with a double-tongue-and-groove seal, which permits periodic checks for leak tightness without pressurizing the entire containment. The top portion of the drywell vessel (the drywell head) is removed during refueling operations. The drywell head is bolted closed when primary containment integrity is required. Section 6.2.6 describes methods used to verify containment leak tightness.

The drywell shell is enclosed in reinforced concrete with concrete thickness varying from 4 to 10 feet to provide for radiological shielding and additional resistance to deformation. (Shielding calculations conservatively assume 4 to 6 feet except during preparation for refueling outages. [See reference 61) Refer to Section 12.3.2 for a discussion of the shielding analyses. At the foundation level, a sand pocket was formed to "soften" the transition between the foundation and the containment vessel. Above the foundation transition zone, the drywell shell is separated from the primary containment shield wall by a gap of approximately 2 inches to accommodate thermal expansion (see Section 6.2.1.2.1.1). Shielding in the drywell head area is provided by a concrete vault topped with removable, segmented, reinforced concrete shield plugs.

Access to the drywell is provided by a manway located on the drywell head, one bolted equipment hatch, and one personnel airlock. The manway in the drywell head has a double seal arrangement. The equipment hatch cover is bolted in place and sealed with a double-tongue-and-groove seal. The personnel airlock has two doors which open inward toward the drywell and are designed to withstand a large outward force due to a high drywell internal pressure. The doors are mechanically interlocked so that a door may be operated only if the other door is closed and locked. The seals on the doors and the manways can be tested for leakage as described in Section 6.2.6.

The normal environment in the drywell during plant operation is approximately 1 psig with a nitrogen atmosphere and a nominal bulk temperature of approximately 135°F to 150°F. This temperature is maintained by recirculating the drywell atmosphere across forced-air cooling units which are cooled by the reactor building closed cooling water system. Refer to Section 9.4.8 for a description of the drywell air cooling system.

A description of electrical, instrument, and piping penetrations and their design is provided in Section 3.8.

6.2.1.2.1.1 Drywell Expansion Gap

The steel drywell shell is largely enclosed within the structural and shielding concrete of the primary containment shield wall. To accommodate thermal expansion, an expansion gap was provided between the concrete and the drywell shell. The size of this expansion gap is shown in Figure 6.2-6 Column (a).

Both temperature and pressure cause the steel shell to expand. If temperature induced expansion were restrained by interference with the concrete structure, the resulting inward normal component could cause rippling and buckling of the steel. It is essential that a sufficient gap exists between the steel shell and the concrete structure to prevent interference due to thermal expansion.

Pressure-induced expansion results from internal forces acting outward and normal to the shell. If the concrete structure were to restrain this type of expansion, the resulting inward normal forces would tend to counterbalance the outward normal pressure-induced forces. A gap larger than that required for temperature-caused expansion is both unnecessary and undesirable. Therefore, the expansion gap was designed to accommodate the temperature induced growth of the drywell shell.

The sizing of the expansion gap was based upon an ultimate steel shell temperature of 281°F following a postulated reactor LOCA. This temperature corresponds to the temperature of saturated steam at 35 psig, which the Bodega Bay Tests[1] showed would result in the drywell following a loss-of-coolant blowdown accident. Although the drywell was designed, erected, pressure tested, and N-stamped in accordance with the ASME code using a design pressure of 62 psig, the maximum temperature was the limiting condition for the expansion gap design.

The worst case for buckling of the steel shell due to expansion occurs as a result of the largest mismatch between shell temperature and containment pressure - a high shell temperature with no pressure-caused expansion to counterbalance the external normal forces.

The worst case condition evaluation included the effects of containment spray. The results of this analysis (for a drywell condition of 281°F and 0 psig) are shown in Figure 6.2-6. This conservatively assumes that the maximum design pressure and temperature were attained, and then containment spray was initiated. The containment spray was assumed to reduce the pressure yet not cool the drywell shell. It was further assumed that the low containment pressure interlock did not function to prevent the containment spray from reducing the containment pressure to 0 psig.

With particular reference to Figure 6.2-6, the values shown for each of the vessel locations have either been derived through analysis or represent ASME Code allowable values. For the given design condition, a review of Figure 6.2-6, Columns (c) and (d), clearly shows that containment design values are not exceeded and that a sufficient safety margin exists before allowable external loadings are reached.

A combination of materials was used to permit pouring the concrete support structure over the steel drywell shell while maintaining the required expansion gap. Materials used are listed in Table 6.2-2.

The following steps were used in installing these materials:

A. Adhesive cement was applied to the drywell shell.

B. Polyester-base, flexible, polyurethane foam sheets, approximately 2¼ in. x 2 ft. x 8 ft., precut as required to fit around penetrations, were applied over the adhesive cement. The polyurethane foam sheets were tightly butted up against each other providing a continuous foam covering around the vessel. At the end of each day, all exposed polyurethane foam was covered with polyethylene-28 sheeting to protect it from the weather.

C. A 4-inch strip of masking tape was applied over the polyurethane foam at the joint location of the fiberglass cover panels. The masking tape was used as an extra precaution to prevent any epoxy in the joint from seeping into the polyurethane foam.

D. Adhesive cement was applied to the back face of the cover panel leaving a 2-inch strip around the edges free of cement.

E. Shop-fabricated, polyester-reinforced fiberglass cover panels, each with a minimum thickness of 1/4 inch and maximum thickness of 3/8 inch, were applied over the polyurethane foam leaving a 1/4-inch to 1/2-inch opening between each of panels. These panels contained 1/4-in. x 4-in. x 4-in. steel tie plates on 2-foot centers for subsequent attachment into the concrete pour.

F. The panels were temporarily held together using steel straps attached to the form studs. These steel straps served to hold the new panels in place while the joint was completed. See Figure 6.2-7a.

G. Using a special T-shaped tool, a 3-inch strip of epoxy impregnated fiberglass tape was placed behind the panel joint.

H. The joint was filled with epoxy and a second 3-inch strip of epoxy impregnated fiberglass tape was placed over the joint to complete the closure.

I. After the tie plates in the fiberglass were rigidly attached to the outside plywood forms, the fiberglass shell became the inner form for the pouring of the concrete structure.

In addition to the steps followed above, the following special precautions were taken at the junction of the expansion gap filler and pipe penetrations:

A. The polyurethane foam sheets were applied on the drywell shell tightly against the penetration.

B. The penetration pipe sleeve was placed on the penetration, stopping at the polyurethane foam sheet (i.e., 2¼ inches from the drywell shell).

C. The cover panels were placed to within approximately ¼ inch of the sleeve and the joint between the cover panels, and the sleeve was caulked with epoxy caulking.

D. Epoxy and fiberglass tape were applied to join the sleeve with the cover panels.

A diagram of the joint at pipe penetrations is given in Figure 6.2-7b.

Tests were conducted at the site on mockups of the steel and polyurethane foam/fiberglass sections to determine their displacement from a concrete pour.

These tests showed the fiberglass was displaced less than ¼ inch from the pouring and curing of concrete. From Figure 6.2-8, which shows the resilient characteristics of the polyurethane foam, it is apparent that a ¼ -inch compression of the 2-inch blanket of foam results in a negligible external pressure on the steel drywell shell. Figure 6.2-6, Column (b) shows the ASME Code allowable external loadings on the steel shell. These allowable loadings may be compared with the actual external loadings which would result from thermal expansion of the drywell with concomitant compression of the polyurethane foam. Column (c) of Figure 6.2-6, which shows these actual loadings, was based upon the stress-strain curve of Figure 6.2-8 and the thermal growth which would result from a steel shell temperature of 281°F (Column [a] of Figure 6.2-6). Column (d) of Figure 6.2-6 shows the safety factor which exists between the ASME Code allowable loadings and the actual loadings that would result from a LOCA.

The polyurethane foam material was chosen for its resistance to the environmental conditions likely to exist during its service life. In its position outside the drywell, the polyurethane foam will be exposed to a maximum radiation exposure of 2.5 x 10^7 rads, based on 40 full years of reactor operation. Radiation data [2-4] show the gamma radiation damage threshold to be between 8 x 10^6 and 4 x 10^7 rads for polyurethane elastomers. Polyurethane foam samples, similar to those used in the gap, were irradiated at various levels, from 10^7 and 10^9 rads; there was no detectable change in resilience below 10^8 rads, amply confirming the published data. Although the normal inservice temperature will be only 135°F, the polyurethane which was used has a temperature rating of 285°F.

On January 20, 1986, while maintenance work was in progress on a containment penetration for Unit 3, a fire started in the drywell expansion gap. The polyurethane in the gap burned for several hours resulting in a postulated upper bounding temperature of 500°F for both the steel containment and the primary containment shield wall. The tensile strength of the steel drywell shell reduces at temperatures above 850°F. Since the peak temperature attained during the incident was less than 500°F, it was concluded that no change occurred to the steel material properties.

Analyses were also performed to determine the possibility of thermal shock and accelerated corrosion of the drywell shell as a result of using fire suppression equipment to extinguish the fire. Both concerns were determined to have only a slight effect.

Similarly, the effect of the high temperature on the primary containment shield wall was evaluated. It was determined that the high temperature condition did not change the material properties of the concrete. Structural integrity of both the concrete and containment steel were determined not to be impaired to perform as designed in the event of a design basis accident (DBA).

On June 4, 1988, another fire started in the expansion gap of Unit 3 in basically the same area while station staff were performing maintenance similar to that performed in 1986. It was determined that this fire was bounded by the analyses conducted for the 1986 fire and no further analyses were conducted.

The design, materials, and construction of the drywell expansion gap provide sufficient space for thermal expansion of the steel drywell shell. This method of construction prevented concrete, reinforcing bars, and other foreign material from reducing the gap, thereby reducing stress risers. The primary containment can accommodate both normal operating conditions and any postulated accident conditions.

6.2.1.2.1.2 Drywell Corrosion Potential

The potential for degradation of the containment exists due to conditions that allow the introduction of water into the annulus (expansion gap) between the containment and the primary containment shield wall. Water can be introduced due to leakage of the refuel cavity past the refueling bellows drain line expansion joints during refueling or due to the introduction of water at other drywell penetrations. This water migrates to the sand pocket and then passes through the sand pocket drain lines. (See Figure 6.2-9 for details of the containment sand pocket.) If the drain lines become clogged, the water remains in the sand pocket and creates an environment that may be corrosive to the containment steel plates.

The design of the containment vessel is such that margin exists between the required shell thickness and the actual thickness of steel plate provided. A reevaluation of the required shell thickness (based on loads and data compatible with the original certified containment vessel stress report by Chicago Bridge & Iron Company) was performed on the containment shell in the region of the sand pocket. The thickness of the plates in the sand pocket region may me reduced to approximately ¼-inch below nominal and still be within ASME Code allowable stress limits.

In response to IE Information Notice 86-99 and NRC Generic Letter 87-05, an extensive review was conducted of the potential for drywell steel corrosion in the area of the containment sand pocket. This review included the following:

A. Inspection of the drain lines,

B. Initiation of a surveillance program to detect leakage into the annulus, and

C. An evaluation of the actual plate thickness at Dresden Unit 3.

Initially, all lines in both units were found to be clogged. After the lines were cleared, leakage from all lines was observed. The source of the leakage is believed to be past the refueling bellows drain line expansion joints. The method utilized to plug the drain lines during refueling is the installation of an expanding stop plug, which if incorrectly placed in the expansion joint, could produce leakage. In an effort to eliminate leakage, the plug design was altered to preclude incorrect placement. Water samples taken were tested and determined to be noncorrosive in nature, so there was no immediate safety concern. This, however, did not prevent future leakage.

Ultrasonic test (UT) results indicated that over 18 years of operation of Dresden Unit 3, no detrimental corrosion has occurred in the drywell steel plate at the sand pocket level. This conclusion is further supported by the fact that all of the thickness measurements were on the high side (greater than the nominal 1.0625-inch thickness). These results have been obtained in spite of the fact that substantial moisture has previously been found in the sand pocket. Finally, a surveillance procedure has been established to monitor sand pocket drain lines during refuel activities. If leakage is detected during refuel flood-up, an inspection to determine the source will take place and further corrective measures will be initiated.

Refer to Section 6.1 for a description of the containment coating system and the corrosion resistance results obtained.

6.2.1.2.2 Vent System

Eight large circular vent lines form a connection between the drywell and the pressure suppression chamber. Referring to Figures 6.2-2, 6.2-3, and 6.2-4, jet deflectors at the drywell entrance to each vent line prevent possible damage to the vent lines from jet forces which might accompany a pipe break in the drywell. The drywell vent lines are connected to a vent header, which is contained within the airspace of the suppression chamber. The vent header has the same temperature and pressure design requirements as the vent lines. Each vent line is welded to the drywell and then passes through the suppression chamber to the suppression chamber vent header, where it is also welded. The design of the drywell considers the vent system (vent lines, vent header, and downcomers) as an appendage to the drywell. The seismic induced lateral loads are taken by the drywell. The vent lines penetrate the torus through larger diameter pipe sections which are welded to the suppression chamber. Bellows seals connect the other end of the larger pipe sections to the vent lines. The bellows permit lateral movement of the vent lines and act as part of the containment pressure envelope.

Projecting outward and downward from the vent header are 96 downcomers arranged in pairs which terminate below the water surface of the suppression pool. The upward reaction from the downcomers is resisted by columns between the vent header and the bottom of the suppression pool. The columns are pinned top and bottom to accommodate the differential horizontal movement between the header and the pressure suppression chamber. The downcomers are braced both laterally and longitudinally (Mark I Containment Long-Term Program). Vent header deflectors, shown in Figure 3.8-18, are provided in both the vent line bays and nonvent line bays. The deflectors shield the vent header from pool swell impact loads (see Section 6.2.1.3.4.1) which occur during the initial phase of a DBA. The vent system is supported vertically by two column members at each miter joint location (see Figure 6.2-5). Horizontal support is provided by the vent lines which transfer lateral loads acting on the vent system to the drywell at the vent line/drywell penetration locations. The vent system also provides support for a portion of the safety-relief valve (SRV) piping inside the vent line and suppression chamber as shown in Figures 6.2-4 and 3.8-24. Loads acting on the SRV piping are transferred to the vent system by the penetration assembly and internal supports on the vent line.

6.2.1.2.3 Pressure Suppression Chamber

As shown in Figures 6.2-3, 6.2-4, 6.2-5, and 3.8-18, the pressure suppression chamber is a steel pressure vessel in the general shape of a torus, symmetrically encircling the drywell. The circular path around its major axis is formed by 16 cylindrical segments or bays. Alternate bays (eight in all) are connected to vent lines leading from the drywell. The horizontal centerline of the suppression chamber is located slightly above the bottom of the drywell. The inside diameter of the mitered cylinders, which make up the suppression chamber, is 30 feet 0 inches. A reinforcing ring with two column supports and a "saddle" is provided at each miter joint (Mark I Containment Long-Term Program) to transmit dead loads and seismic loads to the reinforced concrete foundation slab of the reactor building.

The reinforcing ring at each miter joint is in the form of a T-shaped ring girder. The ring girder is braced laterally with stiffeners connecting the ring girder web to the suppression chamber shell.

The suppression chamber shell thickness is typically 0.585 inches above and 0.653 inches below the horizontal centerline, except at penetration locations where it is thicker.

The suppression chamber is anchored to the basemat by a system of base plates, stiffeners, and anchor bolts. Space is provided outside of the chamber for inspection and maintenance.

Two manholes with double-gasketed bolted covers provide access from the reactor building to the pressure suppression chamber. These access ports are bolted closed when primary containment integrity is required. They are opened only when the primary coolant temperature is below 212°F and the pressure suppression system is not required to be operational. A test connection between the double gaskets on each cover permits checking gasket leak-tightness without pressurizing the containment.

Original plant design included baffles in the suppression pool intended to aid in thermal mixing of the suppression pool water. As a result of a reevaluation of the necessity for these baffles and a concern for their continued structural integrity in a blowdown event, the baffles have been removed.

The suppression chamber can be drained using the low pressure coolant injection (LPCI) pumps discharging via the LPCI heat exchanger to either radwaste or the condenser hotwell until the LPCI pumps lose suction. However, the path to the condenser hotwell is the preferred route to minimize the volume of water to be processed by radwaste. Complete suppression pool draining can be accomplished even with the LPCI pumps out of service by use of specially installed piping and isolation valves.

6.2.1.2.4 Primary Containment Vacuum Relief Devices

Automatic vacuum relief devices for the drywell and suppression chamber prevent the primary containment from exceeding the design external-to-internal pressure differential. The primary containment is designed for a maximum external pressure of 2 psi greater than the concurrent internal pressure for the drywell and 1 psi for the suppression chamber.

The drywell vacuum relief valves allow gas to be drawn from the pressure suppression chamber, and the pressure suppression chamber vacuum relief valves allow air to be drawn from the reactor building.

6.2.1.2.4.1 Reactor Building-to-Containment Vacuum Relief

To prevent torus collapse due to excessive external-to-internal pressure differential, a vacuum breaker system is provided connecting the suppression chamber airspace with the reactor building atmosphere. The system consists of two parallel lines with each line containing two vacuum breaker valves in series. One of the series valves opens at high differential pressure and fails open on loss of instrument air or electrical power. To ensure proper operation of these valves, an air accumulator with adequate volume to open the valve once is provided. The normal power supply to the valve solenoid is backed-up by another source of power, in addition to having the capability of being energized by the emergency diesel generators. The second vacuum breaker valve is a check valve that opens when high differential pressure occurs across the disk. The combined pressure drop at rated flow through both valves does not exceed the difference between suppression chamber design external pressure and maximum atmospheric pressure.

The quick actuation time of these valves was found to cause both abnormal seat wear and misalignment of the valve disc. To provide a slower and more controlled cycling of these valves, speed control valves were installed to regulate the airflow between the solenoid and the air cylinder of the relief valves.

The piping system is designed to the Boiler and Pressure Vessel (B&PV) Code B31.1. Lines 2(3)-1601-A(B)-20" were analyzed to the latest Mark I design criteria (NUREG-0661, Revision 1) to verify that the modification met the requirements of ASME Section III, Subsection NC, 1977 edition with Summer 1977 Addenda. Due to the insignificant component mass of the speed control valve (3 pounds), a revision to the Mark I piping analysis was not required. However, the Mark I calculations were updated to document the installation of this modification.

Valve operational testing requirements for ANSI/ASME OMa-1988, Part 10, Category A valves apply to the 2(3)-1601-20 A and B valves and their actuators. Valve closing time shall be 2 to 5 seconds. Valve opening time is 5 to 30 seconds.

Section 6.2.1.2.4.2 identifies the bounding drywell depressurization transient to result from drywell spray actuation following a LOCA. Based on analyses for these types of events, it has been demonstrated that although these events result in depressurization of the drywell and torus, the depressurization is not sufficient to reduce the torus pressure below atmospheric pressure (14.7 psia). Therefore, the reactor building-to-suppression chamber vacuum breakers will not open for these events.

However, in order to verify that the reactor building-to-suppression chamber vacuum breakers are adequately sized and operate in sufficient time to ensure torus integrity, an analysis was performed for a postulated event where the vacuum breakers will open.

Three cases were considered in the safety analyses to determine the adequacy of the external vacuum breakers:

a) Inadvertent actuation of one torus spray loop during normal operation;
b) Inadvertent actuation of one torus spray loop during normal operation with the suppression chamber free air volume completely filled with saturated steam; and
c) Inadvertent actuation of one torus spray loop during normal operation with the suppression chamber free air volume filled with an air/steam steam mixture.

The results of these three cases show that the external vacuum breakers with an opening setpoint of 0.5 psid are capable of maintaining the differential pressure within design limits.

6.2.1.2.4.2 Torus-to-Drywell Vacuum Relief

As shown in Figure 6.2-10, six vacuum breaker assemblies, exterior to the suppression chamber, connect the suppression chamber and drywell, each assembly having two 18-inch swing check valves arranged in parallel. The valves operate as free-swinging, gravity-closing-type check valves with no external power sources. The lines were sized on the basis of the Bodega Bay pressure suppression system tests. Their chief purpose is to prevent excessive water level variation in the submerged portion of the vent discharge downcomers prior to a large break LOCA. The Bodega Bay tests regarding vacuum breaker sizing were conducted by simulating a small break LOCA, which tended to cause downcomer water level variation, as a preliminary step in the large break test sequence. The vacuum breaker capacity selected on this test basis is more than adequate (typically by a factor of four) to limit the pressure differential between the suppression chamber and drywell during post-accident drywell cooling operations to below the design limit.

An analysis of the drywell negative pressure protection requirements was performed to confirm the adequacy of the vacuum breaker design to limit the drywell negative pressure to a maximum of 2 psid with respect to the suppression chamber.

The adequacy of the torus-to-drywell vacuum breakers was determined based on three transient events which conservatively bound the vacuum breaker sizing requirements. The three events are:

1. Inadvertent Spray Operation – The plant is assumed to be operating at normal conditions and the drywell sprays are actuated.

2. Drywell Spray Following a LOCA – Drywell sprays are actuated following a LOCA event. All of the drywell air is assumed to be purged to the torus free space and the drywell contains saturated steam. To analyze this event, both drywell spray loops were assumed to be simultaneously actuated.

3. Vessel Overflow Through Break – For this case, the drywell sprays are not used for condensation. Instead, it is assumed that, following a LOCA, the flow of water entering the reactor pressure vessel cascades through the break and condenses the steam contained in the drywell.

The analyses concluded that of the 12 vacuum breakers, five complete assemblies or as few as eight vacuum breakers, consisting of two assemblies and four inboard vacuum breakers, are adequate to keep the pressure differential below 2 psid. This conclusion is based on results from the bounding drywell depressurization transient which occurs when the maximum possible flowrate from the reactor pressure vessel discharges into the drywell following a LOCA.

However, the HPCI and LPCI systems are not capable of injecting at their maximum flow rate simultaneously. Summing the HPCI and LPCI flow at varying pressure shows the actual maximum flow rate to be less than LPCI flow at zero psig. Therefore, the analysis shows that any 8 vacuum breakers are adequate to keep the pressure differential below 2 psig for the maximum possible depressurization event.

The vacuum breaker sizing requirements, as a function of valve opening time for the vessel overflow after LOCA transient, are presented in Figure 6.2-11. The figure presents results for both 0.2 and 0.5 psid pressure setpoints. Valves with characteristics that fall within the acceptable region of the figure satisfy both the 2.0 psid design criteria and prevent water from entering the ring header during the transient. The latter condition is imposed because if water were to enter the ring header, the steam condensation rate in the ring header could significantly increase. The potential then exists to draw water into the drywell through the main vent which would interfere with the vacuum breaker operation, producing a more severe drywell depressurization.

Figure 6.2-11 also indicates that with the 12 existing vacuum breakers, the valve opening time cannot exceed 2.25 and 1.75 seconds for pressure setpoints of 0.2 and 0.5 psid, respectively.

The vacuum breaker assemblies are located within a 225° arc to the north side of the torus. In the event that vacuum breakers are sealed or removed, the two outermost assemblies (located at azimuthal angles of 112° 30' and 247° 30') should remain operable, if possible, to achieve symmetric depressurization of the drywell.

A number of improvements have been made to these valves subsequent to initial plant licensing. The valve seats have been replaced by seats made of ethylene-propylene, the valve disk hub has been replaced by a 304 stainless steel hub, the valve disk has been changed from cast aluminum to wrought aluminum, and new phosphor-bronze shaft bushings and seals with ethylene-propylene O-rings have been installed to replace the original teflon bushings which tended to cause the valve to stick.

To monitor the valve disks for proper closure, the position indication switches have been modified to allow detection of valve opening in excess of 1/16 inch.

Subsequent to the installation of the wrought aluminum disks, an analysis was performed to determine the structural integrity of the vacuum breaker valves under postulated hydrodynamic loads in a post-LOCA condition. Refer to Section 6.2.1.3.5.2.7 for a discussion of condensation oscillation and chugging phenomena. Results of this analysis indicated that all stresses were within the allowable limits as defined in ASME Section III, Subsection NC for Class 2 Components, 1977, including the Summer 1977 addenda.

Following this analysis, a refined load evaluation resulted in lower pallet impact velocities than originally calculated. The refined analysis shows that the vacuum breakers will not actuate during the chugging transient. The NRC has evaluated these analyses and concluded the existing vacuum breaker design is adequate.

6.2.1.2.5 Drywell Pneumatic System

The drywell pneumatic system takes a suction from the drywell atmosphere and compresses the gas (either air or nitrogen) for use by pneumatically operated equipment in the containment. The drywell pneumatic system is described in Section 9.3.

6.2.1.2.6 Drywell-to-Suppression Pool Differential Pressure Control System

During normal operation, a system consisting of two 100% design capacity compressors, a receiver, differential pressure control, and associated piping maintains a pressure differential between the drywell and the suppression chamber (see Drawings M-25 and M-356). This system is referred to as the pumpback system. The pumpback system maintains drywell pressure slightly above suppression chamber pressure to decrease the amount of water standing in the downcomers. This decreases the dynamic forces on the suppression chamber during a postulated LOCA. During normal operation, a compressor takes suction from the suppression chamber free air volume via the nitrogen supply line and discharges to an air receiver. Air from the receiver is discharged to the drywell through a differential pressure control valve to maintain a pressure differential. The minimum drywell-to-suppression chamber differential pressure of 1.0 psi was determined during the Mark I Short-Term Program to provide the required safety margin in the suppression chamber design. All controls are in the control room.

In the event that both compressors are unavailable, the differential may be maintained by the nitrogen inerting system. Refer to Section 6.2.5 for a description of the nitrogen inerting system.

The pumpback system is cross-connected with the drywell pneumatic system and supplies compressed gas to the associated instruments and actuators. The reverse is not true, however, since the capacity of the drywell pneumatic compressors is not sufficient to maintain a 1-psi differential from the drywell to the torus. The drywell pneumatic system is discussed in Section 9.3.

6.2.1.2.7 Containment Venting

A primary containment system vent is provided which is normally closed. The vent design permits the vent discharge to be routed to the standby gas treatment system (SBGTS) or the reactor building ventilation system so that release of gases from the primary containment is controlled, with the effluents being monitored before discharge through the stack. Test connections are provided between the double inlet and outlet vent valves to permit checking for leaktightness in accordance with 10 CFR 50, Appendix J as described in Section 6.2.6.

The containment may be vented to minimize pressure fluctuations caused by air temperature changes during various operating modes. This is accomplished through ventilation purge connections, which are normally closed while the reactor is at a temperature greater than 212°F. The suppression chamber may be vented separately.

Purging and venting will be strictly limited to those operations necessary to inert or deinert the containment, control containment pressure, reduce containment oxygen concentration, or establish and maintain a pressure differential between the drywell and suppression chamber. The containment vent, purge, and inerting system is described in Section 6.2.5. Also refer to Section 6.2.7 for a description of the augmented primary containment vent system (APCVS).

As shown in Drawings M-25 and M-356, the purging and venting system consists of 18-inch, 6-inch, and 2-inch containment isolation valves that automatically close on either high drywell pressure, drywell high radiation, or reactor low water level signals (Group 2). Refer to Section 6.2.4.2.4 for a description of these isolation valves.

6.2.1.2.8 Containment Instrumentation

A suppression pool temperature monitoring system is installed to provide average and local pool temperature indication and alarms in the control room.[5] Sixteen thermocouples are installed around the torus, one in each torus bay, with a set of eight thermowells on the inner circumference, and another set of eight thermowells on the outer circumference, forming two independent channels. They are placed below normal water level, near the normal center of gravity of the water mass and horizontally equidistant. The individual sensors for each channel are continuously recorded in the control room.

The original containment pressure and suppression pool water level instruments have been modified to meet the requirements of NUREG-0578, Section 2.1.9 to provide a wider range of indications. Both instruments provide indication in the control room. Water level indication is from the bottom to near the top of the suppression pool. This indication allows determination of suppression pool water inventory during emergency conditions. The pressure instrument displays pressures from -5 psig to four times containment design pressure (62.5 psig) or 250 psig.

The drywell temperature monitoring system monitors drywell temperature at predetermined locations and records the temperatures so that the temperature effects on environmentally qualified (EQ) equipment located in the drywell can be determined.

As a result of the Unit 2 drywell high temperature event,[6] the location of the Unit 3 drywell thermocouples in relation to the EQ equipment was evaluated. The analysis revealed that only 12 of the 28 drywell thermocouples monitored EQ equipment. As a result, existing thermocouples which previously monitored areas with non-EQ equipment were relocated to areas near EQ equipment.

Similarly, various Unit 2 drywell thermocouples were relocated to provide more meaningful temperature indications.

To meet Regulatory Guide 1.97 requirements, eight drywell atmosphere thermocouples have been environmentally qualified. Refer to Section 3.11 for a description of the EQ Program and to Section 7.5 for a description of the R.G. 1.97 Program.

6.2.1.3 Design Evaluation

6.2.1.3.1 Sizing of the Primary Containment

The design parameters for the primary containment system are based on data obtained from the Bodega Bay tests, conducted for Pacific Gas and Electric Company (PG&E) at the Moss Landing steam plant in 1962.[1] By juxtaposition of the Unit 2 and 3 data with the Bodega Bay data, the following design values were determined.

A. The drywell and suppression chamber and connecting vent system tubes are designed for 62 psig internal pressure at 281°F. The application of the Bodega Bay pressure suppression test data to the Dresden primary containments established a drywell pressure of 62 psig (including a 10 psi margin) and a suppression chamber pressure of 35 psig (including a 5 psi margin) as design requirements. To simplify pressure tests of the primary containment, the suppression chamber design pressure was set equal to that of the drywell, at 62 psig. The drywell and connecting vents are designed for an external-to-internal pressure differential of 2 psi at 281°F, and the suppression chamber is designed for an external-to-internal pressure differential of 1 psi at 281°F. The peak drywell (airspace) temperature at 2957 MWt is 291°F, which is above the drywell shell design temperature of 281°F. However, the drywell airspace temperature peaks briefly as shown in Figure 6.2-33. Because the drywell shell heatup is governed by heat transfer phenomena that require sustained high temperatures in the drywell atmosphere, this brief peak in the drywell airspace temperature results in a drywell shell temperature below 281°F.

B. The drywell is designed to withstand a local hot spot temperature of 300°F with a surrounding shell temperature of 150°F, concurrent with the design pressure of 62 psig.

C. The minimum total vent line cross-sectional area is the total design accident break flow area, divided by 0.0194. The entrance area around the jet deflection baffles from the drywell to the vent lines is a minimum of 1.4 times the vent line area to minimize entrance losses.

D. The ASME Code impact test requirements for materials used for pressure-containing parts of the primary containment vessel call for the establishment of the lowest metal temperature that will be experienced while the unit is in operation. The lowest temperature to which the primary containment vessel pressure-containing parts could actually be subjected while the unit is in operation is 50°F, because the primary containment system is housed in a building which is maintained at or above this minimum temperature during reactor operation, and the containment vessel pressure-containing parts would be maintained at or above this temperature while subjected to post-accident design loadings. To provide an additional factor of safety, the design basis minimum service metal temperature was established as 30°F.

The size of the reactor vessel and associated auxiliary equipment dictated the required drywell dimensions. The lower part of the drywell is a sphere with an inside diameter of 66 feet; the upper part of the drywell is a cylinder 46 feet high with an inside diameter of 37 feet.

The volume of the drywell vessel, including connected vent lines is:

Gross Volume	198,440 ft^3
Occupied Space	40,204 ft^3
Net Free Volume	158,236 ft^3

The total volume of the coolant in the reactor process system, which could be discharged into the drywell and carried over into the suppression chamber during an accident, was calculated to be 10,030 cubic feet. This calculation considered the reactor coolant system, the recirculation system, the main steam system, the feedwater system, the cleanup system, the isolation condenser system, and the shutdown cooling system.

The amount of water required to absorb the reactor system sensible heat was based upon a 50°F rise in the suppression chamber water temperature, 10 seconds of full power operation, and a temperature reduction from 550°F to 281°F for the reactor vessel and internals, reactor coolant, recirculation water, main steam system, feedwater system, cleanup system, shutdown cooling system, and isolation condenser system. The minimum water volume required to meet these criterion was calculated to be 112,200 cubic feet.

The size of the suppression chamber was calculated using the gas law equation, performing a ratio for initial and final conditions and solving for V_2:

$$V_2 = \frac{P_1 V_1 T_2}{P_2 T_1}$$

where:

V_2 = V_{aw} (gas volume of suppression chamber) - 10,030 ft^3 (carryover volume)

V_1 = V_D (volume of drywell) + V_{aw}

P_1 = 14.7 + 0.5 - 0.8 (vapor pressure of water at T_1) = 14.4 psia

P_2 = 29.0 + 14.7 - 3.3 (vapor pressure of water at T_2) = 40.4 psia

T_1 = 555°R (95°F) (operational temperature limit)

T_2 = 605°R (145°F)

From this it was determined that:

V_{aw} = 117,000 ft^3

This value represents the free volume required in the gas space of the suppression chamber to limit the suppression chamber pressure to 29 psig at 145°F assuming an initial pressure of 0.5 psig at 95°. This volume was used to calculate the required suppression chamber dimensions as described below.

The design suppression chamber water volume was determined to be 115,600 ft^3. This provides the minimum volume required for heat absorption, 112,200 ft^3, plus 3,400 ft^3 for level control.

The structural material volume, which includes structural members within the suppression chamber and the contained volume of vent piping, was determined to be 14,400 ft^3. Combining these volumes yielded:

Gross Volume of Suppression Chamber = 247,000 ft^3

From this calculated value for the gross volume of the suppression chamber, the suppression chamber dimensions of 109-foot major diameter with 30-foot minor diameter were derived. As a result of modifications made during the Mark I

Program, the gross volume was recalculated by more precise methods as described below.

The vent pipe area is equal to the design accident flow area divided by 0.0194, in accordance with the Bodega Bay test results. The as-installed design consists of eight vent pipes having a total minimum area of 302 square feet. This area results in the peak drywell containment pressure following the accident as discussed in Section 6.2.1.3.2.

Subsequent to the initial design calculations, as a result of the Mark I Containment Program, the following values have been established for the suppression chamber:

Gross volume of suppression chamber	245,400 ft^3
Downcomer submergence	3.67 ft to 4.0 ft
Water volume	116,300 ft^3 to 119,800 ft^3
Air volume	112,800 ft^3 to 116,300 ft^3
Structural material volume	12,100 ft^3
Volume associated with 1.0-psi drywell-to-suppression chamber differential pressure	700 ft^3

The revised gross volume of the suppression chamber (245,400 ft^3) was calculated based on actual as-constructed dimensions. The water volumes were calculated based on water levels corresponding to a downcomer submergence of 3.67 feet to 4.0 feet, as analyzed in the Mark I Containment Program. The structural material volume was calculated based on the Mark I modifications and the removal of suppression pool baffles. A differential pressure of 1.0 psi between the drywell and the suppression chamber, which was established during the Mark I program as an operational requirement to mitigate hydrodynamic loads, results in a 700-cubic foot displacement of suppression pool water. Based on these values, the remaining air volume was established.

In conjunction with the Mark I Containment Program, a plant unique structural analysis [7] was performed for Dresden Units 2 and 3. This analysis was based on pool swell loads [8] determined from plant unique tests. These tests were based on a downcomer submergence of 3.67 - 4.00 feet. The suppression chamber water and airspace volumes corresponding to these submergences were taken from the FSAR as 112,203 - 115,655 ft^3. Modifications were performed based on these analyses to restore the margin of safety required in the original containment design.

After completion of the Mark I Containment Program, it was determined that the water volumes specified in the plant unique load definition [8] and the plant unique analysis[7] actually correspond to a downcomer submergence of 3.21 to 3.54 feet at zero differential pressure. An evaluation concluded that affected components were still within the allowables established for the Mark I Containment Program[9]. This evaluation concluded that the present volume, corrected for the 1.0 psid overpressure in the drywell, does not adversely affect the existing analyses, and that the maximum component stresses reported in the plant unique analysis are still valid and meet the criteria of NUREG-0661. See Section 6.2.1.3.6.2 for additional discussion of the Mark I acceptance criteria. Refer to Section 6.2.1.3.6.4.2 for a description of the details of the reevaluation.

A plant unique structural analysis was performed based on operation at full power of 2957 MWt. The suppression chamber water and airspace volumes were 115,000 and 112,800 ft^3. The analysis were compared to loads (Reference 71) determined from plant unique tests. The calculated dynamic loads (pool swell, vent thrust, condensation oscillation, and chugging) analyzed at 2957 MWt are bounded by their respective loads already defined (see Sections 6.2.1.3.4, 6.2.1.3.5 and 6.2.1.3.6).

6.2.1.3.2 Containment Response to a Loss-of-Coolant Accident

In order to identify containment response to a loss of coolant (LOCA) accident, several analyses were performed. These analyses were performed to evaluate the containment short-term and long-term pressure and temperature response following the Design Basis Accident (DBA) LOCA. The containment analyses uses the General Electric methodology, which has been reviewed and approved by the NRC. The M3CPT code (Reference 62) is used to model the short-term (up to 30 seconds) DBA-LOCA containment pressure and temperature response. The LAMB code (Reference 66) is used to generate the break flow rates and break flow enthalpies that serve as inputs to M3CPT. The SHEX code (References 62 and 69) is used to analyze the containment pressure and temperature response for other than the short-term DBA-LOCA.

Containment pressure and temperature responses were calculated for Dresden Units 2 and 3 for DBA, IBA, and SBA conditions as well as calculations to support assessment of minimum NPSH availability. These calculations were based on operation at full power of 2957 MWt with the operational pressure difference between the drywell and wetwell.

The containment analysis for GE14 fuel bounds the SVEA-96 Optima2 fuel in the Dresden reactors (Reference 74).

6.2.1.3.2.1 Containment Short-Term Response to a Design Basis Accident

The spectrum of postulated break sizes with respect to reactor core response is discussed in Section 6.3.3.2. The following information covers the effects of a LOCA on the containment, with particular emphasis on the most severe break: the doubled-ended rupture of one of the 28-inch-diameter recirculation pump suction lines. For the purpose of sizing the primary containment, an instantaneous, circumferential break of this line was hypothesized. The LOCA involving the recirculation pump suction line would occur upstream of point 1 on Figure 6.2-14.

For the vessel blowdown, the reactor was assumed to be operating at 102% of full power of 2957 MWt, or 3016 MWt.

If the equalizer line valve is closed (the normal operating condition), the flow will choke in the nozzles of the 10 jet pumps on the jet pump header of the broken line. The total blowdown flow area in the limiting case is 4.261 ft^2.

Power production in the reactor was assumed to cease essentially at time zero due to void formation, as well as scram. Release of the sensible heat stored in the fuel above 545°F and the core decay heat was included in the vessel blowdown calculation. The rate of energy release was calculated using a conservatively high heat transfer coefficient throughout the blowdown. Because of this high energy release rate, the vessel would be maintained at near rated pressure for almost 10 seconds. The high vessel pressure increases the calculated blowdown flowrate, which is conservative for containment analysis purposes.

With the vessel fluid temperature remaining near 545°F, the release of sensible energy stored below 545°F is negligible during the first 10 seconds; the later release of this sensible energy does not affect the peak drywell pressure. The small effect of this energy on the end-of-transient pool temperature is included in the calculations.

The main steam isolation valves were assumed to start closing at 0.5 seconds after initiation of the accident, and were assumed to close at the fastest possible rate (3.5 seconds to fully closed). Actually, the isolation signal is expected to come from reactor low-low water level, so these valves may not receive a signal to close for over 4 seconds, and the closing time could be as high as 5 seconds. Assuming rapid closure of these valves maintained the reactor vessel at a higher pressure during the blowdown, resulting in a calculated drywell pressure transient more severe than actually expected.

The relatively cold feedwater flow, if considered, tends to depressurize the reactor vessel, thereby reducing blowdown flowrates. Therefore, the feedwater flow was conservatively assumed to stop instantaneously at time zero.

The GE computer code M3CPT is used to analyze the short-term response of pressure suppression containment system to LOCA events where the primary system rupture occurs within the drywell. The basic containment modeling used in M3CPT is described in Reference 62. The M3CPT code models the containment system as three separate but interrelated models; namely, the vessel blowdown model, drywell model and wetwell model. The code calculates the pressure and temperature histories of the drywell and wetwell and the mass and energy interchange between these volumes and the reactor primary system. The use of the M3CPT code has been accepted by the NRC for calculating the short-term response of the containment system to LOCAs from the start of the transient until operator intervention via Automatic Depressurization System (ADS) or until the reactor blowdown is complete, whichever comes first. The GE containment analysis methods have been reviewed by the NRC (References 63, 64 and 65).

For the containment response analysis, these break flows and break enthalpies are calculated with the LAMB code. Reference 66 describes the more detailed LAMB vessel model used to calculate break flow rates used as input to the M3CPT code. For the 2957 MWT analysis, the LAMB blowdown flow rates, used as input to M3CPT, are calculating using Moody's Slip flow model (Reference 67). The Slip flow model is a conservative model and is the same model used in Appendix K calculations.

The use of the LAMB blowdown flow in M3CPT was identified in Reference 68 by reference to the LAMB code qualification in Reference 66. The M3CPT code itself is still used to calculate the drywell pressurization rate, vent clearing time, vent clearing pressure and peak drywell-to-wetwell pressure difference, used in evaluating the DBA-LOCA hydrodynamic loads.

The GE computer code SHEX is used to perform the analysis of the long-term containment pressure and temperature responses to LOCAs and transients until after the suppression pool temperature peaks. The key models used in the SHEX code are described in References 62 and 69. This methodology is consistent with Reference 68. The SHEX code uses a coupled pressure vessel and containment model. The code performs fluid mass and energy balances on the reactor primary system, the suppression pool, and the drywell and wetwell airspace. The Boiling Water Reactor (BWR) primary system, feedwater system, Emergency Core Cooling System (ECCS), and SRVs are also modeled to the extent that their response affects that of the containment system. The code calculates the suppression pool bulk temperature, and the pressures and temperatures in the drywell and wetwell airspaces.

The use of the SHEX code has been accepted by the NRC (Reference 70) for calculating the response of the containment during an accident or a transient event and has been applied to the evaluation of containment response for many BWR plants.

The SHEX code is used to perform the long-term containment analysis (after 600 seconds when containment cooling operation is assumed) as well as the short-term (defined here as the first 600 seconds) and long-term containment analyses for the NPSH evaluation. Reference 70 provides NRC's acceptance of the usage of the SHEX code in the analyses of long-term containment pressure and temperature response.

The drywell pressure response was calculated using an analytical model developed on the basis of the Bodega Bay and Humboldt Bay pressure suppression tests at the Moss Landing facility. The model has been found to accurately predict the test data over a wide range of system parameters.

The drywell pressure response calculation utilizes Moody's model. Using the blowdown rates calculated using Moody's model, the pressure response of the containment was calculated using the following assumptions:

A. Thermodynamic equilibrium exists in the drywell and suppression chamber;

B. The composition of the fluid flowing in the vents is based on a homogeneous mixture of the fluid in the drywell;

C. The flow in the vents is compressible except for the liquid phase;

D. There is no heat loss from the contained gases.

Concerning the first assumption, a gas mixing analysis has shown that the system pressure changes by only 2 psi if complete separation of the air and steam is assumed. Since complete mixing should be nearly achieved, the error due to assuming complete mixing would be negligible and in the conservative direction. Therefore, the following general equilibrium state relationship was used in the analysis:

$$E_D/M_{WD} = e_f + (e_{fg}/v_{fg})\,(V_D/M_{WD} - v_f) + C_{va}\,(M_{aD}/M_{WD})\,(T_D + 460) \qquad (3)$$

E_D = Total internal energy in the drywell

M_{WD} = Mass of steam and water in the drywell

M_{aD} = Mass of air in the drywell

V_D = Free volume of the drywell

T_D = Temperature of the drywell, °F

e_f, e_{fg} = Specific internal energy of saturated liquid and vaporization, respectively

v_f, v_{fg} = Specific volume of saturated liquid and vaporization, respectively

C_{va} = Specific heat at constant volume of air

Application of the second assumption results in complete liquid carryover into the drywell vents. Realistically, some of the liquid would remain behind in a pool on the drywell floor. Thus, the calculated drywell pressure is conservatively high.

In the development of the drywell flow model, it was noted that the mass fraction of liquid in the drywell was on the order of 0.60, while the volumetric fraction was only about 0.005. This fact resulted in the following interpretation of the flow pattern. The liquid is in the form of a fine mist that is carried along by the predominately steam airflow which affects the inertia term of the momentum equation. Except for this modification, the flow was treated as compressible flow of an ideal gas in a duct with friction. The loss coefficients of the vent / vent-header / downcomer system were lumped as an equivalent length of pipe.

The accuracy of this interpretation with respect to the effects of liquid carryover is supported primarily by the Humboldt Bay pressure suppression tests.[12] In this series of tests, changes in the drywell geometry resulted in variations in the amount of liquid carryover achieved. The liquid remaining in the drywell at the end of the test was measured and recorded. Fortunately, these tests were performed with a relatively small diameter orifice so that the vessel blowdown can be accurately calculated using Moody's critical flow model.[10] In Figure 6.2-15, the calculated and measured pressure responses for these tests are shown. Note that with 100% carryover, the agreement was excellent. In that test, the drywell was preheated to 184°F before the blowdown was started, which prevented any condensation on the drywell walls. A calculated response with the effects of condensation considered and with no carryover is also shown in Figure 6.2-15. Again, the agreement with the measured response was excellent.

The model has been checked against both the Humboldt Bay and Bodega Bay pressure suppression tests for a wide range of break sizes. Due to the overprediction of blowdown flowrates, as discussed in the previous paragraphs, the model was found to overpredict most existing test data. For those tests where the blowdown was accurately predicted, the drywell response was also accurately predicted. The model has been compared against the test data for two of the smaller orifices tested in Figures 6.2-16 and 6.2-17. As can be seen in the figures, the vessel blowdown was accurately reproduced for these tests. The drywell pressure response was slightly overpredicted. The overprediction is believed to be due to a combination of no condensation assumed in the calculated response, slight overprediction of vessel blowdown flowrates, and incomplete liquid carryover into the drywell vents.

As the size of the vessel orifice increases, the vessel blowdown rate is overpredicted and the overprediction of peak drywell pressure increases. This trend is illustrated in Figure 6.2-18, where calculated and measured peak drywell pressures are compared. It is important to note that in no case did the model underpredict the test data.

The temperature, pressure, and relative humidity assumed in the drywell were based on conservative estimates of normal operating values. A steam prepurge of the drywell was not assumed for two reasons:

A. Reactor scram due to high drywell pressure precludes complete prepurging of the drywell and

B. The prepurging of the drywell only increases the peak drywell pressure by approximately 1 psi.

Statement B may appear to contradict existing test data which shows as much as an 11-psi increase in peak drywell pressure due to prepurging. This apparent disparity is attributable to the effects of two phenomena discussed below.

A. Condensation on drywell walls: Due to the high ratio of drywell wall surface area to blowdown flow area, the effects of condensation reduced the peak drywell pressure in tests with cold drywell walls. Prepurging eliminated any significant surface condensation, and higher peak drywell pressures resulted. The calculation of peak drywell pressure did not take credit for surface condensation with or without prepurging.

B. Liquid carryover into drywell vents: The calculation of peak drywell pressure assumes complete carryover of all liquid in the drywell into the drywell vents which increases the peak drywell pressure. However, test data from the Humboldt Bay series of pressure suppression tests[12] reveal that carryover is more likely to be complete if the drywell is initially hot. Hence, the increased carryover would increase the measured pressure compared to a test with less carryover; i.e., one with no purge. Hence, prepurging of the drywell does not significantly affect the peak drywell pressure so long as condensation is neglected and complete liquid carryover is assumed for both the prepurged and nonprepurged cases.

The pressure and temperature response of the containment for 2957 MWt are calculated using the General Electric methodology which has been reviewed and approved by the NRC. The short-term pressure responses are shown in Figure 6.2-31 with a peak drywell pressure of 43.9 psig, which is well below the design pressure of 62 psig. The short-term suppression pool temperature are shown in Figure 6.2-33.

Additional analyses of the containment pressure and temperature response to small break accidents (SBA), intermediate break accidents (IBA), and the DBA were conducted as part of the Mark I Program. Refer to Section 6.2.1.3.6.4 for a description of these additional analyses.

On June 5, 1970, Dresden Unit 2 experienced a transient which caused a safety valve to open and fail to reseat. As a result, the containment atmosphere is postulated to have reached 320°F after approximately 1 hour. A general case in which the containment wall is postulated to be 340°F has been analyzed to demonstrate the adequacy of the containment. It was found that as a result of thermal expansion of the drywell shell against the concrete walls of the containment structure, the thermally induced loads for 340°F at 0.5 psig are the same as for the design condition of 281°F at zero psig. At 340°F and zero psig the loads are slightly greater and result in a slight decrease in safety factor from 2.2 to 1.9. Therefore, it was concluded that the containment structure (design temperature of 281°F) provides adequate safety margin for the maximum steam superheat temperature of 340°F.

6.2.1.3.2.2 Containment Long-Term Response to a Design Basis Accident (DBA)

The long-term DBA-LOCA analysis assumes that one CS pump and two LPCI pumps are operating before 600 seconds. At 600 seconds into the event, the operator is assumed to switch one LPCI operation to Containment Cooling operation, while activating one service water pump and then turning off one LPCI pump. The following are the key assumptions for the long-term DBA-LOCA containment response analysis performed to obtain peak pool temperature. This analysis is different from the long-term DBA-LOCA analysis for NPSH, regarding the assumptions affecting the containment pressure response. In this analysis, the operator is assumed to initiate pool cooling and containment initial conditions such as pressure and humidity are determined such that the pressure response is maximized. On the other hand, for the NPSH-related DBA-LOCA analysis, activation of containment sprays is assumed with containment initial conditions minimizing the pressure response. Key input values assumed for this long-term DBA-LOCA are given in Tables 6.2-3, 6.2-3a, and 6.2-3b.
Some of the key assumptions are:

1. The DBA-LOCA is an instantaneous double-ended guillotine break of the recirculation suction line at the reactor vessel nozzle safe-end to pipe weld. The effective break area is 4.261 ft^2.

2. The reactor is operating at 102% of rated power (i.e., 3016 MWt) with an initial reactor pressure of 1005 psig. Concurrent with occurrence of the break, reactor scram occurs.

3. The reactor core power includes fission energy, fuel stored energy, metal-water reaction energy and ANS 5.1 + 2σ decay heat.

4. The initial suppression pool water volume corresponds to the Low Water Level (LWL) to maximize the suppression pool temperature response.

5. Before 600 seconds, two LPCI pumps and one core spray pump are used for ECCS. After 600 seconds, only one core spray pump is used.

6. Only one Containment Cooling loop with one heat exchanger is available for containment cooling, starting at 10 minutes.

7. The Containment Cooling flow rate is 5000 gpm, and the Containment Cooling heat exchanger K-value is 262 Btu/sec-^{o}F.

8. The Containment Cooling service water temperature is at the maximum value of 98^{o}F to maximize the suppression pool temperature response.

9. Passive heat sinks in the drywell, wetwell airspace and suppression pool are conservatively neglected to maximize the suppression pool temperature. According to acceptable practices, the heat sinks are conservatively neglected for the DBA-LOCA, wile they are taken into account for other events, such as steam line breaks and IBA.

10. Condensate Storage Tank (CST) water inventory is not available for vessel makeup. The containment pressure and suppression pool temperature response for are plotted in Figures 6.2-19 and 6.2-20.

6.2.1.3.3 Containment Response to a DBA-LOCA for Minimum NPSH

The DBA-LOCA analysis for NPSH is performed for two time periods: short-term (up to 600 seconds) and long-term (after 600 seconds).

The following are the key assumptions for the short-term containment response to DBA-LOCA for minimum NPSH.

For the DBA-LOCA for short-term NPSH evaluation (600 seconds), the analysis is based on a single failure of the loop selection logic. Consequently, the flow from all four LPCI pumps goes into the broken recirculation loop and subsequently discharges into the drywell directly. The maximum runout flow rate is assumed. Both core spray pumps are operating with the maximum flow rate.

Minimum initial drywell and wetwell pressures and maximum initial drywell humidity are assumed. This minimizes the amount of non-condensable gas in the containment, which minimizes the pressure response. The initial suppression pool water volume corresponds to the Low Water Level (LWL) to maximize the suppression pool temperature response.

Key input values assumed for DBA-LOCA analysis for NPSH are given in Tables 6.2-3, 6.2-3a.

As a result of the large LPCI injection directly into the drywell during the first 10 minutes, a significant reduction in drywell pressure and temperature produced a reduction of pressure in the suppression chamber. Figure 6.2-19b shows the short-term containment pressure response for NPSH due to DBA-LOCA. Figure 6.2-20b shows the short-term containment suppression pool temperature response for NPSH due to DBA-LOCA.

The assumptions listed in Section 6.2.1.3.2.2, which are applicable for the long-term DBA-LOCA analysis for peak pool temperature, are used for the minimum NPSH analysis with the following exceptions:

1. Minimum initial drywell and wetwell pressures and maximum initial drywell humidity are assumed. This minimizes the amount of non-condensable gas in the containment, which minimizes the pressure response.

2. Containment cooling is achieved by operating one Containment Cooling loop at 600 seconds in the containment spray mode (drywell and wetwell sprays), instead of the pool cooling mode. This will minimize the containment pressure response, since cold water sprays will bring down the pressure.

3. The drywell and wetwell spray flow rates are 4750 gpm and 250 gpm, respectively. The total Containment Cooling heat exchanger K-value is 281.7 Btu/sec-°F.

4. The Containment Cooling service water temperature is at a maximum value of 95°F.

5. Passive heat sinks in the drywell and wetwell airspace are modeled to minimize the pressure response.

Figures 6.2-19c and 6.2-20c present the containment pressure and temperature response for the long-term DBA-LOCA for NPSH. It is noted that the early portion (before 600 seconds) of the plots for the long-term DBA-LOCA should not be used. For this time period, the short-term DBA-LOCA results should be used.

This page has been intentionally left blank.

This page has been intentionally left blank.

6.2.1.3.4 Mark I Program Description for Reevaluation of Containment Response to Hydrodynamic Loads

This subsection describes the analysis performed to resolve new loadings identified after the original design of the primary containment.[13]

The first generations of GE BWR nuclear steam supply systems are housed in a containment structure designated as the Mark I containment system. Dresden Units 2 and 3 utilize Mark I Containments.

The original design of the Mark I containment system considered postulated accident loads previously associated with containment design. These included pressure and temperature loads associated with a LOCA, seismic loads, dead weight loads, jet impingement loads, hydrostatic loads due to water in the suppression chamber, overload pressure test loads, and construction loads.

In the course of performing large-scale testing of an advanced design pressure-suppression containment (Mark III), and during in-plant testing of Mark I containments, new suppression pool hydrodynamic loads, which had not been explicitly included in the original Mark I containment design basis, were identified. These additional loads result from dynamic effects of drywell air and steam being rapidly forced into the suppression pool (torus) during a postulated LOCA and from suppression pool response to SRV operation generally associated with plant transient operating conditions. Since these hydrodynamic loads had not been explicitly considered in the original design of the Mark I containment, the NRC determined that a detailed reevaluation of the Mark I containment system was required.

To better understand the reasons for reevaluating the Mark I containment design, the historical development of the original Mark I containment design basis is presented here. The Mark I containment design was based on experimental information obtained from testing performed on a pressure-suppression concept for the Humboldt Bay Power Plant and from testing performed for the Bodega Bay Plant concept. The purpose of these initial tests, performed from 1958 through 1962, was to demonstrate the viability of the pressure-suppression concept for reactor containment design. The tests were designed to simulate LOCAs with breaks in piping sized up to approximately twice the cross-sectional break area of the design basis LOCA. The data from these tests were the primary experimental bases for the design of the Mark I containment system.

During the large-scale testing of the Mark III containment system design, in the period 1972 through 1974, new suppression pool hydrodynamic loads were identified for the postulated LOCAs. GE tested the Mark III containment concept in its Pressure Suppression Test Facility (PSTF). These tests were initiated for the Mark III concept because of configurational differences between the previous containment concepts and the Mark III design. More sophisticated instrumentation was available for the Mark III tests, as were computerized methods for data reduction. It was the PSTF testing that first identified the short-term dynamic effects of drywell air being forced into the suppression pool in the initial stage of the postulated LOCA. This air injection into the suppression pool water results in a pool swell event of short duration. In this event, a slug of water rises and impacts the underside of structural components within the suppression chamber.

In addition to the information obtained from the PSTF data, other LOCA-related dynamic load information was obtained from foreign testing programs for similar pressure-suppression containments. It was from these foreign tests that oscillatory condensation loads during the later stages of a postulated LOCA were identified.

Experience at operating plants indicated that SRV discharges to the suppression pool would cause oscillatory hydrodynamic loads on the suppression chamber. Both the LOCA and SRV discharges are characterized by an initial short-period injection of air, followed by a longer period of steam discharge, into the suppression pool.

Consequently, in February and April of 1975, the NRC transmitted letters to all utilities owning BWR facilities with the Mark I containment system design, requesting that the owners quantify the hydrodynamic loads and assess the effect of these loads on the containment structure. The February 1975 letters reflected NRC concerns about the dynamic loads from SRV discharges, while the April 1975 letters indicated the need to evaluate the containment response to the newly identified dynamic loads associated with a postulated design basis LOCA.

Recognizing that the additional evaluation effort would be very similar for all Mark I BWR plants, the affected utilities formed an "ad hoc" Mark I Owners Group. The objectives of the group were to determine the magnitude and significance of these dynamic loads as quickly as possible and to identify courses of action needed to resolve any outstanding safety concerns. The Mark I Owners Group divided this task into two programs: a short-term program (STP) to be completed in early 1977 and a long-term program (LTP) to be completed in 1979.

The STP objectives were to verify that each Mark I containment system would maintain its integrity and functional capability when subjected to the most probable loads induced by a postulated design basis LOCA, and to verify that licensed Mark I BWR facilities could continue to operate safely, without endangering the health and safety of the public while a methodical, comprehensive LTP was being conducted.

The STP structural acceptance criteria used to evaluate the design of the torus and related structures were based on providing adequate margins of safety (i.e., a safety-to-failure factor of 2), to justify continued operation of the plant before the more detailed results of the LTP were available.

A short-term program plant unique evaluation was performed for Dresden 2 & 3. The evaluation concluded that a sufficient margin of safety had been demonstrated to assure the functional performance of the containment system and, therefore, any undue risk to the health and safety of the public was precluded.

The basis for the NRC's conclusions relative to the STP are described in NUREG-0408. Subsequently, the NRC granted the operating Mark I facilities exemptions relating to the structural factor of safety requirements of 10 CFR 50.55(a). These exemptions were granted for an interim period of approximately 2 years, while the more comprehensive LTP was being conducted.

The LTP objectives were to establish design-basis (conservative) loads that are appropriate for the anticipated life of each Mark I BWR facility (40 years) and to restore the originally intended design-safety margins for each Mark I containment system.

The content of the LTP was documented in the Mark I Containment Program, Program Action Plan.[14] The principal thrust of the LTP was the development of generic methods for the definition of suppression pool hydrodynamic loading events and the associated structural assessment techniques for the Mark I configuration.

The generic aspects of the Mark I Owners Group LTP were completed with the submittal of the Mark I Containment Program Load Definition Report (LDR),[15] and the Mark I Containment Program Structural Acceptance Guide (PUAAG),[16] as well as supporting reports on the LTP experimental and analytical tasks.[17] The generic analysis techniques were used to perform a plant unique analysis to confirm the adequacy of the modifications made to the containment structures and related piping. This analysis was documented in the Plant Unique Analysis Report (PUAR),[7] which shows that the original margins of safety in the containment design have been restored.

6.2.1.3.4.1 Loss-of-Coolant-Accident-Related Hydrodynamic Loads

A postulated LOCA results in several dynamic loading conditions. The postulated sequence of events during the LOCA and the associated potential dynamic loading conditions are shown in Figure 6.2-21 and described below.

6.2.1.3.4.1.1 Pool Swell Phenomena

With the instantaneous rupture of a steam or recirculation line, a shock wave exits the broken primary system pipe and expands into the drywell atmosphere. At the break exit point, the wave amplitude theoretically is equal to reactor operating pressure (1000 psia); however, there would be rapid attenuation as the wave front expands spherically outward into the drywell. Further attenuation would occur as the wave enters the drywell vent system and progresses into the suppression pool.

Since there would be a very rapid drywell pressure increase associated with the postulated LOCA, a compression wave would propagate into the water initially standing in the downcomers. Before this water is cleared from the downcomers, this compression wave would propagate through the suppression pool and result in a dynamic loading on the suppression chamber (torus). The compression wave would also result in a dynamic loading condition on structures within the suppression pool.

Immediately following the postulated LOCA, the pressure and temperature of the drywell atmosphere would increase. Subsequently, pressure and temperature would also increase in the vent system and would lead to mechanical and thermal loadings on the vents, vent header, and downcomers.

With the drywell pressure increase, the water initially standing in the downcomers accelerates into the pool, and the downcomers clear of water. During this water-clearing process, a water jet forms in the suppression pool, and causes a potential water-jet impingement load on the structures within the suppression pool and on the torus section beneath the downcomers.

Immediately following downcomer clearing, a bubble of air starts to form at the exit of the downcomers. As the bubble forms, its pressure is nearly equal to the drywell pressure at the time of downcomer clearing. The bubble pressure is transmitted through the suppression pool water and results in a downward load on the torus.

When the air/steam flow from the drywell becomes established in the vent system, the initial bubble expands and, subsequently, decompresses as a result of overexpansion. During the early stages of this process, the pool will swell in bulk mode (i.e., a ligament of solid water is being accelerated upward by the air bubble). During this phase of pool swell, structures close to the pool surface experience impact loads as the rising pool surface strikes the lower surfaces of the structures. This is followed by drag loads as the pool surface continues to rise past the structures. In addition to these impact and drag loads above the pool, there will also be drag loads as the bubble formation causes water flow past submerged structures and equipment.

As the water slug continues to rise (pool swell), the bubble pressure falls below the torus airspace pressure. However the momentum of the water slug causes it to continue to rise. This compresses the air volume above the pool and results in a net upward pressure loading on the torus. The thickness of the water slug decreases as it rises. Aided by impact of the vent header, it will begin to break up and evolve into a two-phase "froth" of air and water. The froth will continue to rise as a result of its own momentum, and it will impinge on structures above the pool breakthrough elevation.

When the drywell airflow rate through the vent system decreases and the air/water mixture in the suppression pool experiences gravity-induced phase separation, the pool liquid upward movement stops and the "fallback" process starts. During this process, structures in the torus could be subjected to a pressure increase. Following "fallback," waves may develop on the suppression pool surface, thereby presenting a potential source of dynamic loads on the downcomers, torus, and any other structures close to the water surface.

The pool swell transient typically lasts on the order of 3 to 5 seconds. Because of the configuration of the drywell and the volume of the vent system, this period is dominated by the flow of the drywell atmosphere through the vent system. Steam flow will follow, beginning near the end of the pool swell transient, with a relatively high concentration of noncondensible gas. Throughout these periods, there is a significant pressure differential between the drywell and the torus. This, together with flow-induced reaction forces, leads to structural loads on the vent system.

It should be noted that the Dresden containment is inerted with nitrogen. However, pool swell experimental studies conducted for the LTP used air as the flowing medium, because of its availability and the thermalhydraulic similarities of air and nitrogen. Accordingly, the terms drywell atmosphere and drywell air are often used interchangeably.

6.2.1.3.4.1.2 Loss-of-Coolant-Accident Steam Condensation Phenomena

As the flow of steam through the vent system continues, pressure oscillations will occur in the vent system and in the suppression pool. Experimental data suggest that the amplitude and frequency of these pressure oscillations are primarily functions of the mass flowrate through the vent system, the concentration of noncondensibles in the mass flow, the downcomer submergence, and the suppression pool temperature. The pressure oscillations will cause loadings on the vent system, the torus shell, and the structures submerged in the pool.

Early in the transient, when the mass flow is relatively high, the pressure oscillations appear as a sinusoidal function with an amplitude varying with time. These oscillations are referred to as "condensation oscillations (COs)."

When the mass flowrate through the vent system decreases, the pool will begin to reenter the downcomers intermittently. This period, termed "chugging (CH)," is characterized by fairly irregular pressure pulses.

The ECCS is designed so that shortly after a postulated LOCA, LPCI will automatically start to pump water from the suppression pool into the reactor pressure vessel. This water floods the reactor core and, subsequently, cascades into the drywell through the postulated break. The time at which this will occur depends upon break size and location. Since the drywell will be full of steam when the vessel floods, the sudden introduction of water causes steam condensation and drywell depressurization. As the drywell pressure falls below the torus pressure, the vacuum relief system allows noncondensibles from the suppression chamber to be drawn into the drywell. Eventually, enough noncondensibles will return to equalize the drywell and torus pressures; however, during this drywell depressurization transient, there will be a period of negative pressure on the vent system within the torus volume. When the mass flow from the break is small, the pressure oscillations will essentially be terminated.

Following vessel flooding, suppression pool water is continuously recirculated through the core by the LPCI pumps. The energy associated with the core decay heat will result in a slow suppression pool heatup. Operators will initiate suppression pool cooling to control suppression pool temperature. After several hours, the containment cooling heat exchangers will terminate the increase in the suppression pool temperature. Refer to Section 6.2.1.3.3 for the containment long-term response to a DBA. An increase in the pressure in the drywell and torus is associated with this post-LOCA suppression pool temperature increase; however, the resultant maximum pressure will not exceed that which occurs during the short-term blowdown phase of the accident.

6.2.1.3.4.2 Safety-Relief Valve Discharge-Related Hydrodynamic Loads

Safety-relief valve discharge phenomena is the other primary Mark I loading. Dresden is equipped with relief valves (called safety-relief valves or SRVs in this discussion) to control primary system pressure transients. The SRVs are described in Section 5.2.2. When an SRV is actuated, steam released from the primary system will be discharged into the suppression pool where it will condense.

Upon actuation of an SRV, the noncondensible gas volume within the partially submerged SRV discharge line is compressed by the high-pressure steam and accelerates the water leg into the suppression pool. The water jets thus formed create pressure and velocity transients which cause drag or jet impingement loads on submerged structures.

Following water clearing, the compressed gas is accelerated into the suppression pool and forms a high-pressure gas bubble. This bubble expands and contracts a number of times before it rises to the suppression pool surface. The associated transients again create drag loads on submerged structures, as well as pressure loads on the submerged boundaries. These loads are referred to as SRV air-clearing loads.

Following the gas-clearing phase, essentially pure steam is injected into the pool. Experiments indicate that the steam jet/water interface which exists at the discharge line exit is relatively stationary, as long as the local pool temperature is low. Thus, condensation proceeds in a stable manner, and no significant loads are experienced. Continued steam blowdown into the pool will increase the local pool temperature. The condensation rates at the turbulent steam/water interface are eventually reduced to levels below those needed to readily condense the discharge steam. At this threshold level, the condensation process becomes unstable; i.e., steam bubbles are formed and shed from the pipe exit, and the bubbles oscillate and collapse. This results in severe pressure oscillations, which are imposed on the pool boundaries. To preclude unstable condensation, limits have been established for the allowable suppression pool temperature as discussed in Section 6.2.1.3.6.4.

6.2.1.3.5 Hydrodynamic Loads Evaluated

The hydrodynamic loads evaluated include a range of analyses to determine the effects of a LOCA from the instant of postulated pipe break to the final stages of blowdown and long-term heatup of the suppression pool. See Figure 6.2-21. Additional analyses were performed to evaluate the effects of SRV loadings.

The PUA was required to address only those phenomena or combinations of phenomena which involve suppression pool hydrodynamic loads. This evaluation included certain loads in the combinations of phenomena which were previously analyzed and justified in the original Final Safety Analysis Report (FSAR). However, these loads are included in the PUA because improved analysis techniques have evolved since the original design was justified. Unless otherwise specified, any loading condition or structural analysis technique not addressed by the PUA will be in accordance with the original design evaluation.

6.2.1.3.5.1 Design Basis Accident

The DBA for the Mark I containment design is the instantaneous guillotine rupture of the largest pipe in the primary system (the recirculation suction line). This LOCA leads to a specific combination of dynamic, quasi-static, and static loads in time. Figures 6.2-22, 6.2-23, and 6.2-24 show the load combinations for the DBA. The assumption of combining an SRV discharge with the DBA is beyond the design basis of Dresden Unit 2 and 3. However, the DBA does not represent the limiting case for all structural elements. Consequently, a spectrum of postulated pipe breaks was evaluated to determine the worst loading condition for each structural element. For the LTP an intermediate break accident (IBA) and a small break accident (SBA) were specified in addition to the DBA.

The IBA is a 0.1 square foot, instantaneous, liquid line break in the primary system. This break size will not result in rapid reactor depressurization and, consequently, will not result in significant pool swell loads. However, this break size is large enough that the HPCI system cannot maintain the reactor vessel water level. Therefore, this LOCA will result in a combination of condensation loads and multiple SRV discharge loads. Figure 6.2-25 shows the loading conditions for the IBA.

The SBA is a 0.01 square foot, instantaneous, steam line break in the primary system. The fluid loss rate for this break size is small enough so that HPCI operation can maintain the reactor vessel water level. However, this size break will not result in rapid reactor depressurization. Therefore, this LOCA will result in a long-duration combination (relative to the DBA and IBA) of chugging and multiple SRV discharge loads. Figure 6.2-26 shows the loading conditions for the SBA.

The duration of the SBA condensation loads proposed by the Mark I Owners Group is assumed to be terminated by manual actuation of the automatic depressurization system (ADS) 10 minutes after the postulated pipe break.

Not all of the suppression pool hydrodynamic loads can occur at the same time. In addition, the load magnitudes and timing will vary, depending on the accident scenario under consideration. Therefore, combinations of loading conditions have been determined from typical plant primary system and containment response analyses, with considerations for automatic actuation, manual actuation, and single active failures of the various systems in each event.

6.2.1.3.5.2 Loss-of-Coolant-Accident Transient Loads

Loss-of-coolant transient loads are specified in the Plant Unique Load Definition (PULD).[8] The following loads are specified:

A. Pressure and temperature time histories for the suppression chamber and drywell;

B. Vent system pressurization and thrust loads;

C. Net vertical pool swell loads and average submerged pressures on the suppression chamber;

D. Pool swell impact and drag loads on the vent system; and

E. Vent header deflector loads.

These transient loads were developed from plant unique testing[18] and/or analysis using Dresden specific plant conditions which were provided in the Containment Data Specifications.[19]

6.2.1.3.5.2.1 Pressure and Temperature Time Histories

The pressure and temperature time histories for the drywell and suppression chamber due to a LOCA were calculated by the GE Pressure-Suppression Containment Analytical Model.[20] This analytical model calculates the thermodynamic response of the drywell, vent system, and suppression chamber (wetwell) volumes to the mass and energy released from the primary system following a postulated LOCA. The PULD provides time histories for the DBA, IBA, and SBA case, for both the operating and zero drywell-wetwell differential pressure (ΔP). For the SBA, a load condition assuming a single SRV actuation and a maximum pool temperature of 168°F was evaluated. This temperature is 3°F higher than that reported in the PULD.[21] While the Mark I design basis for Dresden requires a drywell to torus ΔP of 1.0 psi, the PUAAG requires consideration of a special load case assuming the loss of ΔP.

6.2.1.3.5.2.2 Vent System Pressurization and Thrust Loads

Vent system pressurization and thrust loads occur in the vent system (main vent, vent header, and downcomers) following a LOCA because of pressure imbalances between the increasing pressure in the vent system and in the surrounding torus airspace and because of forces resulting from changes in linear momentum. The load definition was derived from the pressure and flow transients calculated by the GE containment response analysis. These loads were calculated for only the DBA, which provides a more rapid pressurization rate and higher mass flowrate than either the IBA or SBA. Horizontal and vertical force components were calculated at each location of a change in flow direction and are documented in the PULD.

6.2.1.3.5.2.3 Torus Pool-Swell Pressure Loads

Torus pool-swell pressure loads occur as a result of a postulated design basis LOCA. From the testing done during the STP, the pool swell loads have been shown to be sensitive to various plant parameters, such as downcomer submergence and drywell-to-torus differential pressure. Consequently, the Mark I Owners Group devised a testing program for the LTP whereby the pool swell loads could be assessed on a plant-specific basis. The Quarter-Scale Test Facility (QSTF) was used for this analysis.[18] The data obtained from the QSTF plant-unique tests served as the principal source for the pool-swell load definitions in the PULD.

6.2.1.3.5.2.4 Pool-Swell Impact and Drag Loads

Pool-swell impact and drag loads are a consequence of pool swell. As the suppression pool surface rises, structures or components located above the pool (but lower than the maximum elevation of the pool surface achieved during pool swell) will be subjected to water impact-loads followed by a drag load until the upward motion of the pool stops. The principal structures which experience impact and drag loads during pool swell in a Mark I containment system are the vent system, the vent header deflector, and miscellaneous structural elements (e.g., pipes and catwalk). In general, the load definition techniques proposed in the Load Definition Report (LDR) are based on data from the QSTF plant-specific test series. The specific load definition techniques for each of the principal structural groups described above are presented in the evaluations below.

The impact and drag loading transient consists of an initial impact spike, which is caused by water striking and wetting the lower surface of the structure, followed by a transition to a drag force, which is composed of a "steady-flow drag" component and an "unsteady-flow drag" component. The latter is a result of the acceleration or deceleration of the flow field around the structure. The specific loading transient is a function of the geometry of the affected structure and the velocity and curvature of the pool surface at the time of impact.

6.2.1.3.5.2.5 Pool Swell Froth Impingement Loads

Pool-swell froth impingement loads occur on certain structures (e.g., torus walls, piping, and spray header) located above the pool surface.

Froth is a gas/water mixture which rises above the pool surface and may impinge on the torus walls and structures within the torus airspace. Subsequently, when the froth falls back, it creates froth-fallback loads. There are two mechanisms by which froth may be generated:

A. As the rising pool strikes the bottom of the vent header and/or the vent header deflector, a froth spray is formed, which travels upward and to both sides of the vent header.

B. A portion of the water above the expanding gas bubble becomes detached from the bulk pool; this water is influenced by only its own inertia and gravity. The bubble breakthrough creates a froth which rises into the airspace beyond the maximum bulk pool swell height.

The LDR provides the load definition for both of these conditions. For froth fallback, the LDR assumes a fallback velocity based on freefall of the froth from the upper surface of the torus shell directly above the target structure.

6.2.1.3.5.2.6 Pool Fallback Loads

Pool fallback loads are defined in the LDR and apply to structures within the torus (although not the torus itself) that are below the upper surface of the pool at its maximum height. Following the pool-swell transient, the pool water falls back to its original level and, in the process, generates fallback loads. After the pool surface has reached its maximum height as a result of pool swell, it falls back under the influence of gravity and creates drag loads on structures inside the torus shell. These structures are between the maximum bulk pool swell height and the downcomer exit level, or they may be immersed in an air bubble extending beneath the downcomer exit level. The fallback load starts as soon as the pool reaches its maximum height; it ends when the pool surface falls past the structure of concern or the pool velocity reaches zero.

The assumption in the LDR that fallback loads on structures below the downcomer exit level are negligible is reasonable, except for structures which come within the bubble boundaries. Structures that may be enveloped by the LOCA bubble were evaluated for potential fallback loads as a result of bubble collapse to ensure that such loads are not larger than the LOCA bubble-drag loads described later.

6.2.1.3.5.2.7 Condensation Oscillation Loads and Chugging Loads

Condensation oscillation (CO) loads and chugging (CH) loads refer to the oscillatory pressure loads imparted to structures as a result of the unsteady, transient behavior of the condensation of the steam (released during a LOCA) occurring near the end of the downcomers. Condensation oscillations occur at relatively high vent flowrates and are characterized by continuous periodic oscillations, with neighboring downcomers oscillating in phase. Chugging occurs at lower vent flowrates and is characterized by a series of pulses typically a second or more apart.

The condensation phenomenon involves an unsteady, turbulent, two-phase flow. No reliable analytical methods exist to model such flows. Furthermore, because of the apparently random element in the condensation phenomena, no relative and proven empirical engineering methods exist which would allow accurate assessment of either the load magnitudes, the parametric variation of the loads, or the scaling of the loads. Consequently, CO and CH load definition must rely on a database taken from experiments which model, as closely as possible, the conditions in an actual plant. For this reason, CO and CH loads are based on the results of tests conducted in the Full-Scale Test Facility (FSTF), which was a full-scale, 22.5° sector of a typical Mark I torus connected to simulated drywell and pressure vessel volumes.[22]

The principal design parameters for the FSTF (e.g., vent-area-to-pool-area ratio and distance of the downcomer exit to the torus shell) were selected to produce conservative data from which the loads could be derived. Structurally, the FSTF torus sector was an exact replica of the Monticello plant. (Monticello is considered to be structurally "average" in relation to the range of the Mark I design characteristics.)

The CO and CH torus shell pressure loads, downcomer lateral loads, and vent system pressure loads were defined from the FSTF data.

6.2.1.3.5.2.8 Fluid Structure Interaction

Fluid structure interaction (FSI) affects the CO and CH loads transmitted to the structure by the water in the pool. To assess the FSI effect, the Mark I Owners Group developed a coupled fluid-structure analytical model simulating the FSTF structure and suppression pool.[23]

The concern regarding FSI effects relates to the applicability of the database obtained from the Monticello in-plant tests to plants with differing FSI characteristics.

Fluid structure interaction is an effect caused by the motion of the torus shell (boundary) relative to the oscillatory pressure source that drives that motion. The motion of the torus shell will change the pressure measured on the torus shell and, if the motion is strong enough, will feed back to affect the source pressure as well.

Analytical studies have demonstrated that increased wall flexibility will tend to reduce the measured shell pressure for dynamic loads with higher frequencies than the structural natural frequency. The Monticello SRV discharge tests indicated that the measured bubble pressure frequency was less than the predominant shell response frequency. Therefore, it was concluded that there was no significant reduction in the shell pressures in the Monticello data as a result of FSI.

6.2.1.3.5.3 Safety-Relief Valve Discharge Loads

Safety-Relief Valve Discharge Loads include the safety-relief valve discharge line (SRVDL) transient, and SRV gas-clearing torus pressure loads. These loads are defined in the LDR and Application Guides.[24] The SRVDL loads are based on an analytical model derived from first principles.[25] The SRV torus pressure loads are based on four key elements:

A. An in-plant test series (Monticello) from which load levels at one representative set of plant conditions were determined;

B. A semi-empirical analytical model to be used for extrapolation of other plant conditions;

C. Subscale tests from which trends were derived; and

D. A scaling analysis which demonstrated the applicability of the results of the subscale tests (above).

The load methodologies were further refined by NRC criteria in NUREG-0661 and by an in-plant test at Dresden.

Safety-relief valve loads are defined for the following load cases:

A. First actuation;

B. First actuation, leaking SRV; and

C. Subsequent actuation.

The first case can occur for any one valve, for the ADS valves, or for multiple valves. The second and third cases can occur for one or more valves, as determined by plant unique analysis.

The spatial distributions and pressure attenuations are defined for each torus bay, noting that only 5 of the 16 torus bays (or segments) contain T-quenchers. Safety-relief valve bubble frequencies were "tuned" to the dominant torus structural frequency to produce conservative resonance conditions.

The suppression pool temperature response to various combinations of SRV actuations was also evaluated to determine the result of vibratory pressure loads at elevated pool temperatures. Refer to Section 6.2.1.3.6.4.3 for a description of the events evaluated.

6.2.1.3.5.4 Submerged Structure Drag Loads

Submerged structure drag loads can occur due to LOCA and SRV conditions. The expulsion of water, gas, and, subsequently, steam following a postulated LOCA or an SRV actuation induces a flow velocity and acceleration field within the suppression pool. Structures either initially submerged within the pool or sufficiently close to the pool surface will experience loads as a result of this induced pool motion. These loads can be conveniently divided into three major chronological phases. Water-jet loads arise from the expulsion of the water slug which is initially within the downcomer of SRV discharge line. Bubble-drag loads arise from the induced pool motion created by the expulsion of the gas from the drywell through the vent system or from the SRV discharge line. Condensation and chugging loads arise from the unsteady condensation process that occurs during certain time segments of a postulated LOCA. Unsteady condensation is not considered for the SRV quencher device, because the device is designed to avoid such unsteady phenomena within its operating range.

6.2.1.3.5.5 Secondary Loads and Other Considerations

The following secondary loads and other considerations were also examined in the Mark I Program:

A. Seismic slosh, which occurs due to horizontal seismic motion on the pool;

B. Post-pool-swell waves, due to the wave action associated with continued flow through the downcomers;

C. Asymmetric vent system flow, resulting from asymmetric flowrates due to vent blockage;

D. Downcomer gas-clearing loads, resulting from the rapid clearing of gas from the vent system causing lateral loads as bubbles are being formed in the pool;

E. Sonic and compression wave loads, due to the shock wave propagating from the break location; and

F. Safety-relief valve steam discharge loads.

Based on various tests and/or evaluations, the secondary loads identified above have all been shown to be insignificant and, therefore, neglected in the PUA. Downcomer submergence and pool thermal stratification were shown to be of no concern for a minimum initial downcomer submergence of 3 feet.

6.2.1.3.6 Mark I Program Approach and Results

6.2.1.3.6.1 Structural and Mechanical Elements Analyzed

Since most of the BWR Mark I facilities were designed and constructed at different times, there are variations in the codes and standards to which they were constructed and subsequently licensed. For the reassessment of the suppression pool hydrodynamic loads, the criteria developed provides a consistent and uniform basis for acceptability. In this evaluation, references to "original design criteria" mean those specific criteria approved during the operating license review of the FSAR.

The structural and mechanical elements that were reassessed in the LTP plant-unique analyses include the following:

A. Pressure Suppression System

1. The torus shell with associated penetrations, reinforcing rings, and support attachments;

2. The torus supports to the building structure;

3. The vents between the drywell and the vent header, including penetrations therein;

4. The local region of the drywell at the vent penetration;

5. The bellows between the vents and the torus shell, internal or external to the torus;

6. The vent header and attached downcomers;

7. The vent header supports to the torus shell; and

8. Vacuum-breaker piping system, including vacuum-breaker valves, attached to torus shell penetrations and to vent penetrations external to the torus.

B. Attached Piping Systems

1. Piping systems, including pumps and valves, internal to the torus, attached to the torus shell, and/or vent penetrations;

2. All SRV discharge piping;

3. Applicable portions of active containment system piping, such as ECCS suction piping and other piping systems required to maintain core cooling after a LOCA;

4. Applicable portions of the piping systems which provide the drywell-torus differential pressure control;

5. Applicable portions of other affected piping systems, including vent drains; and

6. Supports for all such piping systems.

C. Internal Structures

1. Internal structural elements such as catwalks and their supports. Although these elements are not operative in the performance of the containment function, it is important that their failure does not impair that function and

2. Vent-header deflectors and associated hardware.

For the purpose of performing the plant unique analysis and designing modifications, the structures described above have been categorized in accordance with their functions in order to assign the appropriate service limits. The general components of a Mark I suppression chamber have been classified in accordance with the ASME B&PV Code in the following manner:

A. The pressure-retaining elements of the suppression chamber system and associated supports are classified in accordance with the ASME B&PV Code criteria for Class MC vessels and Class MC supports.

B. Piping systems are classified as Class 2 or Class 3 for ASME Code evaluation. In addition, for each event combination, piping systems are categorized as either essential or nonessential. Essential piping systems have the additional requirements for operability of active components.

A piping system, or a portion thereof, is considered essential if, during or following the event combination being considered, the system is necessary to ensure:

1. The integrity of the reactor coolant pressure boundary;

2. The capability to shutdown the reactor and maintain it in a safe-shutdown condition; or

3. The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposure comparable to the guideline exposures of 10 CFR 100 or 10CFR 50.67 as applicable.

In addition, essential piping may become nonessential piping in a later portion of an event combination if the piping is no longer required to perform a safety function during the event combination being considered or during any subsequent event combination. In all cases, piping shall be considered to be essential if it performs a safety function at a later time during the event combination being considered or during any subsequent event combination.

A pump or valve in an essential piping system is considered an active component if it is required to perform a mechanical motion during the course of accomplishing a system-safety function. Other pumps and valves are inactive components.

C. Internal structures, such as ladders, catwalks, and vent-header deflectors, are nonsafety-related elements because they do not perform a pressure-retaining function. As such, with the exception of attachment welds to ASME Code structures, these elements are not covered by the ASME Code criteria. These attachment welds are classified in accordance with the ASME Code requirements for the structure to which they are attached.

6.2.1.3.6.2 Acceptance Criteria

The structural acceptance criteria set forth in the PUAAG generally are contained in Section III of the ASME B&PV Code through the Summer 1977 Addenda. These criteria were used in the LTP plant-unique analyses to evaluate the acceptability of the existing Mark I containment designs or to provide the basis for any plant modification necessary to withstand the suppression pool hydrodynamic loading conditions. The application of the stress limits associated with these criteria provides adequate safety margin to ensure the containment structural integrity for all anticipated loading combinations and ensures that the containment and attached piping systems will perform their intended functions during those loading conditions expected to occur as a result of a LOCA or SRV discharge.

In addition to Service Levels A, B, C and D, as specified in the ASME Code, special, non-ASME Code limits are associated with Level E and are applicable only to nonsafety-related structural elements where element failure may be acceptable, if such failure does not result in significant damage to safety-related items. For this purpose, failure shall be considered to occur at any point at which the Level D Service Limit is exceeded. Therefore, demonstrating that Level D Service Limits are satisfied shall be an objective. When this cannot be done and the limit is exceeded at any one point on the element, the analysis must continue with a break at that point on the element, and the consequences evaluated. If the limit is exceeded at another point, the structure between the two points shall be considered to be unrestrained and the consequences must be considered in evaluation of other elements to their respective limits.

The Applicable ASME Code Sections and the associated addenda are defined in the PUAAG and were satisfied for the long-term program PUA.

In addition to ASME Code requirements, operability and functionality requirements are imposed. Operability is defined as the ability of an active component to perform the required mechanical motion. Functionality is defined as the ability of piping system to pass rated flow.

In the criteria established by the Mark I Owners Group, active components are considered operable if Level A or B Service Limits are met unless the original component design criteria establish more conservative limits. If the original component design criteria establish more conservative limits, conformance with these more conservative limits shall be demonstrated, even if Level A or B Service Limits are met. If the original component design criteria are silent with respect to operability limits, satisfaction of Level A or B Service Limits is sufficient to demonstrate operability.

Active components which do not satisfy Level A or B Service Limits, and, therefore, satisfy either Level C or D Service Limits, require demonstration of operability. If original component design criteria for operability exist, conformance with those criteria shall be demonstrated. If the original component design criteria are silent with respect to operability limits, operability limits shall be established, and conformance with those criteria shall be demonstrated.

The operability requirements are necessary to ensure that the active safety-related components will be able to perform their intended functions. The concern is that loads which are calculated by elastic analysis and which produce stresses in excess of the material yield stress can produce excessive deformation in a component and, therefore, can cause interference of mechanical motion.

It is recognized that the designation of Level A and B Service Limits does not, by itself, guarantee the operability of active components. However, the scope of the Mark I containment long-term program is directed toward the effects of the incremental load increase as a result of the definition of suppression pool hydrodynamic loads and toward the restoration of the originally intended design-safety margins. The criteria for operability specify that the original component design criteria must be met where they are more conservative than the Level A and B Service Limits. Therefore, these operability criteria are sufficient to accomplish the objectives of the program.

Functionality of piping components is to be addressed in a manner consistent with the original design criteria.

Based on the dynamic nature of the Mark I loadings considered in the PUA and the type of material and support of the attached piping systems, the service level assignments for Class 2 and 3 piping are considered adequate for the prevention of significant flow reduction in the attached piping.

The general structural analysis techniques established by the Mark I Owners Group were performed with sufficient detail to account for all significant structural response modes, consistent with the methods used to develop the loading functions defined in the LDR. For those loads considered in the original design but not redefined by the LDR, either the results of the original analysis were used or a new analysis was performed, based on the methods employed in the original plant design. This general approach is consistent with the objectives of the program.

The damping values used in the analysis of dynamic loading events will be those specified in Regulatory Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants." Since these values are specified for seismic analysis of structures and components for operating basis earthquake (OBE) and safe shutdown earthquake (SSE) conditions, the values used will be consistent with the stresses expected under hydrodynamic loading conditions.

6.2.1.3.6.3 Criteria for Combination of Structural Responses

Criteria for combination of structural responses for nonpiping components were established by the Mark I Owners Group. The structural responses resulting from two dynamic phenomena were combined by the absolute sum method. Time phasing of the two responses were such that the combined state of the stress results in the maximum stress intensity. However, as an alternative, the cumulative distribution function (CDF) method could be used if the absolute sum does not satisfy the structural acceptance criteria. The CDF combined stress intensity value, corresponding to a nonexceedance probability of 84%, would be used to compute a reduction factor; this factor would then be applied to the stress intensity computed by the absolute sum method. An 84% probability of nonexceedance corresponds to a mean-plus-one standard deviation for two dynamic responses.

The CDF technique was applied on a component-specific basis and, therefore, reflects the nature of each component's response to two dynamic events. In the

Mark I evaluation, the CDF technique was not applied to more than two dynamic events occurring at any point in time.

For Mark I torus-attached piping systems, the use of the square-root-of-the-sum-of-the-squares (SRSS) method has been accepted.

6.2.1.3.6.4 Mark I Program Plant Unique Analysis Results

To reestablish the original plant design safety margins, various modifications to the containment system, SRVs, and torus attached piping were required. Table 6.2-4 lists the modifications made as a result of the Mark I Program.

The plant unique analysis was performed and documented in the PUAR.[7] The PUAR establishes that all applicable Mark I criteria have been met. The NRC staff performed a post-implementation audit review of the PUAR and concluded that the PUAR verified that the containment modifications have restored the original design margin to the primary containment.[26]

Results of the analyses conducted as part of the Mark I Program are summarized in Section 6.2.1.3.6.4.1 through 6.2.1.3.6.4.3.

6.2.1.3.6.4.1 Containment Differential Pressure Control

As a result of the Mark I Containment short-term program, a differential pressure control (ΔP) system was installed to enhance the containment safety margins due to pool-swell related loads. The system's purpose is to reduce the length of the water leg inside the vent system downcomers. In the event of a LOCA, downcomer clearing and subsequent bubble formation will occur sooner and at a lower driving (i.e., drywell) pressure, thereby reducing the pressure exerted on the torus shell. This is accomplished by maintaining drywell pressure greater than suppression chamber pressure during normal operation.

For the LTP, the Mark I Owners Group proposed the continued use of differential pressure control as one load mitigation technique which could be used to restore the intended margins of safety in the containment design. However, because this technique is an operational feature (i.e., the differential pressure must be maintained and controlled and could be lost during plant operation), the NRC determined that certain restrictions would have to be imposed for differential pressure control to be considered acceptable for long-term application.

The length of the water leg inside the downcomer is limited by the downcomer submergence. Consequently, the drywell-to-torus differential pressure and the resulting pool-swell load mitigation effects are also limited. In addition, in the design assessment for the differential pressure control system,[27] the Mark I Owners Group concluded that the probability of the occurrence of a large-break LOCA when the differential pressure is reduced or the system is out of service (for reasons described below), is less than 10^{-7} per reactor-year. However, the PUAAG and NUREG-0661 required that an additional structural assessment be performed to demonstrate that the containment can maintain its functional capability when the differential pressure control is out of service.

Figures 6.2-27 and 6.2-28 show the resulting pressure-time history at selected locations on the torus shell for the situation when the operating differential pressure between the drywell and torus is 1 psid. These results are based on plant unique QSTF test data and include the effects of the generic spatial distribution factors as well as the conservatism factors on the peak upward and downward loads. Pool-swell torus shell loads consist of a quasi-static internal pressure component and a dynamic pressure component and include the effects of the DBA internal pressure.

At zero ΔP between the drywell and torus, the pool-swell phenomena are the same as for the operating ΔP case. Figures 6.2-29 and 6.2-30 show the resulting pressure-time history. These results were calculated on the same basis as the operating ΔP results.

Although the existence of a differential pressure between the drywell and torus is safety related, the system used to develop the differential pressure need not be designed to engineered safeguards criteria because it does not perform a post-accident function. The design requirements established for the differential pressure control system ensure that the system will not increase either the probability or the consequences of an accident.

There are certain periods during normal plant operation when the differential pressure control cannot be maintained. Therefore, limiting conditions for operation (LCOs) have been established in the Technical Specifications of the license to ensure that these periods are minimized.

6.2.1.3.6.4.2 Loss-of-Coolant-Accident Load Analysis Results

As a result of the Mark I Program, peak pressure and temperature loads on the containment structure were reevaluated for various SBA, IBA and DBA scenarios. Basic assumptions used for this reanalysis are listed in Table 6.2-5. These analyses accounted for a downcomer submergence of 4 feet, drywell-to-torus differential pressure (see Section 6.2.1.3.6.4.1), and a revised torus airspace free volume. Results of these calculations are shown graphically in Figures 6.2-31 through 6.2-38.

As previously noted in Section 6.2.1.3.1, the torus airspace free volume assumed for the Mark I Program containment peak pressure and temperature reanalysis (listed in Table 6.2-5) was incorrect. To verify that the results of the Mark I Program are valid, an evaluation of the effect that the revised torus air and water volumes have on the peak containment pressure and temperature was conducted. It was found that the slightly smaller torus air volume both reduces the initial torus air mass and reduces the final volume for the total initial containment air mass after drywell air carryover. The larger initial torus water mass has only approximately a 1°F effect on peak pool temperature. These effects result in a calculated increase in peak torus pressure of about 0.6 psi. For the IBA and SBA the peak drywell pressure increases by an equal amount. For the DBA, the increase in containment pressure increases the density of the vent flow which reduces the vent system pressure drop. This partially offsets the torus pressure increase and results in only a 0.3 psi increase in the peak drywell pressure.

6.2.1.3.6.4.3 Safety Relief Valve Discharge Device Limitations

Dresden Station is equipped with safety/relief valves (SRVs) to protect the reactor from overpressurization during operating transients. When the SRVs open, steam released from the reactor vessel is routed through SRV discharge lines to the suppression pool where it is condensed. Extended steam blowdown into the suppression pool, however, can create temperature conditions near the discharge location that can lead to instability of the condensation process. These instabilities can, in turn, lead to severe vibratory loading on containment structures. This effect is termed condensation oscillation. This is mitigated at Dresden Station by the usage of quenchers at the end of the SRV discharge lines, as well as restrictions on the allowable bulk suppression pool water temperature, in order to ensure that the local pool temperature stays within acceptable ranges. Technical Specifications provides limiting conditions for operation and action requirements, regarding the suppression chamber temperature.

By letter dated March 21, 1995, the BWR Owners' Group (BWROG) requested the NRC staff review and approve GE report, NEDO-30832 entitled, "Elimination of Limit on BWR Suppression Pool Temperature." NEDO-30832 presented a discussion of test data and analysis that supports deletion of the requirement to maintain the local suppression pool temperature 20°F below the saturation temperature of the pool during SRV discharge.

Some Dresden quenchers and ECCS suction strainers are located in the same bay of the suppression chamber torus. For this limiting geometric configuration, an evaluation (references 73 and 72) has shown that steam flow from the quenchers would not be entrained into the ECCS suction. Therefore, a local pool temperature limit is not applicable.

6.2.1.3.7 Containment Capability

6.2.1.3.7.1 Potential For Hydrogen Generation

If, as a result of a severe accident, Zircaloy in the reactor core was to be heated above about 2000°F in the presence of steam, an exothermic chemical reaction would occur in which zirconium oxide and hydrogen would be formed. The corresponding energy release of about 2800 Btu per pound of zirconium reacted, would be absorbed in the suppression pool. The hydrogen formed, however, would result in an increased pressure due simply to the added moles of gas in the fixed volume. Although very small quantities of hydrogen would be produced during a DBA, the containment has the inherent ability to accommodate much larger amounts.

The Dresden containment is normally provided with an inerted atmosphere to preclude the possibility of a hydrogen combustion event within the containment. The oxygen deficient atmosphere assures that hydrogen build-up due to metal-water reaction is not a concern.

The generation of significant quantities of hydrogen due to a metal-water reaction from high fuel cladding temperatures is prevented by assurance of adequate core cooling. During normal operation, there are several systems, including feedwater and control rod drive (CRD), which add water directly to the reactor pressure vessel. A reliable, automatic means of cooling the core is provided by ECCS. This system is designed to provide adequate cooling in accordance with 10 CFR 50.46 limits assuming any single failure in addition to loss of offsite power. Refer to Section 6.3 for an evaluation of the ECCS performance.

Following a postulated LOCA, both oxygen and hydrogen may be produced by the radiolytic decomposition of primary coolant and suppression pool water. Decomposition would occur due to the absorption of gamma and beta energy released by fission products into reactor coolant and suppression pool water. Radiolysis is the only significant reaction mechanism whereby oxygen, the limiting combustion reactant, is produced within the containment. Therefore, radiolysis is the primary focus relative to combustible gas control for containments with inerted atmospheres. Refer to Section 6.2.5 for a description of the post LOCA combustible gas control system.

Several analyses and experiments have been conducted to quantify the post LOCA resultant hydrogen concentration in containment. Both inerted and noninerted containment atmospheres were evaluated covering both short term and long term hydrogen generation. These analyses are documented in References 30, 31, 32, and 33 and form the basis for the quantitative parameter values used in the containment capability calculations described below. For reference purposes a 0.1% metal-water reaction is equivalent to about three pound-moles and would result in a hydrogen volumetric concentration of approximately 0.4% in the primary containment. Metal-water reactions in excess of approximately 1% would result in a flammable mixture of hydrogen in air of 4% by volume.

6.2.1.3.7.2 Capability Calculation

As an index of the containment's ability to tolerate postulated metal-water reactions the concept of "containment capability" is used. Since this capability depends on the time domain, the duration over which the metal-water reaction is postulated to occur is one of the parameters used.

In this sense capability is defined as the maximum percent of fuel channels and fuel cladding material which can enter into a metal-water reaction during a specified duration without the design pressure of the containment structure being exceeded. To evaluate the containment system design capability, various percentages of metal-water reaction were arbitrarily assumed to take place over various durations of time. In this way the containment system capability can be determined without requiring prediction of the detailed events in a particular accident condition.

The basic approach to evaluating the capability of a containment with a particular containment spray design is to assume that the energy and gas are liberated from the reactor vessel over an arbitrary time period. The rate of energy release over the entire duration of the release is arbitrarily taken as uniform, since the capability curve serves as a capability index only and is not based on any given set of accident conditions as an accident performance evaluation might be.

Since the percent metal-water reaction capability varies with the duration of the uniform energy and gas release, the percent metal-water reaction capability is plotted against the duration of release. This constitutes the containment capability as shown in Figure 6.2-40. The energy release rate to the containment is calculated as follows:

$$q_{IN} = \frac{Q_O + Q_{MW} + Q_S}{T_D}$$

where:

q_{IN} = Arbitrary energy release rate to the containment, Btu/s

Q_O = Integral of decay power over selected duration of energy and gas release, Btu

Q_{MW} = Total chemical energy released exothermically from selected metal-water reaction, Btu

Q_S = Initial internal sensible energy of core fuel and cladding, Btu

T_D = Selected duration of energy and gas release, seconds

The total chemical energy from the metal-water reaction is proportional to the percent metal-water reaction. The initial, internal sensible energy of the core is taken as the difference between the energy in the core after the blowdown and the energy in the core at a datum temperature of 250°F.

It is conservatively assumed that the suppression pool is the only body in the system which stores energy. That is, the considerable amount of heat storage which would take place in the various structures of the containment is neglected. Hence, as energy is released from the core region, it is absorbed by the suppression pool. Energy is removed from the suppression pool by heat exchangers rejecting heat to the CCSW system. Since the energy release is taken as uniform and the CCSW temperature and heat exchanger flowrate are constant, the temperature response of the pool can be determined.

The temperature of the drywell gas is found by considering an energy balance on the spray flows through the drywell, with the condition that the spray design is such that the gas in the drywell is 5°F warmer than the exiting water flow. The pressures in the two chambers are considered equal since there is at most a pressure difference of 4 feet of water. The partial pressure of water is conservatively considered a maximum by assuming all gases are saturated.

Based upon the drywell gas temperature, suppression chamber gas temperature, and the total number of moles in the system, as calculated above, the system pressure is determined. The containment capability curves in Figure 6.2-40 present the results of the parametric investigation. All points below the curves represent a combination of amount of metal-water reaction and energy release duration which will result in a containment peak pressure which is below the design pressure. It should be pointed out that the calculations are made at the end of the energy release duration because the number of moles of gases in the system is at a maximum and the pool temperature is higher at this time than at any other time during the energy release.

The effect of preaccident containment pressure and temperature on the time to reach flammability is small. For example, an increase in containment pressure would provide additional moles of noncondensible gases, thereby causing an increase in the time to reach a flammable concentration. However, a 1-psi increase in the preaccident containment pressure would only increase the noncondensibles by approximately 7% which would, in turn, result in an increase in the time to reach flammability of only an hour or two out of 50 hours. An increase in the drywell temperature from the normal value of approximately 135°F at 35% relative humidity to, for instance, 180°F at 100% relative humidity would only decrease the initial moles of noncondensible gases in the containment system by approximately 25%. This reduction in moles of noncondensible gases would in turn decrease the time to reach the 4% flammability limit by possibly 4 - 5 hours or a reduction in time of less than 10%.

6.2.1.3.7.3 Conclusion

Assuming the containment is not inerted, any hydrogen produced from a metal-water reaction would exit from the reactor pressure vessel at a sufficiently high temperature to be burned in the drywell. The burning of the hydrogen would reduce the total moles of oxygen in the containment system, thereby providing a greater magnitude of allowable metal-water reaction. For the case of no drywell spray, all of the noncondensible gases are conservatively assumed to be stored in the suppression chamber. The allowable containment capability as shown by the flat portion of the curve on Figure 6.2-40 would be approximately 18% for the case of no burning. The burning of hydrogen gas in the drywell as evolved would increase the allowable metal-water reaction to approximately 32%. This is a factor of over 32 greater than the less than 1% metal-water reaction calculated over the entire spectrum of breaks. Although the burning of the hydrogen increases the energy content of the containment system, the total moles of noncondensible gases is substantially reduced and thus the capability for metal-water reaction actually increases. The curves with containment spray assume rated operation of only one of the two loops. Were the hydrogen thus formed not to burn, it would mix with all the air in the containment and the resulting hydrogen-air moles mixture would be under 2.5%. This is well below the flammability limit if the drywell is not inerted).

Given that the hydrogen does burn in a noninerted containment, the total energy involved would not be large. The LOCA blowdown energy is about 400 x 10^6 Btu whereas the burning of H_2 with all the O_2 in the containment air would only liberate 18 x 10^6 Btu assuming the burning of 170 pound-moles of H_2, which is 28% by volume of H_2. If all the energy were deposited in the containment walls, the wall temperature would increase only 180°F. Actually, upon ignition, the air-steam mixture would be vented into the pool and quenched, and even though mixed mean-gas temperatures momentarily could reach 2000°F, the actual wall temperature would increase only 10°F.

Typical pressure-time curves as a function of burning rate are shown in Figure 6.2-41. Even for a rapid burn of the entire mixture in 0.5 seconds, the containment would survive since a safety factor in excess of 2 has been applied in the design pressure rating. Thus, even if the extremely low probability event that a sufficiently large break were to occur, that a large amount of hydrogen accumulated, and that it somehow ignited, containment integrity would be retained.

Figure 6.2-40 shows the capability of the pressure suppression containment to tolerate a broad spectrum of postulated metal-water reactions associated with a

LOCA. The initial portion of the curves on Figure 6.2-40 covers the time span during which the uniform energy release rate is high enough to generate steam within the drywell. All gases are thus transferred to the suppression chamber. When the duration is sufficiently long, the containment spray is sufficient to absorb all the energy without steam generation. The containment capability then increases with time as energy is removed from the system.

Even without containment spray, the pressure suppression system can tolerate a significant amount of metal-water reaction significantly greater than that actually calculated across the break spectrum consistent with the core cooling systems provided.

Therefore, that even without containment spray or inerting, the capability of the containment to tolerate postulated metal-water reactions following a LOCA is several orders of magnitude above that which is conservatively estimated to occur consistent with the case cooling provisions incorporated..

6.2.1.3.8 Containment Subcompartments - Pipe Break in the Subcompartment Between the Reactor Shield Wall and the Reactor

Section 3.6.2 provides a discussion of the jet impingement forces which are postulated to act on the concrete reactor shield wall surrounding the reactor.

6.2.1.3.9 Seismic Analysis

Seismic studies of the drywell and the pressure suppression chamber were conducted by John A. Blume and Associates of San Francisco, California. The results of this study are summarized in Section 3.7.2.2.1. The suppression chamber seismic analysis was updated in the Mark I Plant Unique Analysis Report to incorporate the effect of the Mark I modification.[7]

6.2.2 Containment Heat Removal System

Containment cooling is the operating mode of the low pressure coolant injection (LPCI) subsystem initiated to cool the containment in the event of a LOCA. This section describes the primary components and major functions of the containment cooling subsystem including: suppression pool cooling, drywell spray, and suppression chamber spray. The term containment spray, as used within this section, refers to drywell spray and suppression chamber spray collectively. A description of LPCI system pumps and related piping and valves is provided in Section 6.3.

During normal operation, containment cooling is provided by air handling units located in the drywell. Normal drywell cooling is addressed in Section 9.4.

6.2.2.1 Design Bases

The design basis of the containment cooling mode of the LPCI system is:

A. To provide the containment cooling function to meet containment capability requirements. Containment temperature and pressure capability requirements are described in Section 6.2.1.

B. To provide redundancy in critical components to meet reliability requirements.

C. To operate without reliance upon external sources of power.

D. The containment cooling mode of the LPCI system is designed so that each component of the system can be tested and inspected periodically to demonstrate availability of the system.

6.2.2.2 System Design

As shown in Drawings M-29, Sheet 1 and M-360, Sheet 1, two separate and independent containment cooling subsystems are provided to remove heat from the containment, reduce containment pressure and restore suppression pool temperature following a postulated LOCA. Each containment cooling subsystem consists of two LPCI pumps, one containment cooling heat exchanger, one drywell spray header, and a separate spray line terminating at a common suppression chamber ring header. As shown in Drawings M-29, Sheet 2 and M-360, Sheet 2, heat exchanger cooling water is provided by two containment cooling service water (CCSW) pumps in each containment cooling subsystem. Refer to Section 9.2 for a description of the containment cooling service water system. The containment cooling subsystem utilizes the same major components as the LPCI subsystem, plus additional piping and valves to direct cooling water to the containment. The configuration of one LPCI pump, two CCSW pumps and one LPCI heat exchanger has been analyzed to result in acceptable containment response following a DBA (see Sec. 6.2.1.3.2.2). The post-DBA NPSH requirements of the LPCI pumps are given in Sec. 6.3.3.4.3.

The containment cooling subsystem contains equipment which provides three different containment cooling functions: suppression pool cooling, drywell spray, and suppression chamber spray. All containment cooling functions are manually initiated.

The suppression pool cooling mode uses LPCI pump(s) to provide flow from the suppression pool through the containment cooling heat exchangers and to return the cooled water to the suppression chamber through the LPCI full-flow test line. Motor-operated valves in either of the redundant LPCI loops are manually controlled to provide any required division between suppression pool cooling flow and LPCI flow to the reactor vessel. Suppression pool cooling may also be initiated following a LOCA using a portion of the nonselected LPCI loop, which is not required to perform a LPCI function. Since the suppression pool cooling valves are downstream of the LPCI outboard injection valve, closure of the injection valve by the LPCI loop selection logic will isolate suppression pool cooling (refer to Section 7.3). The LPCI outboard injection valve control logic allows the operator to manually override the auto close signal for the injection valve and use the nonselected LPCI loop for suppression pool cooling.

The containment spray mode uses LPCI pumps to deliver water from the suppression chamber through the containment cooling heat exchangers to spray headers in the drywell and/or suppression chamber. The system valve control logic permits the operator to provide any required division between containment spray flow and LPCI flow. Containment spray cools noncondensible gases and condenses steam in the containment following a postulated LOCA. Post-LOCA operation of the drywell and suppression chamber sprays is also used to assist the natural convection and diffusion mixing of hydrogen and oxygen. Drywell sprays also remove post-LOCA airborne halogen and particulate fission products from the drywell atmosphere. Drywell and suppression chamber sprays may also be used to respond to other non-LOCA containment emergency conditions in accordance with emergency operating procedures.

Total system flow and LPCI flow indications facilitate operator determination of the flow distribution between the LPCI injection flow path and containment spray or suppression pool cooling flow path. Various interlocks are provided for the valves that control the diversion of flow from LPCI mode to containment cooling mode. Refer to Section 7.4 for a description of the interlocks provided.

Separate containment cooling spray lines terminate at two ring headers in the drywell and two separate cooling spray lines terminate at a common ring header in the suppression chamber. These ring headers are provided with spray nozzles which will assure the proper distribution of water spray. The nozzles produce a controlled spray pattern and are designed to provide the desired water particle size while preventing plugging. Additional containment spray header design information is provided in Table 6.2-7.

Each containment cooling loop is normally cross-tied to the other loop. The pumps and heat exchangers are located in each of two corners of the reactor building in shielded rooms on the basement floor. Each heat exchanger/pump room has the necessary piping and instrumentation to perform in any of the containment cooling modes. The cross-tie header between the otherwise separate subsystems makes it possible for the LPCI pumps in one room to deliver their flow through the second room's piping. This crosstie is located in a well protected basement floor area and has two normally keylocked open, motor-operated valves. The valves may be closed from the control room if loop isolation is necessary. Separation of the piping provides protection against missiles in the vicinity of the reactor in that only one of the two flow paths must be assumed to be incapacitated by missiles. Missile protection shielding is provided by routing piping along the reactor building structure walls as much as possible.

The containment cooling heat exchangers are sized on the basis of their required duty to meet the containment capability. Refer to Section 6.2.1 for a description of the suppression pool cooling requirements. The heat exchangers are designed to withstand the maximum pressures corresponding to the shutoff heads of the CCSW and LPCI pumps. When service water is flowing, the pressure on the tube side of the heat exchanger is maintained 7 psi higher than the pressure on the shell side when the flow from one LPCI pump (20 psi higher when the flow from two LPCI pumps) is passing through the heat exchanger to prevent shell side water leakage into the service water and subsequent discharge to the river. Instrumentation is provided to monitor ΔP between the LPCI heat exchanger tube side and shell side both locally and remotely in the control room. Additional containment cooling heat exchanger design information is provided in Table 6.2-7.

Since the LPCI flow passes through the containment cooling heat exchangers, containment heat may be rejected during post-LOCA LPCI mode operation by starting the CCSW pumps (when sufficient electrical power is available) to provide cooling to the heat exchangers. This results in the transfer of heat from the suppression pool to the CCSW system. During this mode of operation, suction is taken from the suppression pool, pumped through the containment cooling heat exchangers to the reactor vessel, and back to the drywell via the postulated break. When the drywell water level reaches the level of the containment vent pipes, the water flows through the vent pipes to the suppression pool.

Stagnant water conditions in the containment cooling heat exchangers (EPNs 2(3)-1503-A&B) during standby conditions cause both pitting and corrosion of the 70-30 CuNi tubes.[34] This has resulted in heat exchanger tube leaks and excessive equipment outage durations. Various materials were evaluated for better corrosion resistance and AL-6XN was selected as the replacement tube material. A limited number of tubes will be replaced with AL-6XN tubes as tubes fail. (AL-6XN has been accepted by ASME under Code Case N-438).

To ensure that other design basis evaluations are not invalidated by replacement of these tubes, the number of tubes plugged or replaced in each heat exchanger will be limited such that the total reduction in heat removal capability will not exceed that which would result from plugging 6% of the 70-30 CuNi heat exchanger tubes. The 6% limit is based on the number of excess tubes provided in the containment cooling heat exchanger design. The 6% replacement limitation will ensure that the design basis heat exchanger capability will not be reduced. The relationship between plugging tubes and replacing 70-30 CuNi tubes with AL-6XN tubes is shown in Figure 6.2-42.

The effect of this modification on flow induced vibration and seismic response will result in a design equal to or slightly more conservative than the original design. Additionally, AL-6XN's thermal expansion is close enough to that of the CuNi material so as to not cause a warpage problem with both AL-6XN and CuNi tube material installed in the same heat exchanger.

6.2.2.3 Design Evaluation

6.2.2.3.1 Containment Cooling Performance Analysis

Following a postulated LOCA, the containment cooling subsystem is capable of limiting the containment long-term pressure rise. The applicable post-LOCA containment response analyses are provided in Section 6.2.1. These analyses describe various containment post-LOCA conditions considering various combinations of emergency core cooling system (ECCS) and containment cooling systems in operation. These analyses demonstrate that the containment cooling subsystem will provide the required containment cooling following a postulated LOCA.

Following a design basis LOCA, containment heat rejection is not necessary during the short period of time in which all available ECCS pumps are assumed to be operating to restore the core coolant level. The containment cooling function can be performed after the core is flooded, which is accomplished within a few minutes even for the largest line break. After the core has been flooded to two-thirds height, one LPCI or core spray pump is adequate to maintain this level. One or more of the remaining LPCI pumps in conjunction with CCSW can be used to cool the containment. Analyses have been conducted to determine the containment cooling heat exchanger heat transfer rate under various flow conditions. The analyses of the containment long-term response to a DBA-LOCA with various pump combinations and flows are discussed in Section 6.2.1.3 and Table 6.2-3.

6.2.2.3.2 Suppression Pool Water Contamination Analysis

Contamination of suppression pool water leading to an ECCS failure over an extended operating period has been evaluated considering both normal operating and accident conditions.

The major sources of potential contaminates are drywell paint, fibrous insulation, and miscellaneous sources such as insulation metal covering, ventilation sheet metal, rust, or possibly metal pieces from failed components.

The chemical, temperature, and radiation resistance of the containment coatings together with periodic inspection and maintenance results in only a remote possibility of suppression pool strainer clogging due to post-accident coating failure. Additional containment coating information is provided in Section 6.1.

Fibrous insulation is used to cover only a limited area of piping. As part of compliance with NRC IE Bulletin 96-03, “Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors”, the inventory of fibrous insulation within the Unit 2 and 3 drywells was determined, and administrative controls are in place to control changes to the quantity of fibrous insulation.

Miscellaneous items are expected to contribute a negligible volume of contaminates in comparison to the suppression pool water volume. Any particles contributed are expected either to be stopped by strainers if they reach that position or to be colloidal rust type particles which would have little or no effect on ECCS pump seals or bearings.

As well as having limited contaminate sources, minimal probability of problems exist because of the circuitous path from the drywell to ECCS pump suctions. Particles first must pass through 1 x 1 ½-foot openings from the drywell to the 8-foot suppression pool downcomers. The downcomers are connected to large spherical shells which are interconnected by 4-foot diameter pipes forming the inner suppression pool ring header. From this header, the path to the suppression pool is through 96 circumferentially spaced 24-inch diameter pipes which extend below the suppression pool water line. The path then proceeds through four suppression pool suction strainers, the lowest point of which is located about ⅓ of the suppression pool water level height above the suppression pool bottom. From the strainers the path leads into a 24 inch suction ring header and then to the pump suctions. This path is quite circuitous, providing many places to trap foreign objects and also spreading the particles that do get through uniformly throughout the suppression pool volume. Larger pieces of metal will settle to the bottom of the suppression pool, and lighter materials such as unibestos will float rather than be drawn into the ECCS pump inlets.

The average water velocity in the suppression pool during ECCS equipment operation is less than 0.1 ft/s and is not sufficient to transport particles (except for the smaller pieces in colloidal suspension). However, during a postulated blowdown from the drywell to the suppression pool, there will be a less idealized situation. The suppression pool water will be disturbed and a certain portion of materials will be near the suction strainers. The strainers are stainless steel perforated plates with 1/8 inch diameter openings. Larger pieces and part of longer pieces (of smaller diameter) will be stopped and the strainer effective area will be somewhat reduced. To account for this possibility, hydraulic performance of the ECCS pump system is based on partial plugging of each of the four strainers with 5.8-feet head loss at 10,000 gpm assumed across each of the four strainers.

The strainers for both units were replaced in support of the Station's response to NRC IE Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors". The new strainers have an outside diameter of approximately 32.5" and an approximate length of 63". The total surface area of these strainers is approximately 118 ft^2 per strainer.

In either unit, extended operation of all ECCS pumps is not required in order to satisfy long term decay heat removal requirements. Short term DBA-LOCA cooling analyses assume the use of two LPCI pumps and one core spray pump, or two core spray pumps, to provide adequate core cooling. However, on a long-term basis, only one LPCI and one core spray pump are necessary to provide required cooling to the containment and the core. Also, the suppression pool water is demineralized and does not contain special additives. Therefore, the pH is expected to remain essentially neutral so that neither alkaline nor acidic corrosive actions are anticipated to affect ECCS pump seals or bearings.

In summary, the potentially damaging material sources are small, the volume is low in comparison to the suppression pool water volume, it is difficult for contaminates to reach the suction strainers and even more difficult to reach the pump. In addition, pump flow requirements for long term operation are low. These factors, in conjunction with a low probability of occurrence of a major accident, lead to the conclusion that the probability of suppression pool contamination creating a safety problem is extremely remote, to the point of being negligible. This position is further enhanced by the normal feedwater supplies which would be available when considering the long term operating requirements.

6.2.2.3.3 LPCI Heat Exchanger

A fracture toughness analysis was performed to determine adequacy of the shell material on the LPCI heat exchanger secondary side. The heat exchanger shells were designed as Quality Group Class C and were constructed of carbon steel A-212, Grade B material. They were built to requirements of ASME Section III, 1965 edition. The fracture toughness was calculated at the minimum heat exchanger service temperature of 51°F. The analysis indicates that approximately 1.5 x 10^6 heatup and cooldown cycles would be required to propagate an initial crack of 0.010 inches (the maximum crack size that could go undetected by inspection) to a critical crack size of 5.25 inches. The NRC evaluated these results and after performing their own confirmatory analyses concluded that the shell material on the secondary side of the LPCI heat exchangers has adequate fracture toughness.

6.2.2.4 Tests and Inspections

Because containment cooling is an operating mode of the LPCI system, LPCI system testing partially verifies that the containment cooling subsystem is functional. Additional tests are periodically performed to verify that containment spray is operable. The containment spray header discharge valves are tested by individually operating the header isolation valves. Control system logic provides for automatic return of the valves from the test mode to the operating mode if LPCI initiation is required during testing. An air test of the drywell spray headers and nozzles is performed periodically to verify operability of the drywell spray function.

Eddy current testing is performed during inspection of replacement containment cooling heat exchanger tubes.

6.2.3 Secondary Containment Functional Design

The description presented in this section is applicable to Units 2 and 3, since the secondary containment is common to both units. This description includes the design basis and design features of the secondary containment (reactor building) structure and all interfacing structures and systems needed to ensure its integrity. A design evaluation is provided which addresses performance characteristics. Tests and inspections needed to verify that secondary containment is operable and the instrumentation required to monitor and operate secondary containment are also described.

6.2.3.1 Design Basis

From a safety consideration, the primary purpose of the secondary containment is to minimize the ground level release of airborne radioactive materials and to provide for a controlled, elevated release of the building atmosphere under accident conditions. The reactor building serves as the secondary containment structure. It provides secondary containment when the primary containment is required to be in service and provides primary containment during reactor refueling and maintenance operations when the primary containment system is open. The building meets any combination of the above as may be required by the operation of Units 2 and 3. Specific design bases of secondary containment are as follows:

A. The reactor building is designed so that under neutral wind conditions the building is maintained at an internal negative pressure of ≥1/4 in.H_2O.

B. Exfiltration from the building does not exceed 100 % of the building volume per day for wind speeds on the order of 40 mph.

C. The reactor building is capable of withstanding an external wind loading equivalent to a wind velocity of about 110 mph.

D. The seismic design and tornado analysis of the reactor building are in accordance with Chapter 3.

E. The reactor building is designed to withstand an internal pressure of 7 in.H_2O without structural failure and without pressure relief. Provisions are made to relieve reactor building pressure in excess of the design pressure in the unlikely event of a rupture of the high energy piping within the building. Relief devices (blowoff panels) are provided to assure that building structural integrity will not be impaired.

F. Means are provided for exhausting treated air from the reactor building using the standby gas treatment system (SBGTS).

G. Means are provided for periodically monitoring the leak-tightness of the reactor building as described in Section 6.2.3.4.

In addition to the above, the reactor building structure is designed and constructed in accordance with applicable state and local building code requirements.

6.2.3.2 System Design

A single reactor building completely encloses both the Unit 2 and Unit 3 reactors and primary containments. The containment barrier function of the reactor building is achieved by minimizing leakage of air through the airlocks, pipe and electrical penetrations, and the building walls and roof.

During normal operation, pressure in the reactor building is automatically maintained at a negative pressure (about 1/4 in.H_2O, gauge) by controlling the exhaust air dampers to prevent exfiltration of any airborne radioactive contamination, even under high wind conditions.

Other functions of the reactor building are to enclose the reactor and associated equipment and protect it from outside elements. The building provides the necessary space for the equipment in its planned arrangement and for its economical and safe operation. The space and layout are such that the equipment can be placed and also removed if necessary. Operation of the reactor requires that certain parts of the building and equipment be moved and conveniently stored within its walls.

The Secondary Containment consists of the Reactor Building and a portion of the Main Steam Tunnel and has a minimum free volume of 4,500,000 cubic feet.

6.2.3.2.1 Reactor Building

The reactor building consists of the monolithic reinforced concrete floors and walls (enclosing the nuclear reactors, primary containments, and reactor auxiliaries) and the building superstructure with sealed panel walls and precast concrete roof. This building is a cast-in-place, reinforced concrete structure from its foundation at elevation 472'-6" to elevation 613'-0". A steel-framed top story with lateral bracing is located at this level. The reactor building is founded on competent rock at elevation 472'-6". The foundation of this building is reinforced concrete and is 297 feet long by 150 feet wide. At elevation 517'-6", the dimensions of this structure diminish to 297 feet by 120 feet, 6 inches. A reinforced concrete passageway for the accommodation of the steam and feedwater lines enters the building at this elevation.

The steel-framed top story has precast concrete deck units with insulation and insulated metal sidewall construction. The frame, in addition, supports a runway for the 125-ton traveling bridge crane. The crane rail supports are rigidly fastened to the reactor building superstructure. The reactor building overhead crane has safety lugs on both the bridge and the trolley that prevent derailment.

The concrete shielding surrounding each primary containment, an integral part of the reactor building, occupies the central part of each unit. Access to the drywell and reactor head space is obtained by removing a large concrete plug in the operating floor with the bridge crane. The reactor building houses the Unit 2 and 3 refueling and reactor servicing equipment; new and spent fuel storage facilities; and other reactor auxiliary or service equipment, including the emergency core cooling systems (ECCS), isolation condenser systems, demineralizers, standby liquid control systems, control rod hydraulic system equipment, and components of electrical equipment. The general arrangement of the reactor building and the principal equipment is shown on Drawings M-6 and M-8.

The structural and shielding design of the reactor building are discussed in Chapter 3 and Section 12.3, respectively.

Special sealing methods were used throughout the construction of the reactor building. The sheet metal siding panels have interlocking joints sealed with vinyl plastic gaskets and special caulking compounds as shown in Figure 6.2-43. Other joints are sealed with such materials as rubber strips, two-sided adhesive tapes, and special caulking. Screw holes are caulked. The reactor building parapet is sealed with urethane foam.

The reactor building roofing is made of a vapor barrier overlaid by 1-inch thick (minimum) loose-laid board insulation, covered with 10-year, single-ply, elastomeric-membrane fabric, and ballasted with paver blocks. Steel holddown clips on the corners of the roof slabs are welded to the roof purlins. Longitudinal and transverse joints are filled with mastic sealer, and the corner recesses are filled with grout.

6.2.3.2.2 Reactor Building Airlock Doors

Reactor building airlock doors have weather-strip-type rubber compression seals. The design basis leakage limit is 25 ft^3/min per door at ¼ in.H_2O pressure. Each pair of personnel access control doors is electrically interlocked so that only one of the pair may be open at a given time.

There are two personnel air locks between the turbine and reactor buildings at grade elevation. There is one equipment airlock and one equipment access door from the outdoors into the reactor building on the ground floor. In addition, there is one personnel air lock into the reactor building from the turbine building main floor. The equipment access door is enclosed on the outside by a material interlock structure, however this structure is not considered to provide secondary containment. There are personnel airlocks from the Unit 2/3 diesel generator room to the Unit 2 and Unit 3 HPCI rooms, and to the Unit 2 reactor building. There is an access door from the Unit 2/3 diesel generator room to the Unit 2 high pressure coolant injection (HPCI) pipeway. This access door is considered a secondary containment boundary and is locked. Sufficient administrative measures control the opening of this door such that secondary containment is maintained. There are other personnel airlocks from the turbine building to the Unit 2 and Unit 3 MSIV rooms (X-areas).

Inside the reactor building between Units 2 and 3 there are ordinary single doors at three floor levels.

6.2.3.2.3 Reactor Building Pipe and Electrical Penetrations

Reactor building pipe and electrical penetrations are sealed as necessary to minimize air leakage and meet the infiltration specification. Leakage through minor apertures is acceptable. Electrical penetrations may be caulked with oakum and a soft setting compound, for example. Airflow through pipeways may be blocked sufficiently with sheet metal curtains or collars. Larger annuli may be blocked with appropriate fabric sleeves (e.g., insulation for hot pipes). Small annuli between pipes and the concrete opening may be left open.

6.2.3.2.4 Secondary Containment Isolation System

Secondary containment isolation consists of closing the reactor building ventilation system isolation dampers, shutting down the ventilation fans, and activating SBGTS. The reactor building ventilation system is described in Section 9.4, and SBGTS is described in Section 6.5.

Secondary containment isolation of both units is automatically initiated in response to airborne contamination or a refueling accident (both detected by the reactor building air monitoring system) or by a Group 2 primary containment isolation signal in either unit. The reactor building air monitoring system is described in Section 11.5.2.4, and the primary containment isolation signals are described in Section 7.3. The refueling accident is analyzed in Section 15.7.3.

Following isolation, the SBGTS will restore the negative pressure inside the reactor building and will remove radioactive contamination from the reactor building air before discharging it through the 310-foot chimney.

The reactor building ventilation isolation dampers for each unit are located adjacent to the reactor building in the turbine building, on the supply and exhaust fan deck at elevation 581'-0". There are two dampers in series in both the supply and exhaust ducts.

6.2.3.3 Design Evaluation

The containment system provides the principal mechanism for mitigation of accident consequences with the reactor building atmosphere being filtered and discharged through the 310-foot chimney for elevated release. The offsite accident consequences are relatively insensitive to the reactor building inleakage rate as long as the SBGTS can maintain the building at a negative gauge pressure and prevent exfiltration at low wind speeds.

Exfiltration from the secondary containment would be minimized by construction to the specified leakage limit of 1600 ft^3/min. at internal negative pressure of ¼-in.H_2O (gauge), with 40 mph winds. If high wind exfiltration were to occur, dilution of any released radioactive material would be large so that potential exposures are inherently minimized. Such exfiltration is not postulated since the design and operation of the reactor building ventilation system and SBGTS maintain the building at a slight negative pressure under both normal and accident conditions. This negative pressure is maintained for outside winds of any velocity or direction, and precludes exfiltration from the building.

The wind velocity pressure, or stagnation pressure was correlated by the following equation.[35]

$P_s = AV^2$

where:

A = proportionality constant

P_s = stagnation pressure

V = wind speed, mph

The leakage rate tests at low pressure differentials indicate that leakage rates may be correlated by the following equation:[36]

Leakage rate = $a(\Delta P) + b(\Delta P)^{1/2}$

where "a" and "b" are constants which are dependent upon the leakage characteristics of the building and ΔP is the pressure differential between the building atmosphere and the outside.

The model used to calculate reactor building inleakage assumes that two adjacent sides of the building are exposed to the wind, and that two adjacent sides are on the leeward side of the building. On the windward side of the structure, the stagnation pressure varies from approximately 50% to 90% of the wind velocity pressure. Thus, in the model the static pressure acting on the two adjacent sides on the windward side of the building is considered to be 90% of the wind stagnation pressure. On the leeward side of the building, the negative static pressure adjacent to the building siding varies from 30% to 60% of the wind velocity pressure, therefore the negative static pressure acting is considered to be 50% of the wind velocity pressure. The above model represents the worst possible differential effect on the building since component effects of the wind velocity vector are not considered.

Using the above criteria, the calculated building leakage is then predicated on maintaining a building pressure which is 1/4 in.H_2O negative with respect to the external pressure on the leeward side of the building. Total leakage rates combine effects of leakage through the reactor building siding; personnel access doors; equipment access doors; and the electrical, vent, duct, and piping penetrations.

Table 6.2-8 lists the building leakages under various wind velocities from specific areas and for the total structure. The basis for the 477 ft^3/min leakage at zero wind speed is a summation of air infiltration from all potential leak paths, considering a 1/4 in.H_2O differential pressure across these paths. At wind velocities other than zero, the building leakage remains constant on the leeward portion of the building and is proportional to the square root of the ΔP on the windward side.

The following reactor building external areas are covered with siding:

A. North side	300 ft x 38 ft =	11,400 ft^2
B. East and west sides	120 ft x 47 ft =	5640 ft^2 (each)
C. South side	300 ft x 47 ft =	14,100 ft^2

A typical siding detail is shown in Figure 6.2-43.

The data in Table 6.2-8 indicate that SBGTS is more than adequate to maintain the reactor building negative pressure following an isolation signal (no accident case), even at wind speeds of 100 mph, provided that the SBGTS is put in operation immediately following the isolation signal.

To calculate the reactor building exfiltration rates following a loss-of-coolant accident (LOCA) or refueling accident, a mathematical model based on the reactor building temperature rise has been developed. This model assumes a 10-minute delay between the accident and the time SBGTS is started. Manual loading of SBGTS onto the diesel generators is not assumed until after 10 minutes, when core flooding is complete. This assumption is conservative since SBGTS will automatically start following an accident. This heat rise considers the rapid increase in temperature of the drywell and torus and the heat being generated by the ECCS pumps in one unit. Figure 6.2-44 shows exfiltration following LOCA conditions. The non-accident unit is considered to remain on the curve which is the maximum heat generation case.

As shown in Figure 6.2-44, the ground level exfiltration rates increase with time until the SBGTS is put in operation, which is 10 minutes after the LOCA. During the period when the reactor building internal pressure is positive, total ground level exfiltration is calculated to be 43,000 cubic feet. Corrected to 50-mph wind velocity, ground level exfiltration would be 80,000 cubic feet.

Exfiltration rates following a refueling accident are summarized on Figure 6.2-45. Refueling accident conditions are accompanied by a lesser degree of ground level exfiltration than the LOCA case. This is due to the smaller heat loads in the reactor building following a refueling accident.

Calculated ground level exfiltration following a refueling accident is 22,000 cubic feet. Applying the 50-mph wind velocity correction factor, exfiltration would be 43,000 cubic feet.

Calculations have been performed to determine the potential dose resulting from possible exfiltration during the 10-minute period prior to the operation of the SBGTS. Results show that maximum doses are 2×10^{-3} rem and 9.2×10^{-1} rem to the thyroid for the LOCA and refueling accidents, respectively. These dose estimates are expected to increase by 26% following extended power uprate. These values are several orders of magnitude less than the guideline values of 10 CFR 100. Additional analyses were performed using Alternative Source Term; these results are also regulatory limits per 10 CFR 50.67.

Analysis shows that the secondary containment will sustain about 7 in.H_2O (36.5 lb/ft^2) positive pressure, due to accident conditions such as escape of primary containment pressure or leakage from a steam or hot water line, without exceeding specified leakage limits and without structural failure. Tests show the blowoff panels would relieve at 70 lb/ft^2 without other damage to the superstructure. The blowoff panels and other tornado protection measures are described in Section 3.3.

Four dP sensors, one on each side of the building, are used to compare the pressure external to the reactor building with the internal pressure on the 613 ft elevation operating floor. The points selected for external measurement are on the exterior of the siding above the operating floor level. The signal from each dP transmitter is then sent to a circuit which selects the lowest differential pressure to control the position of the reactor building ventilation system exhaust fan dampers. The controller is set to maintain a negative pressure difference of at least 1/4 in.H_2O relative to the pressure on the side of the building with the lowest atmospheric pressure. Fan mass flow varies as a function of wind direction and velocity.

6.2.3.4 Inspection and Testing

The reactor building leakage rate is tested by isolating the building and operating the SBGTS. The SBGTS flow control valve is adjusted to obtain 4000 ft^3/min, and the building ΔP is measured. The building is required to hold at least 1/4 in.H_2O vacuum to pass the test.

The reactor building inleakage is tested prior to refueling, when an operation or event brings the reactor building leakage integrity into question, or at least every 24 months.

Secondary Containment is maintained as defined in Technical Specifications in operational modes 1, 2, 3 and when handling irradiated fuel in the secondary containment, during core alteration(s) and operations with a potential for draining the reactor vessel.

Double interlock doors on equipment and personnel access airlocks prevent the breaching of containment integrity. Possible deterioration of airlock door seals and penetration seals is detected during periodic inspections and tests. Corrective maintenance is performed as necessary.

6.2.3.5 Instrumentation Requirements

The instruments required to support the secondary containment are those instruments necessary to control reactor building pressure and to initiate secondary containment isolation. These include the reactor building pressure sensors, process radiation monitors in the reactor building exhaust ducts and refueling floor, drywell pressure sensors, and reactor water level monitors.

6.2.4 Containment Isolation System

6.2.4.1 Design Bases

The primary containment system performance objective and design bases are stated in Section 6.2.1.1. The containment isolation system is required for the primary containment system to meet its performance objective to provide a barrier which, in the event of a loss-of-coolant accident (LOCA), will control the release of fission products to the secondary containment.

6.2.4.2 System Design

6.2.4.2.1 Isolation Valves

Isolation valves are provided on lines penetrating the drywell and pressure suppression chamber to ensure containment integrity when required during emergency and post-accident periods. Isolation valves which must be closed to ensure containment integrity immediately after a major accident are automatically controlled. Section 7.3.2.4 describes changes which have been made to primary containment isolation valves to preclude automatic opening when the isolation signal is reset so that manual opening by an operator is required, thus avoiding accidental automatic opening. The control logic for the containment isolation valves is described in Section 7.3.2. Refer to Table 6.2-9 for a tabulation of the principal containment penetrations and the automatic isolation valves provided to maintain containment integrity. This table does not list instrument or electrical penetrations or the test, vent, or drain valves on piping between isolation valves.

Pipes which penetrate the containment and connect to the nuclear steam supply system (NSSS) are equipped with two isolation valves in series. Pipes that penetrate the containment and are open ended into the free space of the containment are also equipped with two isolation valves in series. As a general rule, one of each pair of isolation valves in series is located inside the containment, and the other is located outside and as close to the containment as practical.

Lines which open to the free space of the containment and which have two valves normally closed have the valves located outside the containment (e.g., containment spray spargers). Lines forming a closed loop inside the containment but which, as a result of pipe failure inside the contained area, may carry radioactive fluids out of the containment are generally provided with one isolation valve outside the containment. This may be either a self-actuating check valve or a remote manually controlled motor-operated valve outside the containment. For closed system piping which communicates with the suppression pool and is expected to remain submerged during a LOCA, the intact piping or the water seal acts as the penetration isolation barrier and ensures that the primary containment boundary is maintained intact until another barrier can be established to isolate the penetration.

Systems which connect to the NSSS and which may be required to have flow into the NSSS after an accident are provided with either of two valves arrangements. Either both isolation valves in series are self-actuated check valves (one inside and one outside the containment) or one is a check valve and the other is a power-operated valve (electric motor or air) that can be remotely controlled. These systems include the feedwater, low pressure coolant injection (LPCI), and standby liquid control systems. On lines where flow may be in either direction, both valves are power-operated.

In general, the closure time of all isolation valves is such that the release of fission products to the environment is minimized. The closure times of all valves on lines in systems connecting to the nuclear steam supply system are based on preventing fuel damage due to overheating with no feedwater makeup following a line break in the particular system. The valve closure time for the main steam line is based on the main steam line break accident discussed in Section 6.3. By keeping the valve closure time less than approximately 10 seconds, sufficient coolant remains in the reactor vessel to provide adequate core cooling. The valves are designed to close and to be essentially leaktight during the worst conditions of pressure, temperature, and steam flow following a break in the main steam line outside the containment.

Motive power for each of a pair of power-operated isolation valves in series is from physically independent sources to preclude the possibility of a single malfunction interrupting power to both valves. Air-operated valves which close for the normal containment isolation mode, fail closed on loss of motive power with the exception of the reactor building to containment vacuum relief valves discussed in Section 6.2.1.2.4.1. Electric motor-operated valves fail as is.

Typically, power operators on valves inside the containment are supplied with ac power and those outside the containment are supplied with dc power.

The following is the guidance used for determining which manually-operated valves are primary containment isolation valves (PCIVs) and which valves are required to be locked. Typically these valves are on vent lines, drain lines, capped branch lines, or test connections. When the principal inboard PCIV is located inside containment and the principal outboard PCIV is located outside of containment:

Valves in line, as well as test valves, located inboard of the principal inboard PCIV are not considered PCIVs.

The inboard test valve, when located between the principal inboard and outboard PCIVs, is considered a PCIV. This test valve must be locked closed when not in use.

Valves in line between the principal inboard and outboard PCIVs are considered PCIVs. These Valves will be administratively controlled on a case by case basis.

When both the principal inboard and outboard PCIVs are located outside of containment:

Valves in line, as well as test valves, located inside containment are not considered PCIVs.

Valves in line between containment and the principal inboard PCIV are considered PCIVs. These valves will be administratively controlled on a case by case basis.

Both the inboard and outboard test valves, when located between containment and the principal inboard PCIV, are considered PCIVs. Both of these test valves must be locked closed when not in use.

The inboard test valve, when located between the principal inboard and outboard PCIVs, is considered a PCIV. This test valve must be locked closed when not in use.

Valves in line between the principal inboard and outboard PCIVs are considered PCIVs. These valves will be administratively controlled on a case by case basis.

In addition, numerous principal PCIVs are manually-operated. Since these valves do not get an automatic closure signal, nor can they be remotely closed, they must be locked closed when not in use.

Instrument lines are exempt from Type C testing provided they are not isolated from containment during the performance of a Type A ILRT. Although instrument lines are exempt, Dresden Station chooses to be more conservative in regards to locking instrument line test, vent and drain valves. Therefore, test valves on instrument lines without excess flow check valves are considered equivalent to test valves on process lines penetrating containment.

The inboard test valve on an instrument line without an excess flow check valve is considered a PCIV. When not in use, this test valve must be locked closed.

Tables 6.2-10 and 6.2-11 list the Unit 2 and 3 valves which are required to be locked closed.

Locked-closed, manual, containment isolation valves required to be opened to conduct sampling, may be opened one line at a time provided the following conditions are met:

A. An operator is dedicated to attend to the valves;

B. The operator is in continuous communication with the control room; and

C. The operator is capable of closing the valves so the penetration can be rapidly isolated in the event containment isolation is required.

Drywell sample valves and reactor water sample valves which automatically close due to a containment isolation signal may be opened after isolation using a manually-operated, keylock bypass switch.

Similarly, the two 2-inch containment vent and purge isolation globe valves (AO-1601-61 and AO-1601-62) and the outboard 6-inch butterfly valve to SBGTS (AO-1601-63) may also be overridden and reopened after isolation for post-LOCA containment venting. If operation of the augmented primary containment vent system (APCVS) is required, circuitry is provided to override the isolation signal to the 18-inch containment vent valves, AO-1601-23, -24, and -60 as described in Section 6.2.7.

Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design-Basis Accident Conditions," identified the potential for thermally induced overpressurization and subsequent rupture of isolated, water-filled piping sections in containment. This condition could jeopardize the ability of the accident mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage. When the arrangement of inboard and outboard containment isolation valves create a post-accident overpressure potential for the piping between them, a relief device (relief valve discharging to the drywell) was installed between the isolation valves to mitigate the overpressurization. Alternately, the effect of this thermal pressurization has been analyzed using Appendix F of Section III of the ASME B&PV Code, 1977 Edition through S'77 Addenda. The results demonstrate that the stresses remain within Appendix F allowables. Therefore, the pressure boundary integrity of primary containment is maintained.

Instrument line excess-flow and simple check valves are described in Section 3.8.2.1.9.

6.2.4.2.2 Main Steam Isolation Valves

The main steam isolation valves (MSIVs) are 20-inch air-spring-operated, balanced, "Y"-type globe valves. Figure 6.2-46 shows the typical design features for this type of valve. The Unit 3 inboard MSIVs are equipped with leakoff lines as shown in Drawing M-345-1. This valve combines full-port design with straight line flow to provide a very good flow pattern and utilizes upstream pressure to aid in valve closure by tilting the actuator toward the upstream side of the valve. The balancing feature of the valve makes it possible to take advantage of the upstream pressure to aid in holding the valve closed and has the added advantage of requiring a smaller actuator cylinder to open the valve. The balancing feature design aids holding the valve closed by allowing the full upstream line pressure to bleed into the chamber above the plug through the balancing port to exert a force on the plug internals in a direction to hold it against the seat. When the actuator starts to open the valve, the stem lifts the pilot off its seat to vent the steam inside the plug into the downstream line. As the stem travel continues, the plug is lifted off the main valve seat to open the valve port.

The valve actuator is completely supported by four spring guide shafts. Coil springs located around the spring guide shafts are used for closing the valve in case of air failure. The valve is opened and held in the open position by compressed air. The valve closes within the specified time with air and spring action. Analyses indicate that for a main steam line break fuel cladding perforations are avoided for MSIV closure times of approximately 10 seconds. Refer to Section 15.6.4. For added margin, the valve closure time is controlled between 3 and 5 seconds by a hydraulic (oil) dash pot which is mounted below the main air cylinder and is equipped with an external bypass pipe and flow control valve.

A schematic control diagram for the MSIVs is shown in Figure 6.2-47. To open an MSIV (position shown in Figure 6.2-47), the solenoids on both three-way solenoid valves (4) and (5) are energized to shift four-way valve (2) into the position shown. With the four-way valve (2) shifted to the position shown, air is admitted to the lower side of the air cylinder on the main valve to open the valve and exhaust the air from the top of the cylinder.

To close the MSIV, the solenoids on both three-way solenoid valves (4) and (5) are deenergized to shift valves (4) and (5) and four-way valve (2) into the position opposite that shown in Figure 6.2-47. In this position, compressed air enters the top of the cylinder and air below the piston is exhausted, forcing the valve closed. To exercise the MSIV, valves (4) and (5) are deenergized which positions valve (2) opposite to the position shown and the solenoid on the three-way solenoid valve (6) is energized to shift the four-way valve (1) into the position opposite that shown. This allows the springs on the main valve to force the cylinder downward, exhausting the air through the flow control valve associated with valve (1). The main valve is returned to the open position by deenergizing the solenoid on valve (6) to shift valve (1) back to the position shown and reenergizing the solenoids on valves (4) and (5) to shift valve (2) back to the position shown thereby permitting air to enter the lower side of the air cylinder. As a fail-safe feature, the main valve will close on loss of compressed air or loss of both ac and dc voltage to solenoid valves (4) and (5). In both of these cases, four-way valve (2) shifts position and exhausts the air below the cylinder of the main valve.

On several occasions early in plant life the Unit 2 MSIVs failed to operate due to sticking pneumatic valves which control the flow of air to the MSIV cylinder operator. The cause of the failures was determined to be excessive heat in the vicinity of the valves and the highly sensitive nature of the small clearance pneumatic valves to oil-contaminated air causing binding due to the build up of deposits within the valves. The air control valves were replaced with "poppet valves." Poppet valves seal with elastomers between the poppet and the metallic valve seat. This design permits the clearance between the valve body and the poppet to be larger, precluding the possibility of deposits forming a mechanical bond. In addition, air conditioning equipment was added to the steam tunnel to reduce temperatures in the area of the valves. A drywell pneumatic system provides compressed nitrogen to the MSIVs inside the drywell. Compressed air for the MSIVs outside the drywell is supplied from the instrument air system. The instrument air system is separated from the service air compressors and two nonlubricated compressors and associated filters and piping are installed to form a completely separate, oil-free system. Refer to Section 9.3 for a description of the drywell pneumatic supply system.

6.2.4.2.3 Traversing Incore Probe Isolation Valves

The traversing incore probe (TIP) system, as discussed in Section 7.6, has several guide tubes which pass from the reactor building through the primary containment wall. Penetrations of the insertion guide tubes in the primary containment are sealed by means of brazing which meets the requirements of ASME Section VIII.

Each TIP system guide tube is provided with an isolation valve which closes automatically upon receipt of an isolation signal and after the TIP cable and fission chamber have been retracted. In series with this isolation valve, an additional or backup isolation shear valve is included. Both valves are located outside the drywell. The function of the shear valve is to ensure integrity of the containment in the event that the other isolation valve fails to close or in the event that the chamber drive cable fails to retract while extended in the guide tube at the time that containment isolation is required. The shear valve is a dc-operated explosive-type valve, which can shear the cable and seal the guide tube if necessary. The valve position of each type valve is indicated in the control room.

6.2.4.2.4 Containment Vent and Purge Isolation Valves

The containment vent and purge isolation valves, shown in Drawings M-25 and M-356, are designed to close automatically on a Group 2 isolation signal (see Section 7.3). The exhaust (vent) lines from the drywell and torus are connected to a common exhaust header which leads to the reactor building ventilation exhaust system and to the SBGTS. The drywell and torus exhaust lines each have an 18-inch butterfly-type isolation valve (AO-1601-23 and AO-1601-60 respectively) bypassed by a 2-inch globe valve (AO-1601-62 and AO-1601-61 respectively). The common exhaust header has an 18-inch butterfly valve (AO-1601-24) for isolation of flow to the reactor building ventilation exhaust, and a 6-inch butterfly valve (AO-1601-63) isolating flow to SBGTS.

The purge supply line to the drywell is connected to a common supply header from the reactor building atmosphere via two 18-inch butterfly drywell isolation valves (AO-1601-21 and AO-1601-22). In addition, one 18-inch line and a normally open butterfly isolation valve (AO-1601-56) taps into the drywell supply line between the two drywell isolation valves. This valve (AO-1601-56) is normally open to provide a flowpath from the suppression chamber to the pumpback air compressors for maintenance of the required differential pressure (dP) between the drywell and suppression chamber. Two 1½-inch lines and a 4-inch line with isolation valves (AO-1601-58, AO-1601-59, and AO-1601-55) tie into the supply header for inerting the containment atmosphere with nitrogen and establishing and maintaining drywell-torus dP.

The 2-inch globe valves in the exhaust lines from the drywell and torus are used to reduce containment oxygen content during operation and for containment pressure relief to either the reactor building ventilation exhaust or SBGTS. Purging and venting the containment for deinerting purposes is accomplished using the 18-inch butterfly isolation valves in the supply and exhaust lines.

6.2.4.3 Design Evaluation

6.2.4.3.1 Containment Isolation Valves

All containment isolation valves, including their power operators, are designed to operate under the most extreme ambient conditions (such as pressure and temperature) to which they may be exposed after a major accident. All isolation valves in lines connecting to the NSSS and all pipe welded connections were fully radiographed to assure their integrity. They were built to the applicable codes and all nuclear interpretations applying to those codes.

Hydrodynamic testing and stress analysis was performed to evaluate stress level margins in critical components of the 18-inch butterfly valves manufactured by the Henry Pratt Company and used as drywell vent and purge containment isolation valves.[37] The purpose of this evaluation was as follows:

A. Determine the torque values for these valves during closing at various mass flowrates and incremental valve disk angles;

B. Verify that the valves tend to close under flow conditions; and

C. Determine worst case stress level margins existing in the critical load-carrying structural members of the valve during the postulated closing event.

The first stage of the evaluation consisted of hydrodynamic testing at one-third scale. The valve used for testing was geometrically similar to the 18-inch butterfly valve and was tested in a facility that reproduced the postulated airflow resulting from containment pressure venting through the valve to atmosphere. The second stage of the evaluation consisted of an analysis of stresses in the valve shaft, pin, key, and actuator arm. This analysis was performed using, as the loading condition, the valve shaft torque values determined in the one-third scale valve test scaled to full scale.

The results of the testing indicated that the flow-induced hydrodynamic torque tends to close the valve up to the angle where the valve disk contacts the valve seat. The results of the stress analysis indicate that the worst case stress level margins in the valve load-carrying structural members are acceptable.

It was concluded from this testing and analysis that the critical internal components of the Pratt Model 2F11, 18-inch butterfly valve will retain structural integrity if subjected to the flow-induced loads resulting from a postulated design basis LOCA when used as a purge and vent containment isolation valve.

A test program for the same model 18-inch butterfly valve was also conducted by the Henry Pratt Company for Prairie Island. This test program used a 5-inch diameter model valve disk and calculated dynamic torque data approximately 7 times greater than the evaluation described above. The Dresden 18-inch, 6-inch, and 4-inch containment vent and purge valves were evaluated using this higher torque data. These evaluations also confirmed the valves' ability to close from the fully open position against the buildup of containment pressure in the event of a design basis LOCA.

6.2.4.3.2 Containment Integrity

Valve structures and containment penetrations have been evaluated to confirm their ability to maintain structural integrity and meet leak tightness requirements during the long term following a LOCA. It is not anticipated that the integrity of the primary containment will deteriorate to a point where excessive leakage will occur following a design basis accident. Individual component evaluations are described below.

The containment shell, electrical penetrations, and piping penetrations are metallic components (with a ceramic filler in the electrical penetrations) that are designed to pressure vessel standards and thus, no degradation will occur from temperature, pressure, or radiation damage.

The torus to drywell vacuum breaker valves use Nordel and silicone rubber as the elastomer and seat material and are located outside the primary containment shield wall. Thus, the ambient temperature (continuously less than 250°) and radiation exposure for these locations are less than the service rating for this material. The system temperature this material is exposed to has been postulated to approach 340°F for approximately 48 minutes and then drop to less than 250°F for the remainder of the accident. See Section 6.2.1.3.2. These materials are rated for this temperature range (up to 340°F maximum). The radiation dose after 12 hours may approach the radiation damage threshold for this material, but does not exceed their radiation capability (10^8 rads). However, the torus to drywell vacuum breaker valves and valve seats would have already served their function by this time; that is, they would have prevented bypassing steam from the drywell directly to the suppression chamber without being quenched by the suppression pool, and thus pressure suppression would have been assured. Leakage past these valve seats after pressure suppression has occurred is acceptable since it actually provides additional confidence that the drywell and suppression chamber are at the same pressure.

All other originally installed isolation valves in the primary containment system utilized metal seats, and therefore, the structural integrity and leaktightness of these valves will remain essentially unchanged following a DBA. Subsequent to the initial plant design, various isolation valves have been replaced with valves with elastomer seats or diaphragms. The elastomer materials have been evaluated to ensure their design is consistent with the fluid chemistry conditions, and the normal and accident environmental conditions presented in Tables 3.11-1 and 3.11-2, based on valve location. Consequently, each valve is capable of fulfilling its intended design function, to achieve and maintain isolation of the primary containment following a design basis event.

Buna-N rubber, Teflon, and nylon are used in certain applications in the valves discussed above, but these materials are used only in such locations that their failure will not alter the structural integrity operability of these valves.

The two manways into the suppression chamber, the drywell equipment access lock, the CRD equipment hatch, the eight shear lug inspection ports, and the drywell head and manway all have double seals. The drywell personnel access airlock doors each have a single seal. Seals for all these penetrations are made of Elastomer materials that meet the requirements of normal and accident conditions as presented in Tables 3.11-1, 3.11-2 and 3.11-3.

6.2.4.4 Tests and Inspections

Prior to initial operation, all power-operated (diaphragm or motor) isolation valves (including atmospheric vacuum relief butterfly valves) were automatically actuated and the closing time of each determined. During normal operation, each power-operated isolation valve is exercised by fully opening (or closing) at regular intervals. Closure times of all power-operated isolation valves are tested on a regular basis. Automatic isolation by a simulated automatic initiation signal from the primary containment isolation system is also tested. The frequency of valve closure tests is based on assuring a high degree of reliability. If any isolation valve fails, at least one valve in the line with the inoperable valve is placed in the mode corresponding to the isolated condition and verified to be in that mode daily.

Main steam isolation valve testing can be accomplished both during reactor operation and during shutdowns. Functional performance and leakage tests can only be performed during reactor shutdowns when access to the area of the valves is permitted. In-service exercising is used to demonstrate operability and to check closure times. The MSIVs are exercised more frequently than other power-operated isolation valves by partial closure and subsequent reopening.

Tests performed during shutdown include actuation and closure time tests to assure that the MSIVs operate properly, that the sensors are set correctly and cause the proper actuation, that the response speed is correct, and that the fail-safe features are operable. Every refueling outage the MSIV air pilot solenoid valves are tested for potential coil failure, and leaktightness tests of the MSIV and its individual accumulator check valves are performed. Testing of the fail-safe feature of the MSIVs is conducted during cold shutdown in accordance with the In-Service Testing Program.

Tests during reactor operation must be run in a manner to prevent reactor scram. The MSIV closure scram signal requires MSIV not fully open signals (Analytical Limit: less than or equal to 10% closure) of the inboard or outboard MSIV in any three lines, and for that reason in-service testing is limited to one MSIV at a time. Each MSIV is equipped for in-service exercising through the use of the slow-speed exercising circuit and three limit switches indicating fully open, 90% open, and fully closed. Exercising the MSIVs to the 90% open position can be accomplished with the reactor at normal power level.

Momentarily moving the test switch to the "test" position causes the MSIV to close to the 90% open position and then reopen. Each MSIV can also be tested for full closure from a reduced power level by moving the same test switch to the "test" position and holding it there. The MSIV being tested will slowly close as long as the test switch is held in the "test" position. Releasing the test switch at any time after the valve reaches the 90% open position causes the MSIV to return to the fully open position. Moving the test switch to the "open" position at any time will return the MSIV to the full open position.

Valve position status lights are provided. Valve closure times can be checked by reducing the reactor power level, tripping each MSIV (one at a time), and measuring the time to receive the fully closed indication.

A program for periodic testing and examination of the excess flow check valves in instrument lines penetrating the containment has also been established.

Refer to Section 6.2.6 for a discussion of the local leakage rate tests.

6.2.5 Combustible Gas Control in Containment

The primary means of containment combustible gas control is the nitrogen inerted containment. The inerted containment, combined with NCAD operation, is sufficient to ensure peak combustible gas concentrations are below acceptable limits without the need to purge or repressurize the containment. In addition, the following criteria are met:

A. Drywell oxygen is limited to less than 4% (per Technical Specifications);

B. Only nitrogen or recycled containment atmosphere is used for pneumatic control within containment; and

C. There are no potential sources of oxygen into containment other than radiolysis of the reactor coolant.

As such, reliance on a purge/repressurization system is not necessary.

In addition, various containment atmosphere control systems are installed which are capable of providing venting and nitrogen makeup during normal operation and post-loss-of-coolant accident (LOCA) conditions. In the event of a post-LOCA combustible gas mixture, the existing purge systems can be used to vent this mixture out of the containment through the charcoal beds and high efficiency particulate air (HEPA) filters of the standby gas treatment system (SBGTS). The Nitrogen Containment Atmospheric Dilution (NCAD) system, nitrogen makeup system and nitrogen inerting system are capable of adding nitrogen to the containment, thus reducing the combustible gas concentration. This section describes the systems available for combustible gas control at Dresden.

Refer to Section 6.2.1.3.7 for a discussion of the sources of hydrogen in the containment and the containment capability to handle the hydrogen generated.

6.2.5.1 Historical Basis for Combustible Gas Control System Design

The potential generation and control of hydrogen within the containment following a LOCA has been a concern since the first nuclear power plant was constructed. However, it was not until 1971 that the AEC documented its acceptance criteria for combustible gas control in Safety Guide 7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident." One of the criteria stated in the guide was the amount of zirconium metal-water reaction that was to be considered as part of the hydrogen production analysis; specifically 5% by weight of the zirconium within the reactor core selected as the upper limit. It was believed that much beyond 5% core damage, the subsequent core relocation could lead to a complete core meltdown.

The temperature response of the reactor core during a design basis accident (DBA) showed that the hydrogen generated from the metal-water reaction process would occur within a matter of minutes. To accommodate this rapid hydrogen generation, Mark I design focused on limiting the amount of oxygen within the containment, thereby transferring the flammable control parameter from hydrogen to oxygen. This change enabled the containment to accommodate any amount of hydrogen without affecting the flammable limit of the containment atmosphere.

In 1978 the NRC published 10 CFR 50.44 (43 FR 50162) which established the amount of metal-water reaction based on an average depth-of-fuel cladding involvement rather than a percentage of cladding material. The NRC chose a depth of 0.00023 inches of involvement as the new metal-water criterion. This value was selected to yield the equivalent of 5% by weight for the reactor design containing the thinnest clad. Because of the thick BWR clad design, the new rule reduced the total amount of metal-water reaction to about one-half of the amount calculated using the 5% by weight criterion for a typical Mark I design. With the new criterion, it could be shown that a containment atmospheric dilution system was sufficient without the need for inerting.

Based on evidence obtained from the Three Mile Island Unit 2 (TMI-2) accident, 10 CFR 50.44 was revised in 1982 (46 FR 58484). The revision defines the requirements for combustible gas control and specifies that BWR Mark I containments operate with an inerted containment. For those BWRs which rely on a purge/repressurization system as the primary means of combustible gas control following a LOCA, an internal recombiner or the capability for the installation of a recombiner is also required.

Quantifying the amount of hydrogen generated in a post-LOCA condition is key to the bases for the systems necessary to control combustible gas mixtures. The combination of the DBA metal-water reaction generated hydrogen and the oxygen and hydrogen produced by events such as radiolysis and corrosion is more than sufficient to yield a flammable condition within 30 days. This is the case whether or not the containment is initially inerted as determined using models and equations provided in Safety Guide 7.

The BWR Owners Group (BWROG) developed a model for radiolysis of water and documented the results in NEDO-22155. The differences between the models in Safety Guide 7 and NEDO-22155 is that the NEDO-22155 model results in hydrogen/oxygen generation rates due to radiolysis which are several orders of magnitude lower than hydrogen/oxygen rates resulting from the Safety Guide 7 model.

Using the models presented in NEDO-22155, the BWROG was able to show for a typical Mark I design that the initial inerted containment would be sufficient for the first 30 days of an accident. It showed that neither a recombiner nor venting would be needed for at least 1 month following an accident.

The NRC indicated that the models were appropriate for the major segment of accidents under consideration. For degraded core accidents where significant amounts of metal-water reaction hydrogen are produced, the hydrogen acts as an inerting component with respect to oxygen. As a result, neither set of models showed a need for an active combustible control system.

However, the NRC found that there were a small number of accidents, both within the DBA envelope and slightly beyond, where the assumptions used in NEDO-22155 were at least questionable. The NRC staff has found the models contained in NEDO-22155, which several licensees generically used to support the position of not requiring an active combustible gas control system, unacceptable for DBA applications. Safety Guide 7 guidelines have been and continue to be the basis of acceptance for the DBA events. The NRC weighed the benefits to be gained for this small number of accidents to the costs of providing recombiner capability. The NRC concluded that the costs outweighed the benefits for this limited situation. To reflect this position, the NRC issued Generic Letter 84-09. In the Generic Letter, the NRC specified that Mark I BWR plants do not need to rely on a purge/repressurization system as the primary means of combustible gas control provided that three technical criteria are met. The NRC staff, however, also indicated in the Generic Letter that if the licensee has a safety-related purge/repressurization system, which was installed to meet 10 CFR 50.44(g), the licensee must maintain that system. The intent of the Generic Letter was to provide relief from the recombiner capability.

The three criteria which must be satisfied to meet the requirements of Generic Letter 84-09 are:

A. Technical Specifications must require the containment atmosphere to be less than 4% oxygen when the containment is required to be inerted;

B. Nitrogen or recycled containment atmosphere must be used for all pneumatic applications within containment; and

C. No potential sources of air and oxygen may be present other than radiolysis of reactor coolant.

The amount of oxygen that could be expected to be introduced into the containment shall not cause the containment to become deinerted within the first 30 days after an accident.

The system originally designed for combustible gas control was the atmospheric containment atmosphere dilution (ACAD) system, which used standard air to dilute the containment and thereby reduce the hydrogen concentration. Since it represents an oxygen source contrary to the guidelines of Generic Letter 84-09 and a threat in dealing with accidents beyond the DBA, the ACAD air dilution capability has been disabled and injection piping and pressure bleed subsystem piping has been cut and capped.

The primary means for combustible gas control is the inerted containment. The NCAD system has been installed to provide a redundant path and single failure proof means of re-inerting the containment with nitrogen following a LOCA.

6.2.5.2 Design Bases

The combustible gas control systems are designed to prevent the formation of a combustible gas mixture in the primary containment. This is a redundant safety measure since the highly reliable emergency core cooling system (ECCS) provides sufficient cooling during a LOCA to inhibit formation of hydrogen by a metal-water reaction, the primary containment can accommodate an energy addition equivalent to the combustion of hydrogen formed during postulated accidents, and the containment is inerted.

The design bases for combustible gas control are as follows:

A. To maintain the drywell in a nitrogen inerted condition as a means of inhibiting the formation of a combustible gas mixture under LOCA conditions;

B. To monitor radiation, hydrogen, and oxygen levels within the primary containment; and

C. To provide a means to dilute the primary containment atmosphere with nitrogen under LOCA conditions if a potentially combustible gas mixture were to develop.

Since the NCAD system is now installed, the ACAD system has been disabled to prevent it from operating and eliminate it as a potential post-accident oxygen source in order to satisfy the criteria of Generic Letter 84-09. The ACAD injection piping and pressure bleed subsystem piping has been cut and capped and the solenoids to the air operated isolation valves have been electrically disconnected.

Following are the criteria used to design the nitrogen containment atmosphere dilution (NCAD)/containment atmosphere monitoring (CAM) system:

A. The systems are designed in accordance with guidelines contained in Branch Technical Position CSB 6-2, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident."[38] This system was also designed in accordance with General Design Criteria 41, 42, 43, 54, and 56 of 10 CFR 50, Appendix A.[39]

B. In postulating the occurrence of metal-water reaction, a penetration of the oxide layer 0.00023 inches into the cladding was assumed, and the core was assumed to consist of 8x8 fuel assemblies. This assumption is representative of the 7x7 configuration or any combination between the 7x7 and 8x8 assemblies. The generation of hydrogen from metal-water reaction was assumed to evolve over a 2-minute period at a constant reaction rate. The resulting hydrogen was assumed to be uniformly distributed in the drywell, as recommended by Branch Technical Position CSB 6-2.[38]

C. The systems have the capability of sampling and measuring the hydrogen and oxygen concentration throughout the drywell or torus during all modes of operation.

D. The systems have the capability of controlling combustible gas concentrations in the drywell and torus atmospheres with a minimum release of radioactive material to the environment.

E. The systems will not introduce safety problems that affect containment integrity.

F. As a backup to the combustible gas control system, capability is provided to control gas concentrations by purging the drywell and torus atmospheres via the Standby Gas Treatment System (SBGT).

G. An appropriate margin between the hydrogen concentration limit and the hydrogen concentration at which action occurs is provided. This margin is based on the simplicity of the system and the start-up actions required.

Following are design bases for post accident design of the NCAD System:

A. The NCAD system is to provide a redundant path, single failure proof means of reinerting the containment following a LOCA.

B. The NCAD system must be capable of being initiated 19 hours after the accident, and provide a maximum required flow rate of approximately 29 scfm of nitrogen against a maximum containment backpressure of 31 psig.

C. The nitrogen supply system including the inerting pathways upstream of the Containment Isolation Valves are not required to be safety related.

D. Accessibility for operator action to initiate the NCAD system post LOCA must be assured.

6.2.5.3 System Design

6.2.5.3.1 Vent, Purge, and Inerting System

Containment isolation criteria are met by isolation valves in each system which close on isolation signals from the primary containment isolation system. The ACAD system isolation valves have been removed and piping capped as part of ACAD abandonments. Containment Isolation is discussed in Section 7.3 and Section 6.2.4.

The oxygen sampling system automatically draws samples of the containment atmosphere at various elevations, analyzes the sample oxygen content, and indicates and records the results continuously in the control room. Oxygen sample concentration is also indicated at the drywell personnel airlock entrance. Low-purge supply temperature, high-supply line pressure, high-oxygen content, and low-sample flow alarms are annunciated in the control room.

Primary containment venting to reduce drywell pressure and purging to reduce containment oxygen concentration are conducted in accordance with established operating procedures. During startup, shutdown and normal operation venting and purging are accomplished via either the standby gas treatment system and plant chimney, or the reactor building ventilation stack, depending upon sample analysis results.

Containment venting is also discussed in Section 6.2.1.2.7. Venting through the augmented primary containment vent system (APCVS) is discussed in Section 6.2.7.

6.2.5.3.2 Containment Atmosphere Monitoring System

In the event of a major LOCA, generation of hydrogen and oxygen gases may take place at such rates that a combustible gas mixture could be produced. To assure containment integrity is not endangered due to the possible ignition and combustion of the gas mixture, the NCAD system and the containment atmosphere monitoring (CAM) system are provided for controlling the relative concentrations of hydrogen and oxygen to below combustible mixture levels. The control of gas concentrations following a LOCA is accomplished by diluting the evolved oxygen with (CAD) or nitrogen (NCAD) if required. The resulting pressure increase in the containment is controlled to well below the design pressure by intermittent bleeding of the containment atmosphere into the SBGTS. As a backup means of control, the containment atmosphere can be purged.

This protection supplements that provided by the emergency core cooling systems and nitrogen inerting system.

The concentration of combustible gases in the containment following a LOCA is monitored by the CAM system. The CAM system is safety-related and is designed such that all components are Seismic Category I and all active components are redundant. Separate power buses are used for the redundant channels of the CAM system. All equipment associated with the CAM sample loop and sensors is located within the reactor building, which is a Seismic Category I structure. The NCAD system is redundant path and single failure proof.

The CAM system consists of redundant hydrogen, oxygen, and radiation monitoring subsystems. The entire monitoring system is automatically activated upon the occurrence of a LOCA through core spray system initiation logic (analytical limits: 59 inches reactor water level or +2 psig drywell pressure). The system may also be manually initiated from the control room using a keylock switch. The system remains on at all times after initiation, unless turned off with a keyswitch.

Hydrogen and oxygen concentrations within containment are determined by taking gas samples from the torus and drywell, routing the sample to the gas monitors, and returning the sample to the drywell thereby forming a closed loop system. The system is seismically Category I and environmentally qualified. The CAM system is designed in accordance with NRC Standard Review Plan 6.2.4.II.3.e. It is safety-related and built to ASME Section III, Class 2 code requirements. The system is qualified to IEEE 323-1974 and IEEE 344-1975.

The philosophy for the design of the system is to continuously return the gas samples to the containment rather than to isolate the system from containment under LOCA conditions. Therefore, this system is designed as an extension of the containment during an accident.

As shown in Drawing M-706, Sheets 1and 2, the system is completely redundant and separated into engineered safety features (ESF) Divisions I and II. There are four intake ports on each of the two headers in containment. The intake ports on each header are located at four elevations (three in the drywell, one in the torus) approximately equidistant from each other. The headers are on opposite sides of the reactor. A globe valve is installed on each intake port to allow throttling. These valves are set to provide approximately equal flow into each intake port. There are no obstructions which would prevent hydrogen from reaching the intake ports quickly.

Since there are two monitors per unit, a single active failure of the hydrogen monitoring system can be accommodated.

The CAM system is designed to operate under the conditions described in Section 3.11.

THIS PAGE INTENTIONALLY LEFT BLANK

6.2.5.3.3 Nitrogen Containment Atmospheric Dilution (NCAD) System

In the event of a LOCA, combustible gas concentrations may require the addition of nitrogen to the Containment. The NCAD system is designed to be initiated at 19 hours after a LOCA, when the oxygen concentration may reach 5 percent by volume (see Section 6.2.5.4.2.2).

In addition to the normal inerting and makeup pathways, two bypass lines are provided for each unit. These bypass lines are routed from the discharge of the makeup line atmospheric vaporizer, located outside, to the downstream side of the pressure regulating stations in the normal inerting and makeup pathways, located within the Reactor Building. These lines provide the capability of inerting the Containment post-LOCA.

The NCAD system nitrogen flow is initiated through either or both of the bypass lines by opening the manual isolation valve located outside in the vicinity of the Nitrogen Supply system equipment, and opening the Containment isolation valves from the control room.

The NCAD system is designed to inject a maximum required flowrate of approximately 29 scfm of nitrogen to the Containment, considering a maximum backpressure of 1/2 of the Containment design pressure, or 31 psig.

6.2.5.3.4 Containment Post Accident Vent Path (Historical)

One of the available post accident containment vent paths was originally designed as the ACAD pressure bleed subsystem.

The ACAD pressure bleed subsystems were disabled and the piping permanently cut and capped as part of ACAD abandonments.

6.2.5.4 Design Evaluation

In evaluating the combustible gas control system design, it was necessary to consider the following:

A. The production and accumulation of combustible gases within the drywell and torus following the postulated LOCA;

B. The capability of the system to reduce combustible gas concentrations within containment;

C. The radiological impact of operation; and

D. The capability to mix the combustible gases within the containment atmosphere and prevent high concentrations of combustible gases in local areas.

6.2.5.4.1 Historical Short- and Long-Term Hydrogen Generation

In the period immediately after LOCA, hydrogen would be generated by both radiolysis and metal-water reaction. However, in evaluating short-term hydrogen generation, the contribution from radiolysis is small in comparison with the hydrogen generated by a postulated metal-water reaction. Refer to Section 6.2.1.3.7 for a detailed discussion of the sources of hydrogen in the containment.

In accordance with the provisions of the Branch Technical Position CSB 6-2,[38] the amount of hydrogen assumed to be generated by metal-water reaction in establishing combustible gas control system performance requirements was based on the amount calculated in demonstrating compliance with 10 CFR 50.46.[40]

As described in NEDO-20566[31] GE submitted two alternate methods for the calculation of core wide metal-water reaction.

The first method of analysis for core-wide hydrogen generation utilizes the heatup code CHASTE in a series of calculations. The calculations for planar segments are made with varying values of segment power to represent all feasible segment powers for a particular core. The calculated temperature responses are used to predict the amount of cladding reacted locally for each planar segment. The local cladding reactions are weighted by a conservative core axial power distribution and summed to calculate the total core-wide cladding reacted. The core axial power distribution is based upon fine noding of operating reactor data and is conservative since it is relatively flat. The total cladding reacted is divided by the total cladding surrounding the active fuel. The quotient is the percentage of core-wide hydrogen generation.

The second method of analysis, documented in NEDO-11013-77,[42] develops a relationship between core-wide metal-water reaction and peak clad temperature, based on a core model which has power and temperature distributions which conservatively bound those calculated for BWRs.

Both of the methods described above have been found acceptable by the NRC staff; however, the second method has been used in Appendix K submittals. The metal-water reaction fraction calculated utilizing the second method, because of the simplifications made in formulating that model, renders a number which is higher by a factor of approximately 4 than the result of the preliminary calculations utilizing the first method.

The result obtained from this core-wide metal-water reaction calculation is 0.21%. In accordance with the provision of Branch Technical Position CSB 6-2, the core-wide metal-water reaction calculated, in compliance with 10 CFR 50.46 (0.21%), is multiplied by a factor of 5. This results in a metal-water reaction fraction of 1.05%. This metal-water reaction fraction is greater than the metal-water reaction fraction which results from postulating a reaction of all the metal in the outside surface of the cladding cylinders surrounding the fuel (excluding the cladding surrounding the plenum volume) to a depth of 0.00023 inches. This calculated metal-water reaction fraction, 1.05%, was therefore used as input into the computer program CONCEN. The computer program CONCEN is described in Reference 6.

The 0.21% metal-water reaction was calculated based on an all 7x7 core and, therefore, the zirconium inventory was based on a 7x7 core. The 8x8 core was not used because a 7x7 core rendered a more restrictive core-wide metal-water reaction.

It has been shown that the amount of 9x9 fuel element cladding which reacts chemically with water or steam does not exceed 1.0% of the total amount of zircaloy in the reactor. Refer to Section 6.3 for a complete description of the current LOCA analyses. Refer to Section 6.2.1.3.7 for a description of the containment's capability with respect to hydrogen generation.

The generation of hydrogen due to radiolysis begins immediately after the LOCA. The guidelines contained in Branch Technical Position CSB 6-2[38] have been followed to determine hydrogen generation rates. The details of modeling and the input variables used are described in Section A.2.1.2. and Section A.3 of Reference 6.

6.2.5.4.1.2 Current Hydrogen Generation From Metal-Water Reaction

GE 14 fuel was evaluated, in accordance with Regulatory Guide 1.7 for the purposes of verifying a non-explosive hydrogen mixture in the containment post-LOCA. Results of that evaluation showed core wide metal water reaction results of less than 0.945% volumetric hydrogen concentration, which is the basis for hydrogen generation in the post LOCA containment atmosphere flammability evaluation in Section 6.2.5.4.2.2.

SVEA-96 Optima2 fuel is evaluated in accordance with Regulatory Guide 1.7 for the purpose of verifying a non-explosive hydrogen mixture in containment post-LOCA. Results of that evaluation show core-wide metal-water reaction results of 4.00% volumetric hydrogen concentration based on five times the maximum amount of core wide oxidation calculated in accordance with 10 CFR 50.46[75]. The resulting Hydrogen would not lead to an explosive mixture in the containment post-LOCA.

Although this value is greater than that reported for GE14 fuel, neither fuel type nor amount of hydrogen generation due to metal-water reaction affects the production rate of oxygen, which is the controlling factor in maintaining a non-flammable containment atmosphere. It is therefore concluded that differences in the amount of cladding oxidized for the different fuel designs will not adversely impact the conclusions of the combustible gas analysis.

An additional consideration with regard to the NCAD analysis is that the primary influence on the nitrogen addition rate is the radiolytic generation of oxygen. The fuel type or extent of hydrogen generation due to metal-water reaction has no impact on the rate of production of oxygen. Since the analysis is primarily focused on maintaining oxygen concentrations below 5%, slight increases in the hydrogen generation due to metal water reaction would actually reduce the oxygen fraction, which would be conservative.

6.2.5.4.2 Reduction of Containment Combustible Gas Concentrations

THIS PAGE INTENTIONALLY LEFT BLANK

6.2.5.4.2.2 Analysis of Combustible Gas Control Using Nitrogen Dilution

An analysis of the use of nitrogen dilution to control post-LOCA containment combustible gas concentrations has been performed. The study was based on NRC Regulatory Guide 1.7 assumptions for radiolytic oxygen and hydrogen generation following a design basis LOCA, and upon a conservatively determined initial oxygen and nitrogen content inside containment.

The major analysis assumptions and methodology were consistent with the NRC combustible gas control Standard Review Plan 6.2.5 and Regulatory Guide 1.7. In addition, the analysis assumed that good mixing occurs in the containment and that containment leakage is 1% per day.

Major containment parameters and initial conditions used in this analysis are summarized below:

Core thermal power (102% rated)	3016 MWt
Drywell free volume	158,236 ft^3
Suppression chamber free volume	112,800 ft^3
Drywell temperature	150°F
Drywell pressure	15.7 psia
Drywell relative humidity	100%

Drywell oxygen concentration	4% by vol
Suppression chamber temperature	98°F
Suppression chamber pressure	14.7 psia
Suppression chamber relative humidity	100%
Suppression chamber oxygen concentration	4% by vol

The amount of pre-accident gases in the containment increases with increasing initial containment pressure and decreases with increasing initial containment temperature. The containment initial conditions selected for the analysis were selected to minimize the calculated initial gas amount and the time to reach a flammable concentration and maximize the calculated nitrogen addition.

The analysis led to the following conclusions:

A. The containment would reach 5% oxygen by volume about 19 hours after the postulated LOCA.

B. To maintain the oxygen concentration at exactly 5% by volume up to 7 days after the LOCA, 393 lb. moles of nitrogen (141,000 standard ft^3) would have to be added at a time-dependent rate starting at 29 scfm at 19 hours after the accident, reducing to 11.5 scfm at 7 days, and further reducing to 5.2 scfm at 32 days when the pressure is calculated to reach the regulatory limit of 31 psig.

C. If nitrogen were added to the containment at a rate that just maintains the oxygen at 5% by volume, the containment pressure would reach the 10 CFR 50.44 limit (one-half of the design pressure or 31 psig) in about 32 days using Regulatory Guide 1.7 assumptions and assuming 1% leakage.

D. At 30 days, a total of 393,000 standard ft^3 of nitrogen would have been added.

E. Nitrogen dilution can control the containment combustible gas composition without venting for at least 30 days if the conservative generation rates of Regulatory Guide 1.7 are used.

6.2.5.4.3 <u>Original Analysis of Radiological Impact of ACAD System Operation</u>
(This section contains historical information regarding ACAD system operation. The ACAD system is no longer operational.)

As a result of ACAD system operation, some releases of radioactivity to the environment are necessary. Consequently, the total dose resulting from a LOCA is increased by the incremental amount resulting from these releases. The LOCA-related doses are described in Section 15.6.5.5.1.

As was discussed in the previous subsection, the pressure bleed subsystem would be used to release containment atmosphere into the SBGTS 116 hours after the LOCA and continues to release radioactive materials intermittently for the remainder of the assumed duration of the accident.

The dose calculation method used employed the actual site meteorology to calculate the diffusion parameters. The diffusion parameters (χ/Q) were calculated using the sector average, Gaussian diffusion equation for an evaluated release as described in Appendix A to Quad Cities FSAR (Dockets 50-254 and 50-265). Values were determined for the low population distance of 5 miles. The 1974 one-year period of site data was used. Cumulative probability of exceeding a certain dose during a year was determined assuming that the accident occurs every hour of the year and lasts for 30 days. The proprietary code METPER was employed for this calculation.

The model for estimating the probability of an individual receiving an integrated dose in excess of a given amount resulting from the containment venting utilizes long periods of hourly weather measurements to simulate sequences of atmospheric diffusion conditions over a given time period following the postulated accident. These sequences are coupled with a postulated accident which might occur at any random time. The METPER program computes the integrated offsite whole body and thyroid doses over a selected time period (or window). The processing begins for the selected window starting with the first hour of χ/Q record being used and continues until the integrated dose over the selected window is complete. The process is then repeated for the same elapsed time period (window) starting a new integrating period with each subsequent hour of χ/Q data. In this process, an integrated dose over the given period has been computed effectively assuming that an accident has occurred during each hour of the year. The period length selected for the purposes of this analysis is 720 hours. Assuming that there were 8760 integrated 720-hour doses for each location being investigated, the probability of an individual at any one of these locations receiving a given dose (or greater) is determined by dividing the total number of occurrences of each dose (or greater) at this location by the total number of integration periods. The cumulative probability distribution is computed by finding the total occurrences of doses equal to or in excess of sequentially smaller doses regardless of direction. The distribution represents the chance that any person at any location along the low population distance boundary would receive an exposure equal to or greater than the indicated dose.

The results of this analysis are shown on Figures 6.2-57 and 6.2-58, where the probabilities of exceeding certain thyroid or whole body doses are plotted. Table 6.2-12 summarizes the results of the analysis by showing the 5% probable thyroid and whole body doses. These doses, when added to the doses calculated for the LOCA by the NRC staff,[44,45] are well below the 10 CFR 100 limits. For use with Alternative Source Term (AST), new χ/Q values were calculated as describe in Chapter 2. These new χ/Q were used in the AST analyses. Results doses are below the 10 CFR 50.67 limits.

Utilizing the Regulatory Guide 1.3[46] assumptions and meteorology (which is a more conservative approach than using the actual site meteorology) and the METPER code, the incremental doses resulting from the ACAD system operation are listed in Table 6.2-12.

In the absence of the ACAD system, the 4% hydrogen concentration is reached approximately 240 minutes (4 hours) after a LOCA. Containment inerting is used to preclude a flammable mixture of oxygen and hydrogen immediately after the completion of the metal-water reaction. Based on the above discussion, it is concluded that the ACAD system operation meets the dose criteria of Branch Technical Position CSB 6-2.[38]

6.2.5.4.4 Atmosphere Mixing in Containment

The capability to mix the combustible gases within the containment atmosphere and thus prevent high concentrations of combustible gases in local areas inherently exists in the containment.

The variations in concentrations of hydrogen throughout the drywell would be expected to be minimal, i.e., less than 0.1%, due to the convective currents present in the drywell during the post-LOCA period.

The containment systems experiments (CSE) performed by Battelle Northwest Laboratory[47-50] and the Carolina Virginia Tube Reactor (CVTR) experiments[51,52] performed by the then Idaho Nuclear Corporation both provided data which showed substantial convective currents were produced by the LOCA and then sustained for a prolonged period of time after blowdown ceased.

Hydrogen released to the torus is from a relatively weak and dispersed source, i.e., radiolysis in the suppression pool. Since the suppression pool is being heated during this period, fairly large temperature gradients between it and the torus atmosphere exist. This temperature difference promotes natural convection, which in turn promotes good mixing.

Other experiments[53,54] have shown that when a gas that is lighter than air is introduced at the bottom of a container, very rapid mixing occurs.

Based on the above discussion it is concluded that hydrogen generated from metal-water reaction and radiolysis in the drywell and torus would mix homogeneously with the volumes' atmosphere, and therefore no localized high gas concentrations would be expected.

6.2.5.5 Instrumentation and Controls

The purpose of the CAM system instrumentation and control is to provide the signals necessary to indicate and alarm high hydrogen, high oxygen or high gross gamma radiation levels in the containment following a LOCA. The gross gamma monitoring subsystem monitors the dose rate resulting from gross release of fission products from the fuel. The hydrogen and gross gamma monitoring subsystems consist of duplicate channels; each channel provides a local measurement in both areas and transmits the signal to the control room where a permanent record is provided on recorders.

6.2.5.5.1 Hydrogen Monitoring Initiating Circuits

This system consists of a hydrogen sensor, an electronics assembly and a recorder. The monitors are located in the reactor building on the first floor.

The hydrogen sensor provides a signal proportional to the hydrogen partial pressure of the drywell and torus. This signal is then divided by a signal equal to the containment pressure. A signal is produced that is proportional to the volume percent of a hydrogen in the containment, thus:

$$\frac{H_2 \text{ Partial Pressure}}{\text{Total Pressure}} = \% \, H_2$$

The sensor output is directed to control room panels 902(3)-55 and 902(3)-56, and is indicated on SPAN meters and a recorder. A range of 0 - 10% is provided.

6.2.5.5.2 Radiation Monitoring Initiating Circuits

The radioactivity monitoring subsystem employs two sensors, mounted within the drywell.

Each instrument channel consists of a gamma-sensitive ion chamber high range radiation monitor. One upscale trip circuit is used to initiate an alarm on high radiation. The second circuit is a downscale trip that actuates an instrument trouble alarm in the control room. The output from each high range radiation monitor is displayed on an eight-decade meter in the control room. The detector covers the range of 10^0 to 10^8 R/hr. Two 2-pen strip chart recorders are also located in the control room. One channel of each strip chart has been abandoned in place. When activated, the trip circuit for each monitoring channel is energized. When power to monitoring components is interrupted, a trip signal results.

6.2.5.6 Tests and Inspections

6.2.5.6.1 Hydrogen/Oxygen Monitor Tests

The CAM hydrogen monitors and oxygen monitors are periodically calibrated and functionally tested. Calibration gas bottles are mounted locally adjacent to the associated hydrogen/oxygen monitor cabinets on the first floor of the reactor building. An instrument check is performed once per 31 days, and a calibration is performed once every 3 months.

6.2.5.6.2 Oxygen Analyzer Test

The containment oxygen analyzing system is functionally tested once per week and is calibrated once per six month period.

6.2.5.6.3 Radiation Monitoring Test

A built-in simulated source (an adjustable current) is provided with each radiation monitor for test purposes. In addition the operability of each monitoring channel can be verified by comparing the outputs of the channels at any time.

Each drywell radiation monitor is calibrated once every refueling outage and an instrument check is performed once per 31 days.

6.2.5.6.4 Deleted

6.2.5.6.5 Pressure Bleed Subsystem Test

Testing of the containment vent path air operated valves is done through remote manual switches located in the main control panels.

6.2.5.6.6 Containment Isolation Valve Leak Test

Test connections are provided between the first and second isolation valves for leak tests of the containment isolation valves.

6.2.5.6.7 Containment Atmosphere Monitor Subsystem Test

Since the CAM is activated during an accident, the entire closed loop of the CAM is subjected to drywell pressure. Thus, leak rate testing of the CAM includes all piping outside the containment isolation valves, the analyzer cabinet, and the CAM drywell return line check valve.

6.2.6 Containment Leakage Testing

The Primary Containment Leakage Rate Testing Program was developed to provide assurance that the primary containment, including those systems and components which penetrate the primary containment, does not exceed the allowable leakage rate values specified in the Technical Specifications and bases. The allowable leakage rate is determined so that the leakage rate assumed in the safety analysis is not exceeded. This program meets the requirements of Regulatory Guide 1.163, Performance-Bases Containment Leak-Test Program and 10 CFR 50, Appendix J.

The program for testing the primary containment system includes an integrated leak rate test (ILRT) of the containment and local leakage rate tests (LLRTs) of containment penetrations and containment isolation valves.

6.2.6.1 Containment Integrated Leakage Rate Test

Following construction of the drywell and suppression chamber, each was pressure tested at 1.15 times its design pressure. Penetrations were sealed with welded end caps. Following the strength test, the drywell and suppression chamber were tested for leakage rate at design pressure; each met the leakage criterion for that stage of construction of less than 0.5% per day at design pressure. The suppression chamber was also tested while half-filled with water to simulate operating conditions.

After complete installation of all penetrations, an integrated leakage rate test of the drywell, suppression chamber, and associated penetrations was conducted. The tests were conducted at several test pressures to establish a leakage rate curve. The necessary temporary instrumentation was installed in the containment systems to provide the data to calculate the leakage rate.

The design basis accident (DBA) used for determination of allowable containment leakage rates was the loss-of-coolant accident (LOCA) as discussed in Section 6.2.1.3.5.1 and Section 15.6.5. The initial containment conditions, containment pressure transient, percent metal-water reaction, and fission product release to the containment assumed for the double-ended recirculation line break were used in this analysis. In addition, the emergency ventilation system was assumed operative such that any fission products which leaked from the primary containment would pass through filters prior to discharge to the environment via the chimney.

Containment leakage rate tests, including Types A, B, and C tests as defined in 10 CFR 50, Appendix J, are performed in accordance with the requirements of the Technical Specifications. These requirements conform to the requirements of 10 CFR 50, Appendix J, with the exception of several NRC-authorized exemptions.

An exemption from Appendix J requirements for containment isolation valve leakage rate tests (Type C tests) permits Type C tests to be performed prior to the ILRT (Type A test) and the results of the Type A test to be back-corrected to simulate the as-found conditions using the results of the Type C tests provided that:

A. When performing Type C tests, the conservative assumption that all measured leakage is in a direction out of the containment is applied, unless the test is performed by pressurizing between the isolation valves; and

B. When performing Type C tests by pressurizing between the isolation valves, the conservative assumption that two valves leak equally is applied (and therefore one-half of the measured leakage is in a direction out of the containment), when the isolation valves are shut by normal operation without preliminary exercising or adjustment.

Type C tests for instrument line manual isolation valves installed in accordance with Regulatory Guide 1.11, "Instrument Lines Penetrating Primary Containment," are not required provided that the subject instrument lines are not isolated from the containment atmosphere during performance of a Type A test.

Due to the design of the two-ply containment penetration expansion bellows, it has been determined that the bellows cannot be properly tested to satisfy Appendix J, Type B testing requirements. Accordingly, a testing and replacement program for the bellows assemblies has been accepted by the NRC as an acceptable alternative to the testing requirement, and an exemption from Appendix J has been granted for these assemblies. Each assembly is individually exempted until it is replaced by a testable bellows assembly at which time the testable assembly will be tested in accordance with the normal Type B test program. Similarly, if a method is developed which ensures a valid Type B test on one or more assemblies, those bellows will also be excluded from the exemption and will be required to be tested in accordance with the normal Type B test program.

The periodic ILRT is conducted at a test pressure of 43.9 psig which corresponds to the calculated maximum peak accident pressure. The test is conducted in accordance with the provisions of ANSI /ANS-56.8-1994. During testing, the initial pressure is maintained much longer than the few seconds for which the peak accident pressure is expected to be sustained (see Figure 6.2-19). Testing with the peak accident pressure is also conservative because the airborne fission product inventory is negligible for the short time (after the initial blowdown) during which the peak pressure occurs.

The ILRT is performed at a frequency specified in the Primary Containment Leakage Rate Testing Program based on maintaining the primary containment leakage rate below the permissible leakage rate limit. An integrated test with a leakage rate above the permissible leakage rate limit requires identification of the cause of unacceptable performance and determination of corrective action. Once computed, the test interval shall be at a frequency specified in NEI 94-01, Rev.0.

6.2.6.2 Containment Penetration Leakage Rate Test

The pre- and post-operational testing of the penetrations include testing of the piping and electrical penetrations, access openings, and flanged openings.

Containment penetrations and seals are tested in accordance with the Primary Containment Leakage Rate Testing Program. Testing is conducted using either of two methods: measuring the decay rate of a given volume with no replacement gas, or, more commonly, measuring the flowrate of replacement gas at a constant pressure. The testing is conducted at a pressure not less than 48 psig which is sufficient to verify the ability of the penetrations to withstand the peak containment pressure as a result of a LOCA, as well as to verify the ability of the penetrations to maintain overall containment leakage within acceptable limits. These tests were performed prior to initial startup and subsequent tests are performed on a regular basis.

The personnel access lock is provided with double doors, which open inward, toward the drywell and are designed to withstand a large outward force due to a high drywell internal pressure. The doors are not designed to withstand a large inward force due to a differential pressure in the reverse direction. Therefore, the leakage rate testing for the access lock requires placing a strongback on the inner door prior to pressurizing the space between the doors to 48 psig. Testing is conducted on a regular basis.

Type B tests of the containment airlocks are performed at pressures and intervals specified in the Primary Containment Leakage Rate Testing Program. In addition, a 43.9 psig test is performed when primary containment is required following an airlock opening. The intent of the requirement is to ensure that the airlock door seal integrity is maintained and that no degradation has occurred as a result of opening the airlock.

Flanged openings are provided with double seals and test ports so that the space between the seals can be pressurized to test for leakage. Testing is conducted on a regular basis, or after seal maintenance. If a flange is to be opened thereby breaking the seal, the seal is tested first in the as found condition before the flange is opened, in accordance with (10 CFR 50, Appendix J, and then again when the flange is closed, in accordance with the Primary Containment Leakage Rate Testing Program.

The major portion of leakage from the containment has been shown at Humboldt Bay and other nuclear power stations[55-58] to come primarily from valves and penetrations. Little or no leakage is attributable to the containment shell.

Shell leakage (including leakage through nonisolatable lines and seals) can be determined by conducting both an ILRT and LLRTs and subtracting the results of the LLRTs from that of the ILRT. (For valves in a series, only the LLRT result of the valve with the lowest leakage rate is subtracted.) A calculated value for integrated leakage can be subsequently obtained by adding the results of later LLRTs (performed more frequently than the ILRT) to the most recent value for shell leakage.

6.2.6.3 Containment Isolation Valve Leakage Rate Test

The pre- and post-operational testing of the primary containment isolation valves includes pressure testing, leakage testing, and operability testing. Isolation valves tested include those valves in lines connecting to the open space within the containment vessels and valves in lines connected to the reactor coolant system. Local leakage rate testing of the volume between containment isolation valves (Type C test) is conducted at the calculated maximum peak accident pressure of 48 psig with one exception: the volume between the main steam isolation valves (MSIVs) is tested at 25 psig. Testing is conducted on a regular basis.

Type C testing of the MSIVs at the reduced pressure of 25 psig instead of the 43.9 psig required by 10 CFR 50, Appendix J has been authorized by the NRC. The leakage rate acceptance criterion for the MSIVs at 25 psig test pressure is a total maximum pathway leakage for all MSIVs of $\leq$46 scfh. The leakage rate measured at 25 psig is corrected mathematically to a leakage rate at 43.9 psig. The reason for the reduced test pressure is that the inboard MSIV is tested with pressure acting in the reverse direction to that encountered in a LOCA situation. The MSIV is designed such that it is held closed by a combination of the spring force, air cylinder closing force, and upstream line pressure. During the leakage rate test there is no upstream pressure. Any downstream pressure greater than 25 psig would tend to lift the MSIV disk off the seat, giving an inaccurate leakage rate measurement. Refer to Section 6.2.4.2.2 for a description of the MSIVs.

Test taps are located between the MSIVs to permit leakage testing while the reactor is in a cold shutdown condition by pressurizing the enclosed space between the valves.

The sum of the leakage rates determined from the individual tests of those isolation valves in lines open to the free space of the containment is added to the total leakage rate of the penetrations and access openings alone.

Isolation valves in lines which form a closed loop, either within the containment vessels or outside the containment, were not required to be separately leak tested, but their performance was carefully observed during initial system acceptance tests. At each major refueling, these systems are operated at normal operating pressure and their leakage observed.

6.2.7 Augmented Primary Containment Vent System

The purpose of the augmented primary containment vent system (APCVS) is to vent the primary containment only as directed by the Dresden Emergency Operating Procedures (DEOPs).

The APCVS is designed to prevent containment pressure from exceeding the Primary Containment Pressure Limit (PCPL), as defined in the DEOPs, in the highly unlikely event of a transient requiring reactor shutdown followed by a complete and sustained failure of decay heat removal capability. This scenario has been labeled the TW sequence in the station probabilistic risk assessment (PRA). The APCVS provides a direct vent path from the pressure suppression chamber or from the pressure suppression chamber and the drywell to the chimney. This containment emergency vent path will prevent a containment breach with the subsequent uncontrolled radioactivity release.

The APCVS may also be utilitized for venting primary containment, as directed by the DEOPs, for combustible gas control. Use of the APCVS for combustible gas control is authorized only after the primary containment hydrogen and oxygen concentrations have exceeded the deflagration limits as defined in the DEOPs. The APCVS is utilized to reduce the primary containment pressure below the operational pressure limit of the SBGT system. The APCVS could also be utilized to rapidly vent and purge the primary containment with air, but only if nitrogen makeup and NCAD are unable to reduce the concentration of one or both of the explosive constituents, either hydrogen or oxygen, below the respective deflagration limits.

6.2.7.1 Design Basis

The APCVS is designed to prevent containment pressure from exceeding the PCPL. The system is nonsafety-related but seismically supported.

The design assumes a maximum pressure of 62 psig, measured at the bottom of the pressure suppression chamber coincident with a maximum water level in the pressure suppression chamber.

The vent is sized such that, under conditions of constant heat input at a rate equal to 1% of rated thermal power and containment pressure equal to the PCPL, the exhaust flow through the vent (78,910 lb/hr) is sufficient to prevent the containment pressure from increasing. This vent is capable of operating up to the PCPL.

The APCVS piping, also referred to as the hardened vent path, is capable of withstanding, without loss of functional capability, expected venting conditions associated with the TW sequence. The design is such that the APCVS will not create a combustible gas mixture through introduction of air.

6.2.7.2 System Description

The APCVS is comprised of piping, round duct, square duct, air-operated valves, and the associated electrical components for operation and indication. The air-operated valves each have an accumulator for storage of compressed air in the event of a loss of instrument air. The system piping is shown in Figures 6.2-59 and 6.2-60.

The piping interfaces with the suppression chamber main exhaust and the drywell main exhaust lines. It is routed through the reactor building into the turbine building via an 18-inch diameter vent and purge duct. The APCVS vent valve, AO-1601-92, is located in a 10-inch diameter branch line connected upstream of the vent and purge system prefilters. This 10-inch line is routed below the turbine building roof above the Unit 3 turbine, passes through the turbine building wall below the radwaste building roof, is routed under the radwaste building roof, penetrates the exterior wall, and ties into the radwaste ventilation exhaust duct which flows to the chimney. A description of normal containment venting is included in Section 6.2.1.2.7. Refer to Section 6.2.5.3.1 for a description of the vent, purge, and inerting system.

The APCVS controls are located in the main control room. The APCVS mode switch, three keylock containment isolation valve (CIV) override switches, and valve control switches are located on the 902(3)-3 panel. Annunciation for the APCVS mode switch position and CIV override is also on the 902(3)-3 panel.

Initiation of the APCVS requires multiple, deliberate operator actions. The APCVS mode switch is a two-position switch which is administratively controlled. In the APCV position this switch's only active function is to close valves AO-1601-91 and AO-1601-63 (if they are not already in the closed position). These valves isolate the vent and purge system prefilters and standby gas treatment system. The APCVS mode switch also provides a permissive for valve AO-1601-92 to be opened and a permissive to override the Group 2 primary containment isolation signal for valves AO-1601-60, -23, and -24 in conjunction with their respective keylock switches. The primary containment isolation logic system is discussed in Section 7.3.2. A description of the primary containment isolation valves is included in Section 6.2.4.

6.2.7.3 Safety Evaluation

Operation of the APCVS will be required as directed by the DEOPs only in the event of a TW sequence or other event such that primary containment pressure might exceed the PCPL or for combustible gas control. These postulated events are beyond the design basis of the plant.

The APCVS has no active functions during normal plant operation or design basis events. The only required function under normal operating conditions is that the valves, except for the normally open 18-inch vent and purge prefilter isolation valve, remain in their closed position to allow reactor building ventilation operation and provide chimney isolation.

The APCVS was installed in response to Generic Letter 89-16. Although not a part of the commitment, the APCVS also provides the capability to vent the drywell if conditions such as high suppression chamber water level prevent suppression chamber venting. To take advantage of the scrubbing effect of the suppression pool, the selected vent path will normally be from the pressure suppression chamber only.

Existing radiation monitoring capability in the chimney will alert control room operators of radioactivity release during venting.

Because Dresden is a dual unit station, the Unit 2 and Unit 3 APCVSs are crosstied, and a common line directs the effluent of both units to the chimney. It is not postulated that simultaneous TW sequences and/or LOCAs in both units would require simultaneous venting of both units. Although extremely unlikely, simultaneous venting of both units is precluded administratively, through procedures and communication between units. Venting from one unit does not compromise the safety of the other unit. System design precludes backflow from the venting unit to the other unit.

Subsequent venting sequences are controlled by closing and opening the APCVS vent valve until decay heat removal capability is reestablished or until it is assured that primary containment pressure will not exceed PCPL. In the event that both units were to require venting at the same time, both units could be vented by alternating the vent path from one unit to the second unit and back again as necessary.

6.2.8 References

1. Bodega Bay Preliminary Hazards Summary Report, Appendix 1, Docket 50-205, December 28, 1962.

2. Robert Harrington, Rubber Age 82461 (December 1967).

3. Schollenberger, C.S. et al., "Polyurethane Gamma Radiation Resistance," B.F. Goodrich Co. Research Center, Nobs - 72419 (June 1, 1959).

4. Kircher, J.F. and R.E. Bowman, "Effects of Radiation on Materials & Components."

5. Modifications M12-2-81-32, M12-2-82-8, M12-3-79-55, M12-3-82-8.

6. DVR D12-2-88-137, Heat Damage to Upper Drywell Elevations Due to Closed Ventilation Hatches, November 14, 1988.

7. "Dresden Nuclear Power Station Units 2 and 3 Plant Unique Analysis Report," Volumes 1-4, 6 and 7, NUTECH Report No. COM-02-041, May 1983; and Volume 5, Sargent and Lundy, June 1983.

8. "Mark I Containment Program Plant Unique Load Definition," Dresden Station, Units 2 and 3, General Electric Company, NEDO-24566, Revision 2, April 1982.

9. Nutech letter CEC-93-001, A.F. Deardorff to D.S. Skolnik, "Dresden and Quad Cities - Assessment of Effects of Pool Water Levels and Suppression Chamber Volumes on Mark I Program Loads and Structural Evaluations," April 29, 1987.

10. Moody, F.J., "Maximum Flowrate of a Single Component, Two-Phase Mixture," Journal of Heat Transfer, Trans, ASME Series C, Vol. 87, p. 134 (1965).

11. Fauske, H., "The Discharge of Saturated Water Through Tubes," AIChE Preprint 30, Presented at the Seventh National Heat Transfer Conference, Cleveland, Ohio, August 9 through 12, 1964.

12. Robbins, C.H., "Tests of a Full-Scale 1/48 Segment of the Humboldt Bay Pressure Suppression Containment," GEAP-3596, November 17, 1960.

13. NUTECH Letter XCE-51-013 from B.J. Whiteway, P.E. Project Manager, to J.S. Abel, BWR System Design Superintendent, dated November 1989.

14. "Mark I Containment Program, Program Action Plan," General Electric Topical Report EW7610.09, Revision 0, October 29, 1975, through Revision 3, February 15, 1978.

15. "Mark I Containment Program Load Definition Report," General Electric Topical Report NEDO-21888, Revision 0, December 1978, through Revision 2, November 1981.

16. "Mark I Containment Program Structural Acceptance Criteria Plant-Unique Analysis Applications Guide," Task Number 3.1.3, General Electric Topical Report NEDO-24583, Revision 1, July 1979.

17. For a listing of Mark I Program documents, see "Mark I Containment Bibliography and Abstracts for Short-Term Program and Long-Term Program," General Electric Topical Program and Long-Term Program, General Electric Topic Report, NEDE-24728, January 1982.

18. "Mark I Containment Program Quarter-Scale Plant Unique Tests," Task Number 5.5.3, Series 2, General Electric Company, NEDE-21944-P, Volumes 1-4, April 1979.

19. "Containment Data," Dresden 2 and 3, General Electric Company, 22A5743 and 22A5744, respectively, Revision 1, April 1979.

20. "The General Electric Pressure Suppression Containment Analytical Model," General Electric Topical Report NEDO-10320, April 1971; Supplement 1, May 1971; Supplement 2, January 1973.

21. Pacific Nuclear Letter CWE 84-160, "Mark I Torus Attached Piping Evaluation for New Load Case," April 7, 1992.

22. Fitzsimmons, G.W. et al., "Mark I Containment Program Full-Scale Test Program Final Report," Task Number 5.11, General Electric Company, NEDE-24539-P, April 1979; "Mark I Containment Program Letter Report MI-lR-81-01 and MI-LR-81-01-P"; "Supplemental Full-Scale Condensation Test Results and Load Confirmation - Proprietary and Nonproprietary Information," General Electric Company, May 6, 1981; and "Mark I Containment Program - Full-Scale Test Program - Evaluation of Supplemental Tests," General Electric Company, NEDO-24539, Supplement 1, July 1981.

23. Bechtel Power Corporation, "Mark I Containment Program Analysis of Full-Scale Test Facility for Condensation Oscillation Loading, Task 5.17.3," General Electric Proprietary Report NEDE-24645-P, July 1979.

24. "Mark I Containment Program Application Guides," Volumes 1 through 8, NEDE-24555.

25. A. J. Wheeler, "Mark I Containment Program Analytical Model for Computing Transient Pressures and Forces in the Safety-Relief Valve Discharge Line," General Electric Proprietary Report NEDE-23749-P, February 1978.

26. Letter from J. A. Zwolinski (NRC) to D. L. Farrar (CECo), "Mark I Containment Long-Term Program," September 18, 1985.

27. L. D. Steinart, "Long-Term Application of Drywell/Wetwell Differential Pressure Control," General Electric Topical Report NEDM-24527, March 1978.

28. Asia, R.A., et al., "Mark I Containment Program Final Report, Monticello T-Quencher Test," General Electric Proprietary Report NEDE-21864-P, July 1978.

29. B.J. Patterson, "Monticello T-Quencher Thermal Mixing Test Final Report," General Electric Proprietary Report NEDE-24542-P, April 1979.

30. Dresden Nuclear Power Station Unit 3, FSAR Amendment 23, Hydrogen Generation in a Boiling Water Reactor.

31. GE Analytical Model for Loss of Coolant Analysis in Accordance With 10 CFR 50 Appendix K, NEDO-20566, January 1975.

32. Dresden Station Special Report No. 39, Analysis of Hydrogen Generation and Control in Primary Containment Following Postulated LOCA, December 1974 including Supplement 1 through Amendment 2.

33. Generation and Mitigation of Combustible Gas Mixtures in Inerted BWR Mark I Containments, GE NEDO-22155, June 1982.

34. "LPCI Heat Exchanger M12-2-86-32 & 33 Dresden Station", SNED memo M. T. Fredrick to H. E. Bliss, 7/28/87.

35. ASHRAE Guide.

36. Koonty, R.L.; Nelso, C.T.; and Baurmash, L., "Leakage Characteristics of Conventional Building Components for Reactor Housing Construction," Transactions of the American Nuclear Society, Vol. 4, No. 2., p. 365, November 1961.

37. Nutech Report COM-0708-03, Rev. 0, "Evaluation of 18-inch Containment Isolation Valves for Dresden Station, Units 2 & 3, and Quad Cities Station, Units 1 & 2."

38. Nuclear Regulatory Commission, Regulatory Standard Review Plan, Directorate of Licensing, Section 6.2.5, "Combustible Gas Control in Containment," March 1975.

39. Code of Federal Regulations, 10 CFR 50, "Licensing of Production and Utilization Facilities," Appendix A - General Design Criteria.

40. Code of Federal Regulations, 10 CFR 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors, December 28, 1973.

41. General Electric Analytical Model for Loss of Coolant Analysis in Accordance with 10 CFR 50, Appendix K, NEDO-20566, DRAFT.

42. General Electric, "An Analytical Procedure for Conservative Calculation of Core Metal-Water Reaction Following a Design Basis Loss-of-Coolant Accident," NEDO-11013-77, May 1972.

43. Dresden Special Report 39, Supplement 1, Combustible Gas Control System Design Report.

44. Safety Evaluation by the Division of Reactor Licensing, USAEC, In the Matter of Commonwealth Edison Company, Dresden Station, Unit 2, Docket No. 50-237, October 17, 1969.

45. Safety Evaluation by the Division of Reactor Licensing, USAEC, In the Matter of Commonwealth Edison Company, Dresden Station, Unit 3, Docket No. 50-249, November 18, 1970.

46. Regulatory Guide 1.3, "Assumptions used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors," Revision 2, June 1974.

47. BNWL-1244, Removal of Iodine and Particles from Containment Atmospheres by Sprays - CSE Interim Report, R.K. Hilliard, et al., February, 1970.

48. BNWL-754, Nuclear Safety Quarterly Report, July, August, September, and October 1967; June 1968.

49. BNWL-926, Nuclear Safety Quarterly Report - August, September, and October 1968; December 1968.

50. BNWL-1547, Natural Transport Effects in Fission Product Behavior in the Containment Systems Experiment, R.K. Hilliard and L.F. Coleman, December 1970.

51. IN-1325, Simulated Design Basis Accident Tests of the Carolinas Virginia Tube Reactor - Preliminary Results, J.A. Norberg, et al., October 1969.

52. Personal Communication RCS-1-71, R.C. Schmitt (Idaho Nuclear) to G.E. Wade (GE), Anemometer Test Results in CVTR, January 8, 1971.

53. Roberts, A., et al., "Methane Layering in Mine Airways," Colliery Guardian, October 25, 1962, pp. 535-541.

54. Personal Communication, Dr. F.S. Thomas (formerly of the National Research Laboratory) with L.B. Nesbitt (GE), March 17, 1970.

55. Oak Ridge National Laboratory NSIC-5, U.S. Reactor Containment Technology, pp. 10.42, 10.43, 10.110, 10.111, Oak Ridge, Tennessee, August 1965.

56. Duquesne Light Company, Reactor Plant Container Integrity Test, Core 1, Seed 2, DLCS-3570201, USAEC Report TID-5942, 1960.

57. Duquesne Light Company, Reactor Plant Container Integrity Test, Core 1, Seed 2, DLCS-3570101, First Issue, June 29, 1960.

58. Humboldt Bay, Pacific Gas and Electric Company, Report on Pressure Suppression Containment System Leakage Rate Testing at Humboldt Bay Power Plant, Unit No. 3.

59. Deleted.

60. Deleted.

61. Safety Evaluation Tracking No. 1998-04-247.

62. "The GE Pressure Suppression Containment Analytical Model," NEDO-10320, April 1971.

63. "Mark I Containment Program Load Definition Report," NEDO-21888, Rev. 2, November 1981.

64. NUREG-0800, U. S. Nuclear Regulatory Commission, Standard Review Plan, Section 6.2.1.1.C, "Pressure-Suppression Type Containment," Revision 6, August 1984.

65. 'Safety Evaluation Report – Mark I Containment Program," NUREG-0661.

66. "General Electric Model for LOCA Analysis in Accordance with 10 CFR 50 Appendix K," NEDO-20566A, September 1986.

67. Deleted.

68. "Generic Guidelines for General Electric Boiling Water Reactor Power Uprate," NEDC-31897P-A, May 1992.

69. "The General Electric Mark III Pressure Suppression Containment System Analytical Model," NEDO-20533, June 1974.

70. "Use of SHEX Computer Program and ANSI/ANS 5.1-1979 Decay Heat Source Term for Containment Long-Term Pressure and Temperature Analysis," Letter from Ashok Thadani (NRC) to Gary L. Sozzi (GE), July 13, 1999.

71. "Mark I Containment Program Quarter Scale Plant Unique Tests," NEDE-21944-P, April 1979.

72. “Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate” NEDC-32962P, December 2000.

73. NEDO-30832, “Elimination of Limit on Local Suppression Pool Temperature for SRV Discharge with Quenchers,” Class I, December 1984.

74. OPTIMA2-TR027DR-CNTMT LOAD, “Dresden Units 2 &3 Containment Loads Analysis for SVEA-96 Optima2 Fuel” August 2006.

75. OPTIMA2-TR021DR-LOCA, Revision 5, “Dresden 2 & 3 LOCA Analysis for SVEA-96 Optima2 Fuel”, October 2009.

Table 6.2-1

PRINCIPAL DESIGN PARAMETERS OF PRIMARY CONTAINMENT

General	
Metal material	
Unit 2	SA212 GR B to A300
Unit 3	SA516, Grade 70
Design code	ASME Section III, Subsection B
Drywell	
Cylindrical section — diameter	37 ft
Spherical section — diameter	66 ft
Drywell height	111 ft, 11 in.
Free air volume	158,236 ft^3
Wall plate thickness	
Spherical shell	Varies $^{13}/16$ to $1^{1}/16$ in.
Spherical shell to cylindrical neck	$2^{1}/2$ in.
Cylindrical neck	Varies $^{3}/4$ to $1^{1}/2$ in.
Top head	$1^{1}/4$ in. and $1\text{-}^{7}/16$ in.
Vent System	
Vent pipes	
Number	8
Internal diameter	6 ft, 9 in.
Flow area, total	286 ft^2
Vent header internal diameter	4 ft, 10 in.
Downcomer pipes	
Number	96

Table 6.2-1 (Continued)

PRINCIPAL DESIGN PARAMETERS OF PRIMARY CONTAINMENT

Internal diameter	2 ft, 0 in.
Submergence below suppression	
Pool water level	max 4 ft. min 3.67 ft.

Pressure Suppression Chamber

Water volume	116,300 to 119,800 ft^3
Free air volume	112,800 to 116,300 ft^3
Chamber inner diameter	30 ft
Torus major diameter	109 ft

Suppression Chamber to Drywell Vacuum Breakers

Number valves	12
Vent area, total	2715 in^2
Actuation setpoint	0.5 psi for full open

Reactor Building to Suppression Chamber Vacuum Breaker

Number valves	2
Vent area, total	2.02 ft^2 (Unit 2), 1.87 ft^2 (Unit 3)
Actuation setpoint	-0.5 psi for full open

Table 6.2-1 (Continued)

PRINCIPAL DESIGN PARAMETERS OF PRIMARY CONTAINMENT

Design Conditions	
Design internal pressure and temperature (1)	62 psig at 281°F
Design external pressure and temperature (1)	
Drywell	2 psig at 281°F
Suppression chamber	1 psig at 281°F
Normal internal pressure and temperature	
Drywell	1 psig at up to 150°F
Suppression chamber	0 psig
Mark I loadings	Hydrodynamic loads which result from the dynamic effects of drywell air and steam being rapidly forced into the suppression chamber during a postulated LOCA or safety-relief valve operation associated with plant transient conditions. See Section 6.2.1.3.4.

Note 1: The peak drywell (airspace) temperature is 291°F, which is above the drywell shell design temperature of 281°F. However, the drywell airspace temperature peaks briefly as shown in Figure 6.2-33. Because the drywell shell heatup is governed by heat transfer phenomena that require sustained high temperatures in the drywell atmosphere, this brief peak in the drywell airspace temperature results in a drywell shell temperature below 281°F.

Table 6.2-2

MATERIALS USED TO FILL DRYWELL EXPANSION GAP

A. Polyurethane foam – This material is a polyester-base, flexible, polyurethane foam manufactured to exacting controls from refined raw materials to produce a quality foam suitable for use in areas of high radiation. Sheets used conform to the following requirements:

1. Base specification: MIL-PPE-200F
2. Chemistry: Isocyanate foam formed by reaction of polyisocyanates with polyester polyols
3. Density: 2 pcf ±0.10 pcf
4. Thermal value: .26 K factor
5. Service temperature: 285°F maximum
6. Physical properties:
   a. Tensile – 12 psi minimum
   b. Elongation – 100%
   c. Compressibility – 35% at 1.0 psi maximum
   d. Compression set – 10% at 50% compressibility
7. Sheet size: 2 1/4 in. x 2 ft. x 8 ft. with tolerances as specified by MIL-C-26861
8. Heat of combustion: 12,000 Btu/lb
9. Self-ignition temperature: 1000°F
10. Ignition temperature: 500°F to 700°F

B. Adhesive cement for foam sheets – Polyurethane air-drying compound of brushing consistency. Application of the cement was made to the drywell shell over the entire contact area for each foam sheet at the thickness recommended by the manufacturer.

C. Sealing tape for foam sheets – Epoxy-impregnated fiberglass tape of a width not less than 3 inches. This tape was installed over all joints of cover panels as the panels were placed, with the tape centered on the joints and with a lap of not less than 1 inch at all ends of the tape.

D. Fibrous glass, epoxy premolded cover panels – These panels are made of fibrous glass in chopped fiber form with fibers 3/4 to 1 inch in length with an isophtallic polyester resin as a binder. Properties of the mix are as follows:

Table 6.2-2 (continued)

MATERIALS USED TO FILL DRYWELL EXPANSION GAP

1. Flexural strength: 16,500 psi
2. Flexural modulus of elasticity: 5.8×10^5 psi
3. Tensile strength: 8,000 psi
4. Barcol hardness: 50
5. Thickness: 1/4-inch minimum and 3/8-inch maximum; these panels were shop fabricated in sections using field-measured molds for each of the cylinder, knuckle, and spherical portions of the drywell

E. Steel anchor fasteners – These were 4-in. x 4-in. x 1/4-in. steel plates with 1/2-inch diameter steel studs welded to face of plates. Studs were placed at 24-inch centers in both directions and the length of the studs was sufficient to project 1 1/2 inches from the front face of the cover panels.

Table 6.2-3

CONTAINMENT PRESSURE AND PEAK TORUS TEMPERATURE FOR VARIOUS COMBINATIONS OF CONTAINMENT SPRAY AND CORE SPRAY PUMP OPERATION

Summary of Limiting Dresden Containment Analyses Results

CASE**	Short Term (<600 seconds) Containment Pressure Case for NPSH	Long Term (>600 seconds) Containment Pressure Case for NPSH	Long Term Suppression Pool Heatup Case (DBA-LOCA)
Heat Sinks	yes	yes	yes
Suppression Pool Temperature at 600 sec (°F) (At initiation of operator actions).	168	N/A	N/A
Suppression Chamber Airspace Pressure at 600 sec (psig) (At initiation of operator actions).	5.4	N/A	N/A
Peak Long Term Suppression Pool Temperature (°F)	N/A	196	202
Pressure at time of Peak Suppression Pool Temperature (psig).	N/A	7.2	21
Peak Suppression Chamber Airspace Pressure (psig)	N/A	N/A	36.4

** The limiting containment overpressure curve is a combination of the Short Term Case and the Long Term Case. The Short Term Case was used from accident initiation until 600 seconds. The Long Term Case was used from 600 seconds until termination of the accident scenario. A description of the containment analyses case specific assumptions are as follows:

Table 6.2-3 (continued)

Short Term (<600 seconds) Containment Pressure (for NPSH)
With ECCS initiation all LPCI pumps start vessel injection mode and inject directly into the drywell (no flow to vessel) at a flow rate of 5100 gpm per pump during the first 10 minutes of this event. After receiving a signal for CS initiation, the two CS pumps are injecting into the vessel at a flow rate of 6200 gpm per pump for the first 10 minutes of the event.

Long Term (>600 seconds) Containment Pressure (for NPSH)
Above nominal pump flow rate for LPCI and core spray pumps for the first 10 minutes and nominal pump flow rate after 10 minutes. Containment initial conditions to minimize containment pressure, drywell and torus shell heat sinks modeled.

Long Term Suppression Pool Heatup (for DBA-LOCA)
Above nominal pump flow rate for LPCI and core spray pumps for the first 10 minutes and nominal pump flow rate after 10 minutes. Containment initial conditions to maximize containment pressure, drywell and torus shell heat sinks not modeled.

Table 6.2-3a

KEY PARAMETERS FOR CONTAINMENT ANALYSIS

	Short Term (<600 seconds) Containment Pressure Case for NPSH	Long Term (>600 seconds) Containment Pressure Case for NPSH	Long Term Suppression Pool Heatup Case for DBA LOCA
Decay Heat Model	ANS 5.1+2σ	ANS 5.1+2σ	ANS 5.1+2σ
Initial Suppression Pool Temperature (°F)	98	95	98
Feedwater Added	yes	yes	yes
Pump Heat Added	yes	yes	yes
Heat Exchanger K Value (BTU/sec-°F)	N/A	281.7 (see note below)	262
Initial Drywell Pressure (psia)	15.70	15.70	16.2
Initial Suppression Chamber Pressure (psia)	14.70	14.70	14.70
Initial Drywell Temperature	N/A	150	150
Initial Drywell Relative Humidity (%)	N/A	100	100
Initial Suppression Chamber Relative Humidity (%)	N/A	100	100

Note: The CCSW flow rate may need to be throttled to less than 5,000 gpm at times of high suppression pool pressure to maintain the required differential pressure with the LPCI system. A lower CCSW flow rate reduces the K-factor and heat transfer rate. However, analyses confirm that the CCSW flow rate required to maintain the required differential pressure is greater than the CCSW flow rate necessary to ensure that LPCI and CS pump NPSH is not adversely affected and that the existing suppression pool heat-up case for the DBA LOCA remains bounding.

Table 6.2-3b

HEAT EXCHANGER HEAT TRANSFER RATE

Case	Shell Side Flow Rate (LPCI Pump) GPM	Tube Side Flow Rate (CCSW Pump) GPM	K-Value BTU/sec-°F	Heat Transfer Rate (165°F Shell Side Temperature, 95 °F Tube Side Temperature) Million BTU/hr
Long Term Suppression Pool Heatup	5000	5000	281.7	71.0

The heat exchanger parameters identified in this table reflect the new basis for system capability.

Table 6.2-4

MARK I CONTAINMENT PROGRAM INITIATED MODIFICATIONS

Component	Modification Description
Torus	Additional ring girder reinforcement
	Miter joint support saddles and saddle extension plates
	Additional ring-girder-to-torus weld
	Thermowells (for SPTMS)
Vent System	Downcomer/vent header stiffeners
	Downcomer lateral bracing
	Downcomer longitudinal bracing
	Vent header deflector
	Vent line drain reinforcement
	Torus-to-drywell vacuum breakers
	Vacuum breaker header support
Internal Structures	Catwalk midbay supports
	Catwalk lateral bracing
	Catwalk supports at ring girders
	Conduit rerouted
Wetwell Piping Modificatons (Internal)	Spray header supports
	HPCI turbine pot drain support
	HPCI turbine exhaust line support
	ECCS suction strainer reinforcement
	LPCI full-flow test line supports
Relief Valve Discharge Line Piping	Reinforced vent line penetration
	Added T-quenchers
	Added T-quencher supports
	Added RV line support
	SRVDL vacuum breakers

Table 6.2-4 (Continued)

MARK I CONTAINMENT PROGRAM INITIATED MODIFICATIONS

Component	Modification Description
System Modificatons	Torus-to-drywell Delta-P
	SRV logic
	SPTMS
Torus Attached Piping (External)	ECCS suction header penetration and tee reinforcement
	ECCS suction header snubbers
	LPCI penetrations reinforcement
	HPCI turbine exhaust penetration reinforcement
	Small diameter piping modifications
	Large diameter piping modifications
	LPCI full-flow test line tee replacement

Table 6.2-5

ASSUMED PLANT CONDITIONS AT INSTANT OF TRANSIENT LISTED FOR THE PLANT UNIQUE LOAD DEFINITION

	DBA Pipe Break (Operating Delta-P)	DBA Pipe Break (Zero Delta-P)	IBA Pipe Break	SBA Pipe Break
102% Licensed Power (MWt)	2578	2578	2578	2578
Initial Suppression Pool Temperature (°F)	82.5	82.5	95	95
Downcomer Submergence (ft)	4.0	4.0	4.0	4.0
Suppression Pool Airspace Volume (ft^3)				
Drywell	158236	158236	158236	158236
Wetwell	116645	116645	116645	116645
Suppression Pool Airspace Pressure (psig)				
Drywell	1.25	0.75	Bounds both operating and zero Delta-P conditions	Bounds both operating and zero Delta-P conditions
Wetwell	0.15	0.75		

Table 6.2-6

Intentionally Deleted

Table 6.2-7

CONTAINMENT COOLING EQUIPMENT SPECIFICATIONS

Containment Cooling Heat Exchangers

Number	2
dP – river water to containment water	7 psi (1 LPCI pump), 20 psi (2 LPCI pumps)
Primary (shell) design pressure	375 psi
Secondary (tube) design pressure	375 psi

Containment Cooling Heat Exchanger Capability

Basis	LPCI Flow (gal/min)	LPCI Temp. °F Note 1	CCSW Flow (gal/min)	CCSW Temp. °F Note 2	Heat Load (Btu/hr)
Heat exchanger design specification (original)	10,700	165	7000	95	98.6×10^6
Heat exchanger design specification (new)	5000	165	5000	95	71.0×10^6

Heat Exchanger Codes

Shell Side	Carbon Steel A212, Grade B
Code	ASME Section III (1965, Class C) Requirements per manufacturer's specification sheet. Certificate of Shop Inspection indicates construction per applicable code. Berlin Chapman Specification Sheet specifies heat exchanger built to ASME Section III.
Radiography requirements	Tested in accordance with GE Specification 21A5451, Section 4.0 which states testing per ASME Section III, Class C. Manufacturer's data sheet specified joint efficiency of 100% and radiography as complete.

Table 6.2-7 (continued)

CONTAINMENT COOLING EQUIPMENT SPECIFICATIONS

<u>Containment Spray Headers</u>	
Drywell Spray Headers	
Number	2
Size	8 in. schedule 160
No. of nozzles (each)	160
Type nozzle	Fog jet
Suppression Chamber Spray Header	
Number	1
Size	4 in. schedule 40
No. of nozzles	12
Type	Fog jet

Notes:
1. Containment water design temperature.
2. River water design temperature.

Table 6.2-8

REACTOR BUILDING AIR INLEAKAGE

Wind Speed (mph)	Pressure on Windward Side of Building (in.H_2O)[1]	Pressure on Leeward Side of Building (in.H_2O)[1]	Reactor Building Pressure (in.H_2O)[1]	Siding Leakage (ft^3/min)	Door Leakage (ft^3/min)	Piping/Electrica lPenetration Leakage (ft^3/min)	Total Reactor Building Leakage (ft^3/min)
0	0.0	0.0	-0.25	60	325	92	477
5	0.011	-0.006	-0.256	62	340	94	496
10	0.043	-0.024	-0.274	66	365	101	532
15	0.094	-0.052	-0.302	74	410	111	595
20	0.174	-0.096	-0.346	84	470	127	681
25	0.271	-0.150	-0.400	97	535	147	779
30	0.390	-0.217	-0.467	113	605	172	890
50	1.090	-0.600	-0.850	200	905	312	1417
100	4.340	-2.410	-2.660	575	1720	975	3270

Note:
1. Pressures are relative to barometric pressure in an undisturbed atmosphere.

Table 6.2-9

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-101	9207A	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-101	9207B	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-101	9208A	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-101	9208B	Drywell Sample	AO Gate	O	O	GC	Group 2[7]	AC Solenoid[8]	1	5	25 (356)
X-105A	203-1A	Main Steam	AO Globe	I	O	GC	Group 1	AC/DC Solenoid/Air Pilot Spring Closed [8]	20	3-5	12-1 (345-1)
X-105A	203-2A	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-105B	203-1B	Main Steam	AO Globe	I	O	GC	Group 1		20	3-5	12-1 (345-1)
X-105B	203-2B	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-105C	203-1C	Main Steam	AO Globe	I	O	GC	Group 1		20	3-5	12-1 (345-1)
X-105C	203-2C	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-105D	203-1D	Main Steam	AO Globe	I	O	GC	Group 1		20	3-5	12-1 (345-1)
X-105D	203-2D	Main Steam	AO Globe	O	O	GC	Group 1		20	3-5	12-2 (345-2)
X-106	220-1	Main Steam Line Drains	MO Globe EC8274	I	C	SC	Group 1	AC	2	45	12-1 (345-1)
X-106	220-2	Main Steam Line Drains	MO Globe EC8275	O	C	SC	Group 1	DC	2	45	12-2 (345-2)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-107A (B)	220-58A	Feedwater	Check	I	O	N/A	N/A	Self	18	N/A	14 (347)
X-107A (B)	220-62A	Feedwater	Check	O	O	N/A	N/A	Self	18	N/A	14 (347)
X-107B (A)	220-58B	Feedwater	Check	I	O	N/A	N/A	Self	18	N/A	14 (347)
X-107B (A)	220-62B	Feedwater	Check	O	O	N/A	N/A	Self	18	N/A	14 (347)
X-108A	1301-1	Isolation Condenser Steam Supply	MO Gate	I	O	GC	Group 5	AC	14	40	28 (359)
X-108A	1301-2	Isolation Condenser Steam Supply	MO Gate	O	O	GC	Group 5	DC	14	45	28 (359)
X-108A	1301-17	Isolation Condenser Vent	AO Globe	O	O	GC	Group 1	AC Solenoid[8]	3/4	10	28 (359)
X-108A	1301-20	Isolation Condenser Vent	AO Globe	O	O	GC	Group 1	AC Solenoid[8]	3/4	10	28 (359)
X-108B	0299-97B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-108B	0299-98B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-108B	0299-99B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-108B	0299-100B	RVWLIS Backfill	Check	O	O	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-109B(A)	1301-3	Isolation Condenser Condensate Return	MO Gate	O	C	SC	Group 5	DC	12	45	28 (359)
X-109B(A)	1301-4	Isolation Condenser Condensate Return	MO Gate	I	O	GC	Group 5	AC	12	40	28 (359)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-111A	1001-1A	Shutdown Cooling Supply	MO Gate	I	C	SC	Group 3	AC	16	40	32 (363)
X-111A/B	1001-2A	Shutdown Cooling Supply	MO Gate	O	C	SC	Group 3	DC	14	40	32 (363)
X-111B	1001-1B	Shutdown Cooling Supply	MO Gate	I	C	SC	Group 3	AC	16	40	32 (363)
X-111A/B	1001-2B	Shutdown Cooling Supply	MO Gate	O	C	SC	Group 3	DC	14	40	32 (363)
X-111A/B	1001-2C	Shutdown Cooling Supply	MO Gate	O	C	SC	Group 3	DC	14	40	32 (363)
X-113	1201-1	Cleanup System Supply	MO Gate	I	O	GC	Group 3	AC	8	40	30 (361)
X-113	1201-1A	Cleanup System Supply	MO Globe (13)	I	C	SC	Group 3	AC	2	40	30 (361)
X-113	1201-2	Cleanup System Supply	MO Gate	O	O	GC	Group 3	DC	8	40	30 (361)
X-113	1201-3	Cleanup System Supply	MO Gate	O	C	SC	Group 3	DC	8	40	30 (361)
X-115A (128)	2301-4	HPCI Steam Supply	MO Gate	I	O	GC	Group 4	AC	10	50	51(374)
X-115A (128)	2301-5	HPCI Steam Supply	MO Gate	O	O	GC	Group 4	DC	10	63	51(374)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment (3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-116A	1001-5A	Shutdown Cooling Return	MO Gate	O	C	SC	Group 3	AC	14	50	32 (363)
X-116A	1501-22A	LPCI Core Flooding	MO Gate	O	C	N/A	RM	AC	16	N/A	29-1 (360-1)
X-116A	1501-25A	LPCI Core Flooding	AO Check	I	C	N/A	N/A	AC, Self	16	N/A	29-1 (360-1)
X-116B	1001-5B	Shutdown Cooling Return	MO Gate	O	C	SC	Group 3	AC	14	50	32 (363)
X-116B	1501-22B	LPCI Core Flooding	MO Gate	O	C	N/A	RM	AC	16	N/A	29-1 (360-1)
X-116B	1501-25B	LPCI Core Flooding	AO Check	I	C	N/A	N/A	AC, Self	16	N/A	29-1 (360-1)
X-117	2001-105	DW Floor Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid(8)	3	20	39 (369)
X-117	2001-106	DW Floor Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid(8)	3	20	39 (369)
X-118	2001-5	DW Equipment Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid(8)	3	20	39 (369)
X-118	2001-6	DW Equipment Drain Sump Discharge	AO Diaphragm	O	C	SC	Group 2	AC Solenoid(8)	3	20	39 (369)
X-119	4327-500	Demineralized Water Supply	Hand Gate	O	LC	N/A	N/A	Hand	3	N/A	35-1 (366)
X-119	4327-502	Demineralized Water Supply	Hand Globe	I	LC	N/A	N/A	Hand	3	N/A	35-1 (366)
X-119	1916-500	Demineralized Water Supply	Hand Globe	I	LC	N/A	N/A	Hand	2	N/A	31 (362)
X-119	RV-4399-915(15)	Demineralized Water Supply	Relief	I	C	N/A	N/A	Self	1	N/A	35-1 (366)
X-120	4640-500	Service Air Supply	Hand Globe	O	LC	N/A	N/A	Hand	1	N/A	38 (368)
X-120	Various	Service Air Supply	Hand Gate, Plug	I	C	N/A	N/A	Hand	1	N/A	38 (368)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment (3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-121	4722	Instrument Air Supply	AO Globe	O	O	N/A	RM	AC Solenoid	2	N/A	37-2 (367-2)
X-121	4724	Instrument Air Supply	AO Globe	O	O	N/A	RM	AC Solenoid	2	N/A	37-2(367-2)
X-121	4799-530	Instrument Air Supply	Check	O	O	N/A	N/A	Self	2	N/A	37-2 (367-2)
X-121	4799-531	Instrument Air Supply	Check	O	O	N/A	N/A	Self	2	N/A	37-2(367-2)
X-121	4799-1775	Instrument Air Supply	Hand Globe	O	LC	N/A	N/A	Hand	1/2	N/A	37-2(367-2)
X-121	4799-1776	Instrument Air Supply	Hand Globe	O	LC	N/A	N/A	Hand	1/2	N/A	37-2(367-2)
X-122	220-44	Rx Water Sample	AO Globe	I	O	GC	Group 1(7)	AC Solenoid	3/4	5	26-2 (357-2)
X-122	220-45	Rx Water Sample	AO Globe	O	O	GC	Group 1(7)	AC Solenoid	3/4	5	26-2 (357-2)
X-123	3702	RBCCW Supply	MO Gate	O	O	N/A	RM	AC	6	60(14)	20 (353)
X-123	3769-500	RBCCW Supply	Check	I	O	N/A	N/A	Self	6	Standard	20 (353)
X-124	3703	RBCCW Return	MO Gate	O	O	N/A	RM	AC	6	60(14)	20 (353)
X-124	3706	RBCCW Return	MO Gate	I	O	N/A	RM	AC	6	60(14)	20 (353)
X-124	RV-3799-277(15)	RBCCW Return	Relief	I	C	N/A	N/A	Self	1	N/A	(353)
X-125	1601-23	DW Vent	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-125/318A	1601-24	DW and Torus Vent	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-125	1601-62	DW Vent Relief	AO Globe	O	C	SC	Group 2	AC Solenoid	2	15	25 (356)
X-125/318A	1601-63	DW and Torus Vent to SBGT	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	6	10	25 (356)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-126	1601-21	DW Inert and Purge	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-126/304	1601-22	DW and Torus Vent from Rx Building	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-126/304	1601-55	DW and Torus Inerting	AO Butterfly	O	O	GC	Group 2	AC Solenoid(8)	4	15	25 (356)
X-304	1601-56	Torus Inerting and Purge	AO Butterfly	O	O	GC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-126/304	1601-57	DW and Torus N_2 Makeup	MO Globe	O	O	GC	Group 2	AC	1	15	25 (356)
X-304	1601-58	Torus Nitrogen Makeup	AO Globe	O	C	GC	Group 2	AC Solenoid	1	15	25 (356)
X-126	1601-59	DW Nitrogen Makeup	AO Globe	O	O	GC	Group 2	AC Solenoid(8)	1	15	25 (356)
X-130 (138)	1101-15	Standby Liquid Control	Check	I	C	N/A	N/A	Self	1½	N/A	33 (364)
X-130 (138)	1101-16	Standby Liquid Control	Check	O	C	N/A	N/A	Self	1½	N/A	33 (364)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[(1)]	Valve Number	Line Isolated	Valve Type[(2)]	Location Relative to Containment[(3)]	Normal Status[(4)]	Actuation on PCIS Signal[(5)]	PCIS Signal[(6)]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[(9)]	Reference Drawings[(11)]
X-136J (X-136C)	0733A	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136J (X-136C)	0736-1	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136F (X-136B)	0733B	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136F (X-136B)	0736-2	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136E (X-136D)	0733C	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136E (X-136D)	0736-3	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136H (X-136F)	0733D	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136H (X-136F)	0736-4	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136G (X-136E)	0733E	TIP Ball	Ball	O	C	SC	Group 2	AC Solenoid	1/2	5	37-2 (367-2)
X-136G (X-136E)	0736-5	TIP Shear	Explosive	O	O	N/A	N/A	DC	1/2	N/A	37-2 (367-2)
X-136E (X-136F)	4799-514	TIP Nitrogen Purge	Check	O	C	N/A	N/A	Self	1/2	N/A	37-2 (367-2)
X-139B (139C)	399-506	CRD to Reactor Recirculation Loop	Hand Gate	O	LC	N/A	N/A	Hand	1	N/A	34-1 (365-1)
X-139B (139C)	399-587	CRD to Reactor Recirculation Loop	Hand Gate	O	LC	N/A	N/A	Hand	1	N/A	34-1 (365-1)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[(1)]	Valve Number	Line Isolated	Valve Type[(2)]	Location Relative to Containment[(3)]	Normal Status[(4)]	Actuation on PCIS Signal[(5)]	PCIS Signal[(6)]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[(9)]	Reference Drawings[(11)]
X-143 (X-144)	9205A	Drywell Air Sample	AO Globe	O	O	GC	Group 2[(7)]	AC Solenoid[(8)]	1/2	5	25 (356)
X-143 (X-144)	9205B	Drywell Air Sample	AO Globe	O	O	GC	Group 2[(7)]	AC Solenoid[(8)]	1/2	5	25 (356)
X-143 (X-144)	9206A	Drywell Air Sample	AO Globe	O	O	GC	Group 2[(7)]	AC Solenoid[(8)]	1/2	5	25 (356)
X-143 (X-144)	9206B	Drywell Air Sample	AO Globe	O	O	GC	Group 2[(7)]	AC Solenoid[(8)]	1/2	5	25 (356)
X-143 (X-144)	8507-500, 502-521 (8507-501-521)	Drywell Manifold Samples	Hand Globe	O	C	N/A	N/A	Hand	1/2	N/A	178 (421)
X-143 (X-144)	8501-5A	Drywell Air Sample	AO Globe	O	O	GC	Group 2[(7)]	AC Solenoid[(8)]	1/2	5	25 (356)
X-143 (X-144)	8501-5B	Drywell Air Sample	AO Globe	O	O	GC	Group 2[(7)]	AC Solenoid[(8)]	1/2	5	25 (356)
X-143 (X-144)	8599-629, 631-650 (8599-630-650)	Drywell Manifold Samples	Hand Globe	O	C	N/A	N/A	Hand	1/2	N/A	178 (421)
X-145 (150A)	1501-27B	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)
X-145 (150A)	1501-28B	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-147	3-205-24	Reactor Head Cooling	MO Gate	O	C	SC	Group 2	AC	22	60	357-1
X-147	2-205-24	Reactor Head Cooling	MO Gate	O	C	SC	Group 2	AC	22	60	26-1
X-147	205-27	Reactor Head Cooling	Check	I	C	N/A	N/A	Self	22	N/A	26-1 (357-1)
X-149A (B)	1402-25A	Core Spray to Reactor	MO Gate	O	C	N/A	RM	AC	10	N/A	27 (358)
X-149B (A)	1402-25B	Core Spray to Reactor	MO Gate	O	C	N/A	RM	AC	10	N/A	27 (358)
X-149A (B)	1402-24A	Core Spray to Reactor	MO Gate	O	O	N/A	RM	AC	10	N/A	27 (358)
X-149B (A)	1402-24B	Core Spray to Reactor	MO Gate	O	O	N/A	RM	AC	10	N/A	27 (358)
X-150A (145)	1501-27A	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)
X-150A (145)	1501-28A	Containment Spray	MO Gate	O	C	N/A	RM	AC	10	N/A	29-1 (360-1)
X-202V (146)	2499-1A	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-202V (146)	2499-2A	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-202V (146)	2499-28A	Containment H_2/O_2 Monitor Return	Check	O	C	N/A	N/A	Self	1/2	N/A	706-1 (706-2)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-204A (X-115)	8501-3A	DW Air Sample Return	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	1	5	25 (356)
X-204A (X-115)	8501-3B	DW Air Sample Return	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	1	5	25 (356)
X-204B (127)	2499-1B	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-204B (127)	2499-2B	DW H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-204B (127)	2499-28B	Containment H_2/O_2 Monitor Return	Check	O	C	N/A	N/A	Self	1/2	N/A	706-1 (706-2)
X-209	0299-97A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-209	0299-98A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-209	0299-99A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)
X-209	0299-100A	RVWLIS Backfill	Check	O	C	N/A	N/A	Self	3/8	N/A	26-3(357-3)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number[1]	Valve Number	Line Isolated	Valve Type[2]	Location Relative to Containment[3]	Normal Status[4]	Actuation on PCIS Signal[5]	PCIS Signal[6]	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)[9]	Reference Drawings[11]
X-303A-D	1501-5A	LPCI Suction Pump A	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1501-5B	LPCI Suction Pump B	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1501-5C	LPCI Suction Pump C	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1501-5D	LPCI Suction Pump D	MO Gate	O	O	N/A	RM	AC	14	N/A	29-1 (360-1)
X-303A-D	1599-13A (1501-13A)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1599-13B (1501-13B)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1599-13C (1501-13C)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1599-13D (1501-13D)	LPCI Suction Relief	Relief	O	C	N/A	N/A	Self	2	N/A	29-1 (360-1)
X-303A-D	1402-3A	Core Spray Pump Suction	MO Gate	O	O	N/A	RM	AC	16	N/A	27 (358)
X-303A-D	1402-3B	Core Spray Pump Suction	MO Gate	O	O	N/A	RM	AC	16	N/A	27 (358)
X-303A-D	2301-35	HPCI Pump Suction from Torus	MO Gate	O	C	SC	Group 4	DC	16	97	51 (374)
X-303A-D	2301-36	HPCI Pump Suction from Torus	MO Gate	O	C	SC	Group 4	DC	16	97	51 (374)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-303A-D	1599-61	Torus to Condenser Drain	AO Gate	O	C	SC	Group 2	AC Solenoid	3	10	29-1 (360-1)
X-303A-D	1599-62	Torus to Condenser Drain	AO Gate	O	C	SC	Group 2	AC Solenoid	3	10	29-1 (360-1)
X-304	1601-20A	Torus Vacuum Relief	AO Butterfly	O	C	N/A	RM	AC Solenoid(10)	20	5	25 (356)
X-304	1601-20B	Torus Vacuum Relief	AO Butterfly	O	C	N/A	RM	AC Solenoid(10)	20	5	25 (356)
X-304	1601-31A	Torus Vacuum Relief	Check	O	C	N/A	N/A	Self	20	N/A	25 (356)
X-304	1601-31B	Torus Vacuum Relief	Check	O	C	N/A	N/A	Self	20	N/A	25 (356)
X-309A	8501-1A	Torus Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-309A	8501-1B	Torus Air Sample	AO Globe	O	O	GC	Group 2(7)	AC Solenoid(8)	½	5	25 (356)
X-310A	1402-4A	Core Spray Test Return	MO Globe	O	C	N/A	RM	AC	8	N/A	27 (358)
X-310A	1402-38A	Core Spray Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	1½	N/A	27 (358)
X-310A	1501-13A	LPCI Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	3	N/A	29-1 (360-1)
X-310A	1501-20A	LPCI Test	MO Gate	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-310A	1501-38A	LPCI Test	MO Globe	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-310B(A)	2301-14	HPCI Pump Minimum Flow	MO Globe	O	C	N/A	RM	DC	4	N/A	51 (374)
X-310B(A)	2301-40	HPCI Pump Minimum Flow	Check	O	C	N/A	N/A	Self	4	N/A	51 (374)
X-310B(A)	2301-53	HPCI Pump Minimum Flow	Relief	O	C	N/A	N/A	N/A	4	N/A	51 (374)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-310B	1402-4B	Core Spray Test Return	MO Globe	O	C	N/A	RM	AC	8	N/A	27 (358)
X-310B	1402-38B	Core Spray Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	1½	N/A	27 (358)
X-310B	1501-13B	LPCI Pump Minimum Flow	MO Gate	O	O	N/A	RM	AC	3	N/A	29-1 (360-1)
X-310B	1501-20B	LPCI Test	MO Gate	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-310B	1501-38B	LPCI Test	MO Globe	O	C	N/A	RM	AC	14	N/A	29-1 (360-1)
X-311A	1501-18A	LPCI Suppression Pool Spray	MO Globe	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-311A	1501-19A	LPCI Suppression Pool Spray	MO Gate	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-311B	1501-18B	LPCI Suppression Pool Spray	MO Globe	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-311B	1501-19B	LPCI Suppression Pool Spray	MO Gate	O	C	N/A	RM	AC	6	N/A	29-1 (360-1)
X-312	2301-34	HPCI Condensate Drain	Check	O	C	N/A	N/A	Self	2	N/A	51 (374)
X-312	2301-71	HPCI Condensate Drain	Stop Check	O	C(12)	N/A	N/A	Self	2	N/A	51 (374)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

Containment Penetration Number(1)	Valve Number	Line Isolated	Valve Type(2)	Location Relative to Containment(3)	Normal Status(4)	Actuation on PCIS Signal(5)	PCIS Signal(6)	Power Supply	Line Size (in.)	Maximum Isolation Time (sec)(9)	Reference Drawings(11)
X-316A	2499-3A	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-316A	2499-4A	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-316B	2499-3B	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-316B	2499-4B	Torus H_2/O_2 Monitor	Solenoid	O	C	N/A	RM	AC Solenoid	1/2	N/A	706-1 (706-2)
X-317A	2301-45	HPCI Turbine Exhaust	Check	O	C	N/A	N/A	Self	24	N/A	51 (374)
X-317A	2301-74	HPCI Turbine Exhaust	Stop Check	O	C(12)	N/A	N/A	Self	12	N/A	51 (374)
X-318A	1601-60	Torus Vent	AO Butterfly	O	C	SC	Group 2	AC Solenoid(8)	18	10	25 (356)
X-318A	1601-61	Torus Vent Relief	AO Globe	O	C	SC	Group 2	AC Solenoid(8)	2	15	25 (356)

Table 6.2-9 (Continued)

PRINCIPAL PENETRATIONS OF PRIMARY CONTAINMENT AND ASSOCIATED ISOLATION VALVES

NOTES TO TABLE 6.2-9

1. 100- and 200-series penetration numbers are typically drywell penetrations
   300-series penetration numbers are suppression chamber penetrations
   Penetration numbers shown are for Unit 2. Unit 3 penetration numbers, if different, are shown in parentheses.

2. AO — Air-operated
   MO — Motor-operated

3. I — Inside primary containment
   O — Outside primary containment

4. O — Normally open
   C — Normally closed

5. GC — Goes closed
   SC — Stays closed

6. PCIS — Primary Containment Isolation System Group Isolation Designations - refer to Section 7.7 for a definition of the group isolations.
   RM — Remote manual
   N/A — Not applicable

7. Valve can be reopened after isolation for sampling

8. Fails closed on loss of air

9. Standard closing rate for MO Globe valves is 4 in./min. Standard closing rate for MO Gate valves is 12 in./min.

10. Fails open on loss of air

11. Drawing numbers are Unit 2 P&ID numbers. Unit 3 P&ID numbers are shown in parentheses.

12. The valve position indicated relates to the valve disk position.

13. EC8274 & EC8275.

14. This is a clarification, a maximum closure time of 60 seconds is still considered "Standard" per NUREG-0800.

15. This value was installed to address the overpressurization concerns raised by Generic Letter 96-06.

Table 6.2-10
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 2

System	Penetration No.	Valve No.
Main Steam	X-105A, B, C, D	2-220-10A, 10B, 10C, 10D 2-3099-87, 88, 89, 90
Main Steam	X-106	2-220-5
Feedwater	X-107A	2-220-103A 2-3299-52
Feedwater	X-107B	2-220-103B 2-3299-50
Isolation Condenser	X-108A	2-1301-34, 505, 606, 645
RVWLIS Backfill	X-108B	2-0299-108B, 110B, 112B, 113B, 114B, 115B
Isolation Condenser	X-109B	2-1301-32, 601, 604
Shutdown Cooling	X-111A, B	2-1001-200, 90A, 90B, 90C, 91A, 91B, 91C
Shutdown Cooling	X-111A	2-1001-45A, 47A
Shutdown Cooling	X-111B	2-1001-45B, 47B
Cleanup	X-113	2-1201-31 2-1299-11, 004
HPCI	X-115A	2-2301-16
LPCI	X-116A	2-1501-23A ,92A, 2-1599-2A
Shutdown Cooling	X-116A	2-1001-14A
LPCI	X-116B	2-1501-23B, 92B, 2-1599-2B
Shutdown Cooling	X-116B	2-1001-14B
Drywell Floor Drains	X-117	2-2099-871
Drywell Equipment Drains	X-118	2-2099-552
Clean Demin Water	X-119	2-1916-500 2-4327-500, 502
Service Air	X-120	2-4640-500
Instrument Air	X-121	2-4799-100, 101, 532, 533, 1775, 1776
Recirculation Sample	X-122	2-220-42
RBCCW	X-123	2-3799-30,132
RBCCW	X-124	2-3799-29
Primary Containment Vent	X-125	2-1605-500, 2-1699-81

Table 6.2-10

LOCKED CLOSED CONTAINMENT ISOLATION VALVES – UNIT 2
(Continued)

System	Penetration No.	Valve No.
Primary Containment Vent	X-126	2-1699-72 2-8599-526
Standby Liquid Control	X-130	2-1199-107
CRD Hydraulics	X-139B	2-0399-506, 585, 586, 587
Sample System	X-143	2-8507-500, 502 through 521 2-8599-629, 631 through 650
Containment Spray	X-145	2-1501-30B 2-1599-124B, 125B
Reactor Head Spray	X-147	2-205-25 2-0299-57
Core Spray	X-149A	2-1402-32A, 33A, 5A 2-1403-A-500 2-1404-A-500
Core Spray	X-149B	2-1402-32B, 33B, 5B 2-1403-B-500 2-1404-B-500
Containment Spray	X-150A	2-1501-30A 2-1599-124A, 125A
CAM	X-202V	2-2499-7A, 31A, 32A
Sample System	X-204A	2-8599-617
CAM	X-204B	2-2499-7B, 31B, 32B
RVWLIS Backfill	X-209	2-0299-108A, 110A, 112A, 113A, 114A, 115A
HPCI	X-303A, B, C, D	2-2301-37, 93, 94 2-2399-15,
Core Spray	X-303A, B, C, D	2-1402-10A, 10B 2-1499-37A, 37B
LPCI	X-303A, B, C, D	2-1501-57A, 57B, 70A, 70B, 72A, 72B, 73A, 73B 2-1599-27A, 27B, 75A, 75B, 68

Table 6.2-10
LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 2
(Continued)

System	Penetration No.	Valve No.
Pressure Suppression	X-304	2-1699- 500A, 500B, 63B 2-1623-DV
Pressure Suppression	X-305A	2-1699-99
Pressure Suppression	X-305B	2-1699-100
Pressure Suppression	X-305D	2-1699-75, 77, 65, 66
LPCI	X-310A	2-1501-87A, 2-1599-31A
LPCI	X-310B	2-1501-87B, 2-1599-31B
LPCI	X-311A	2-1501-40A, 2-1599-126A, 127A
LPCI	X-311B	2-1501-40B, 2-1599-126B, 127B
HPCI	X-312	2-2301-41B
Pressure Suppression	X-313A	2-1699-58A, 61A, 83, 103
Pressure Suppression	X-313B	2-1699-58B, 61B
CAM	X-316A	2-2499-9A
Pressure Suppression	X-316A	2-1699-63A
CAM	X-316B	2-2499-9B
HPCI	X-317A	2-2301-41A, 2-2306-500
Pressure Suppression	X-318A	2-1699-002A

Table 6.2-11

LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 3

System	Penetration No.	Valve No.
Main Steam	X-105A, B, C, D	3-220-10A, 10B, 10C, 10D 3-3099-91, 92, 93, 94
Main Steam	X-106	3-220-5
Feedwater	X-107A	3-220-103B 3-3299-53
Feedwater	X-107B	3-220-103A 3-3299-55
Isolation Condenser	X-108A	3-1301-34, 602 3-1302-500
RVWLIS Backfill	X-108B	3-0299-108B, 110B, 112B, 113B, 114B, 115B
Isolation Condenser	X-109A	3-1301-32, 3-1301-601, 3-1304-500
Shutdown Cooling	X-111A, B	3-1001-90A, 90B, 90C, 91A, 91B, 91C, 4
Shutdown Cooling	X-111A	3-1001-45A, 47A
Shutdown Cooling	X-111B	3-1001- 45B, 47B
Cleanup	X-113	3-1201-32 3-1299-7
Sample System	X-115	3-8599-617
LPCI	X-116A	3-1501-23A, 92A
Shutdown Cooling	X-116A	3-1001-14A
LPCI	X-116B	3-1501-23B, 92B
Shutdown Cooling	X-116B	3-1001-14B
Drywell Floor Drains	X-117	3-2099-871
Drywell Equipment Drains	X-118	3-2099-552
Clean Demin Water	X-119	3-4327-500, 502, 3-1916-500
Service Air	X-120	3-4640-500
Instrument Air	X-121	3-4799-532, 533, 1775, 1776
Recirculation Sample	X-122	3-220-42
RBCCW	X-123	3-3799-137, 139
RBCCW	X 124	3-3799-181

Table 6.2-11

LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 3
(Continued)

System	Penetration No.	Valve No.
Primary Containment Vent	X-125	3-1605-500, 3-1699-81
Primary Containment Vent	X-126	3-1604-500 3-1699-72 3-8502-500 3-8599-527
CAM	X-127	3-2499-7B, 31B, 32B
HPCI	X-128	3-2301-16
Standby Liquid Control	X-138	3-1199-003
CAM	X-139B	3-2499-31A, 32A
CRD Hydraulics	X-139C	3-0399-585, 506, 586, 587
Sample System	X-144	3-8507-501 through 521 3-8599-630 through 650
Containment Spray	X-145	3-1501-30A, 3-1599-124A, 125A
CAM	X-146	3-2499-7A
Reactor Head Spray	X-147	3-205-25
Core Spray	X-149A	3-1402-32B, 33B, 5B, 508, 510
Core Spray	X-149B	3-1402-32A, 33A 5A, 504, 507
Containment Spray	X-150A	3-1501-30B, 3-1599-124B, 125B
RVWLIS Backfill	X-209	3-0299-108A, 110A, 112A, 113A, 114A, 115A
HPCI	X-303A, B, C, D	3-2301-37, 93, 94 3-2399-15
Core Spray	X-303A, B, C, D	3-1402-10A, 10B 3-1499-38, 39 3-1418B-500
LPCI	X-303A, B, C, D	3-1501-70A, 70B, 72A, 72B, 73A, 73B 3-1599-76, 77, 68

Table 6.2-11

LOCKED CLOSED CONTAINMENT ISOLATION VALVES - UNIT 3
(Continued)

System	Penetration No.	Valve No.
Pressure Suppression	X-304	3-1601-A-500 3-1601-B-500 3-1699-61A, 3-1623-DV
Pressure Suppression	X-305A	3-1699-99
Pressure Suppression	X-305B	3-1699-100
Pressure Suppression	X-305D	3-1699-75, 77 3-2351A-DV, 3-2351B-DV
LPCI	X-310A	3-1501-87A
LPCI	X-310B	3-1501-87B
LPCI	X-311A	3-1501-40A, 3-1599-126A, 127A
LPCI	X-311B	3-1501-40B, 3-1599-126B, 127B
HPCI	X-312	3-2301-41B
Pressure Suppression	X-313A	3-1699-59A, 71A, 83
Pressure Suppression	X-313B	3-1699-59B, 71B
CAM	X-316A	3-2499-9A
CAM	X-316B	3-2499-9B
HPCI	X-317A	3-2301-41A
Pressure Suppression	X-316B	3-1699-61B
Pressure Suppression	X-318A	3-1679-52

Table 6.2-12

INCREMENTAL 30-DAY LOW POPULATION ZONE DOSES
FROM ACAD OPERATION

	Thyroid (rem)	Whole Body (rem)
Utilizing Actual Site Meteorology:		
Five percent probable dose due to ACAD operation	5.94	0.037
NRC-calculated dose due to LOCA	90	2
Utilizing Regulatory 1.3 Meteorology:		
Dose due to ACAD operation (4 - 30 days)	22.6	0.070
NRC-calculated does due to LOCA	90	2

HISTORICAL
This table contains Historical Information Only

6.3 EMERGENCY CORE COOLING SYSTEM

This section describes the design bases, system design, performance evaluation, testing, and inspection requirements for the emergency core cooling system (ECCS). The related subject of containment cooling is addressed in Section 6.2.2.

All LOCA PCT evaluations performed are reported to the NRC per 10 CFR 50.46. The UFSAR is marked up for updates within 30 days of the submittal. The 10 CFR 50.46 letter is on file at the site. Between UFSAR updates the latest PCT is tracked by Nuclear Fuel Management or the cognizant equivalent.

The changes due to the GE LOCA analysis in Reference 70 at a licensed power level of 2957 MWt bounds operation at a licensed power level of 2527 MWt. Thus, the GELOCA analysis will remain valid and applicable to operation with GE14 fuel at 2527 MWt or at 2957 MWt as allowed by the Technical Specifications for Extended Power Uprate.

For operation up to 2957 MWt power with SVEA-96 Optima2 fuel, the LOCA analysis used the Westinghouse 10CFR50, Appendix K BWR LOCA methodology with bounding input parameters from the Dresden units. The Dresden analysis inputs are identical for Dresden Units 2 and 3 with the exception of the LPCS delivered flows and shroud leakages. The Westinghouse analysis is applicable to operation with SVEA-96 Optima2 fuel.

6.3.1 Introduction and System Design Bases

The ECCS is designed to provide adequate core cooling across the entire spectrum of line break accidents. It consists of the core spray (CS) subsystem, the low pressure injection (LPCI) subsystem, the high pressure coolant injection(HPCI) subsystem, and the automatic depressurization (ADS) subsystem. The individual subsystems are described in Sections 6.3.2.1 through 6.3.2.4, and the integrated performance is evaluated in Section 6.3.3.2.

The primary principle of coolant system design is to provide core cooling continuity over the entire range of operating and postulated accident conditions. When normal auxiliary power is available, core cooling is achieved by removing heat using the steam turbine-condenser cycle or using the shutdown cooling system.

In the absence of any loss of coolant from the primary system, the core is cooled by relief valve action followed by use of the isolation condenser system under the following conditions:

A. When the reactor is isolated from the main condenser and the shutdown cooling system, or

B. When electrical power is unavailable to the pumps which provide cooling water to the main condenser and shutdown cooling heat exchangers.

However, other means are needed to provide continuity of core cooling during those postulated accident conditions where it is assumed that mechanical failures occur in the primary system and coolant is partially or completely lost from the reactor vessel, and either normal auxiliary power is unavailable to drive the feedwater pumps or the loss of coolant occurs at a rate beyond the capability of the feedwater system. Under these circumstances, core cooling is accomplished by means of the ECCS. Each of these subsystems is designed to cover a specific range of accident conditions and collectively provide a redundancy in kind to avoid undetected common failure mechanisms. Figure 6.3-1 shows the typical range of effectiveness and redundancy for the various subsystems as they were originally designed (see Section 6.3.3.3.1 for more detail). The overall ECCS design bases are as follows:

A. The ECCS is designed to provide adequate core cooling for any mechanical failure of the primary system up to and including a break area equivalent to the largest primary system pipe;

B. The entire spectrum of line breaks, up to and including this maximum, is designed to be protected by at least two automatically actuated, independent cooling methods; and

C. No reliance is assumed to be placed on external sources of power.

Refer to Section 7.3 for a definition of auto-initiation of appropriate action per IEEE 279-1968. For a discussion of integrated ECCS performance analyzed to current regulatory requirements, refer to Section 6.3.3.2.

The design bases of the subsystems which comprise the overall ECCS are provided in the following sections.

6.3.1.1 Core Spray Subsystems

The following design bases have been adopted for each of the two core spray subsystems and aid in evaluating the adequacy of the subsystems:

A. Each core spray subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion.

B. The two independent core spray subsystems shall meet the above design basis requirements without reliance on external power supplies to either core spray subsystem or the reactor system.

C. Each core spray subsystem is designed so that each component of the subsystem can be tested periodically.

6.3.1.2 Low Pressure Coolant Injection Subsystem

The design bases of the LPCI subsystem are as follows:

A. The LPCI subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion.

B. The LPCI subsystem is provided with redundancy in critical components to meet reliability requirements.

C. The LPCI subsystem operates without reliance upon external sources of power.

D. The LPCI subsystem is designed so that each component can be tested and inspected periodically to demonstrate availability of the subsystem.

In addition to its ECCS design bases, the LPCI subsystem also provides the capability to achieve cold shutdown - during the Systematic Evaluation Program (SEP) review of SEP topic VII-3, the NRC determined that General Design Criteria 19 and 34 require the capability of achieving cold shutdown from normal operating conditions using safety grade systems. The containment cooling service water (CCSW) system and pressure relief system are used in conjunction with the LPCI subsystem to provide this capability.

6.3.1.3 High Pressure Coolant Injection Subsystem

The following design basis was adopted for the HPCI subsystem and served as the basis for evaluating the adequacy of the system:

A. The HPCI subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion.

B. The HPCI subsystem shall meet the above design basis requirement without reliance on an external power source. Thus, condenser hotwell inventory is considered unavailable.

C. The HPCI subsystem is designed so that each component of the subsystem can be periodically tested.

6.3.1.4 Automatic Depressurization Subsystem

The ADS subsystem is provided to ensure adequate core cooling when operated with other available ECCS systems determined from the Appendix K single failure criterion. Applicable design bases are the same as for the HPCI subsystem (refer to Section 6.3.1.3). The ADS is provided with power from two separate divisional dc power supplies.

6.3.2 System Design

The following sections discuss the design of the ECCS subsystems.

6.3.2.1 Core Spray Subsystem

6.3.2.1.1 Core Spray Subsystem Interface with Other Emergency Core Cooling Subsystems (Historical)

Under current regulatory requirements, the function of the core spray subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Tables 6.3-21b and 6.3-21c list the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the CS subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

Each core spray subsystem is designed to operate in conjunction with the LPCI subsystem and either the ADS or HPCI subsystems to provide adequate core cooling over the entire spectrum of liquid or steam pipe break sizes. Thus, the ADS size and core spray subsystem head and flow requirements are related.

For small breaks without either feedwater or HPCI availability, the core would uncover while reactor pressure remains above the core spray pump shutoff head. Hence, ADS is actuated to reduce reactor pressure to permit core spray and LPCI to reach rated flow in time to ensure adequate core cooling. Two core spray subsystems or one core spray subsystem and two LPCI pumps, with the assistance of the ADS, provide adequate cooling for all break sizes.

If feedwater or HPCI is available, the necessary depressurization occurs through the addition of cold feedwater to the vessel. Hence, in combination with feedwater or HPCI, two core spray subsystems or one core spray subsystem and two LPCI pumps provide adequate core cooling for all break sizes.

The core spray flow requirement for the GE14 and SVEA-96 Optima2 design basis LOCA analyses is given in Tables 6.3-20b and 6.3-20c, respectively. The following paragraphs contain information on how the core spray flow requirement was determined in the original design. This information is historical and is not needed to support the current design basis.

The core spray flow requirement was established by heat transfer and flow distribution tests on simulated prototype fuel assemblies. These tests are described in detail in References 1 and 2. The original head requirements of the core spray subsystem were determined by a series of analyses of the core spray subsystem in conjunction with either the ADS or HPCI subsystem over the small break size spectrum, since small breaks depressurize the reactor at the slowest rates and, therefore, require the largest core spray head. The size of the ADS or HPCI subsystem plays an important role here also, particularly for the small breaks for which core spray subsystem requires depressurization assistance. As ADS or HPCI capacity is increased, core spray head requirements decrease since the larger the capacity, the faster the vessel will depressurize.

The original determination of the flowrate was based on refined prototype testing of a full scale fuel assembly under actual power and spray distribution conditions. To ensure that the test situations resulted in a limiting case, the test fuel rods were allowed to overheat (1600°F) prior to core spray activation, and the channel boxes were allowed to stay at high temperature. The core spray subsystems were sized to provide the minimum required flowrate to each assembly in the core. Flow distribution in the upper plenum and leakage flow available to fuel rods were also taken into account in establishing the core spray flow requirements.

6.3.2.1.2 Subsystem Characteristics

Each of the two independent core spray loops consists of a pump, valves, piping, and an independent circular sparger ring inside the core shroud just above the core. The normal water source for the pump suction is the suppression pool. Condensate storage tank water is used for initial flushing and for system testing when using suppression pool water is either undesirable or not feasible. The core spray subsystem is shown in Drawings M-27 and M-358. Core spray subsystem equipment specifications are tabulated in Table 6.3-3.

The core spray subsystem pumps are started by initiation signals which are described in Sections 6.3.2.1.4 and 7.3.1.1. The injection valves will open when the reactor pressure decreases below the pressure permissive to open. Core spray flow is sprayed over the top of the core. Water sprayed into the fuel assemblies runs down the channel walls providing a heat sink for the heat radiated from the fuel rods.

The discharge piping of the core spray subsystem is required to be filled and vented for the subsystem to be considered operable. The vent pathways for core spray are through vent valves and a sightglass or open-ended pipe to the reactor building floor drains. A fill system is used to ensure that the core spray discharge lines remain pressurized. This fill system consists of a pump which takes suction from the suppression pool via a core spray pump suction line and discharges to the core spray and LPCI pump discharge lines. A control room alarm is provided to indicate faulty fill system performance.

The core spray pumps and motors are located in the corners at the lowest level of the reactor building. See Tables in UFSAR Section 3.11 for environmental parameters at the core spray pumps and motors locations. Physical separation of the pumps is achieved by locating pumps in different corners of the reactor building as shown by Figure 6.3-3. Each of the two pump rooms contains a room cooler and associated fan as described in Section 9.2.2.

Each core spray pump takes suction from a common ring header that has four suction lines with stainless steel screens located in the torus. These screens are positioned above the bottom of the suppression pool but well below the pool surface to minimize any risk of plugging from debris. Sufficient flow area is available to meet the flow requirements of the combined use of the core spray, LPCI, and HPCI subsystems with four partially plugged suction screens. The screen size (1/8-inch openings) was selected to screen out particles capable of plugging spray nozzles. Additional details of ECCS flow through the strainers are provided in Section 6.2.2.

The core spray pump motors are cooled with core spray pump discharge water. The water flows through a 1-inch line in the pump motor casing and returns to the suction side of the pump. The pump motor cooling system uses no external power source. The pump motors are ac-driven. When normal power is not available, one of the two pumps will receive power from the unit diesel generator and the other from the 2/3 diesel generator. These diesels will automatically start upon loss of normal ac power.

The piping of each core spray subsystem is fabricated of carbon steel from the suppression chamber to the outer isolation valve. Relief valves are utilized for overpressure protection for this section of the piping. On Unit 2 from the outer isolation valves into the reactor, the subsystem is fabricated of carbon steel piping and cast stainless steel valve bodies and designed for service at 1150 psig and 575° F. On Unit 3 from the outer isolation valves into the reactor, the subsystem is fabricated of stainless steel and designed for service at 1250 psig and 575°F. The spray spargers and spray nozzles are fabricated from Type 304 stainless steel to meet the requirements of ASME Section III. The core structure supporting the spray spargers is also fabricated of Type 304 stainless steel material. The vessel nozzle entry material is Ni-Cr-Mo forging fabricated to ASME SA 336 and modified by ASME Code Case 1332.

See Tables in UFSAR Section 3.11 for environmental parameters at the core spray isolation valve locations.

The power sources for the core spray subsystems are located on separate emergency buses that have provisions to protect them from adverse environments such as could be caused by fire or steam line breaks. Power for these emergency buses can be supplied from the diesel generators if offsite power is not available.

A test line capable of full system flow is connected from a point near the outside isolation valve back to the suppression chamber. Flow can be diverted into this line to test operability of the pumps and control system during reactor operation.

Each core spray pump is equipped with a four-position control switch provided with START, AUTO, STOP and PULL-TO-LOCK positions. The control switch has a spring return to AUTO position from both the START and STOP positions. The PULL-TO-LOCK position permits the pump to be stopped by pulling the switch and placing it in the PULL-TO-LOCK position. This four-position control switch arrangement permits the operator to override the automatic start signal, which is necessary during long-term cooling of the reactor core following an accident. In such a case, the operator would secure one core spray pump after assuring that adequate core cooling capability exists by the remaining ECCS components.

Administrative procedures restrict the operation of these control switches. Since each pump has its own control switch, no single failure could preclude operation of both core spray loops.

6.3.2.1.3 Equipment Characteristics

6.3.2.1.3.1 Core Spray Pumps

The design flow capacity of each core spray pump is approximately 4500 gal/min at a total developed pump head of 640 ft, as shown in Figure 6.3-4. The core spray pump motors are rated at 800 hp each with a service factor of 1.15. A service factor (or use factor) is used to define the operating limits beyond which deleterious effects to the motor can be expected. Thus, if a pump is rated at 800 hp with a service factor of 1.15, then deleterious effects to the motor can be expected if the motor is operated beyond 920 hp. Table 6.3-3 indicates the nameplate rating of the pump motors.

6.3.2.1.3.2 Piping

Core spray piping internal to the reactor which connects each spray sparger to its reactor pressure vessel penetration is designed and routed to meet the necessary flexibility requirements for thermal expansion and also to accommodate postulated vessel movement even though such movement is not considered credible.

The core spray nozzle arrangement consists of sixty-five 1HH12 full jet nozzles and sixty-five 1-inch open elbows. The spray outlets are equally spaced with the full jets and open elbows alternating around the sparger. The core spray sparger ring is actually two 180° sections with flow entering each section 15° from the midpoint. Uniform distribution of flow around the sparger was obtained by the use of orifices placed in the entrance of the spray branches around the sparger. The effect of inclination angle is shown in Figure 6.3-5 for the open elbows of the lower header. Variation of the full jet inclination angle has even less effect and is not shown. The effect of azimuth setting is shown in Figure 6.3-6. The design value for azimuth for all nozzles is 0°. As a result of these sensitivity tests, an allowable tolerance of ±1° has been set for all angle settings.

During D3R14 and D2R15, IGSCC flaws were identified at two downcomers elbows and three collars (shroud thermal sleeves) welds. These flaws were evaluated (S&L Report SL-5130 and SL-5197) and it was determined that the design basis for Core Spray would not be affected for up to forty-eight months of hot operation. The impact of projected increasing leakage at the elbow welds on the fuel manufacturer's LOCA-ECCS Analysis of peak cladding temperature must be evaluated at the beginning of each fuel cycle. Other core spray line leakages are considered in LOCA-ECCS analysis (see Section 6.3.3.3.2). During D3R18 and D2R21, the lower portion of all four Core Spray downcomers on both Unit 3 and Unit 2 was replaced with bolted connections to eliminate IGSCC flaws. The impact of the calculated leakage for the bolted Core Spray piping is bounded by the current LOCA-ECCS analysis.

Concern over possible oxygen accumulation in the core spray piping and nozzles was addressed by making an opening at the top of the core spray line divider end plate. The opening is sized to provide a flow in the line of approximately 8 gal/min per loop.

Design of the piping system external to the reactor vessel reflects considerations for potential damage to the piping. The piping runs of each subsystem are physically separated and located to take maximum advantage of protection afforded by structural beams and columns. A sketch of pipe protection provisions is shown on Figure 6.3-3. Drywell penetrations for the core spray pipes are located to achieve minimum length pipe runs within the drywell and to provide maximum circumferential distance between main steam and feedwater lines.

6.3.2.1.3.3 Instrumentation

To provide detection of a core spray line guillotine break in the annulus region between the vessel wall and the core shroud during normal reactor power operation, a differential pressure switch in each of the core spray loops was included in the design. Calibrated to read zero at cold shutdown (reactor and instrument legs cold), this instrumentation provides guillotine break detection while reactor power is greater than, or equal to, 80% and core flow is greater than, or equal to, 90%.

Other local instrumentation provided for monitoring core spray subsystem operation include core spray pump suction pressure, core spray pump discharge pressure, and core spray loop flow (% rated flow).

6.3.2.1.4 Core Spray Operating Sequence

Initiation of each core spray subsystem occurs on any of the following signals:

A. High drywell pressure;

B. Low-low reactor water level coincident with low reactor pressure;

C. Low-low reactor water level coincident with timeout of the ADS high drywell pressure bypass timer.

The core spray system can also be started manually. Refer to Section 7.3 for a complete description of the core spray logic.

During a core spray subsystem test, the test bypass valve is opened to the suppression pool and the pump is started using the remote switch in the control room. The only difference between test and normal standby operation of the core spray subsystem is the use of the pump switch and the test valve.

Upon receipt of a LOCA initiation signal, the test bypass valve is automatically closed. The signal to close the test bypass valve is initiated by the same instrumentation used to activate the core spray system, as shown in Figure 7.3-1. The core spray pump in the test loop remains running unless there is a loss of voltage, in which case the pump will be tripped by undervoltage protective devices. The pump is restarted upon the restoration of power. Other valves in the core spray subsystem will operate as designed on a LOCA initiation signal.

6.3.2.1.4.1 Operating Sequence with Plant on Normal Auxiliary AC Power

Upon receipt of an initiation signal, the core spray pump in each subsystem starts automatically without delay. The injection valves, which admit core spray flow to the reactor vessel, remain closed until the reactor pressure decays below the discharge valve opening interlock pressure. At that time, the valves in each subsystem open to admit flow into the reactor vessel. During the period when the injection valves are closed, pumps are operated on minimum flow bypass to the suppression pool.

The pump suction valves are automatically opened (if closed) and the test bypass valves are automatically closed (if open) immediately upon receipt of an initiation signal. The suction valves are normally open and the test bypass valves are normally closed during normal power plant operation. The suction valve control logic permits the control room operator to override the automatic opening feature and close the valve if required to isolate a system leak.

The estimated core spray subsystem response time for a DBA LOCA in GE analysis is as follows:

A. Less than 3.1 seconds for reaching reactor low-low water level. The analysis assumes high drywell pressure occurs at time zero and that it will take 1 second to process the signal to start ECCS.

B. Five seconds for the pump to accelerate to full speed;

C. Less than 23.3 seconds for the reactor pressure decay below the permissive pressure for the injection valve to start open.

D. Thirty seconds for injection valves to reach full opening after opening signal is received.

The Westinghouse LOCA analysis uses bounding input parameters from the Dresden units. The Dresden analysis inputs are identical for Dresden Units 2 and 3 with the exception of the LPCS delivered flows and shroud leakages. The estimated core spray subsystem response time for a DBA LOCA in Westinghouse analysis differs in high drywell pressure time: the Westinghouse analysis assumes high drywell pressure occurs at time 0.2 seconds. Low-low water level and reactor pressure permissive are calculated. The Westinghouse LOCA analysis is described in Reference 78.

6.3.2.1.4.2 Operating Sequence with Diesel Generator

Upon receipt of an initiation signal coincident with a loss of normal ac power, the following sequence occurs:

A. Diesel generators start (see Tables 6.3-4b, 6.3-4c, and Section 8.3.1.5.3 for the ECCS loading sequence)

B. Permissive available to activate pumps and valves of both subsystems;

C. Pump suction valves open (if closed) in both subsystems;

D. Test bypass valves close (if open) in both subsystems;

E. Completion of a time delay (the allowable value for this time delay is specified in the Technical Specifications), both core spray subsystem pumps receive start permissives.

Separate timers are used to start each core spray subsystem to improve system reliability.

The injection valves in both core spray loops will remain closed until the reactor pressure decays to the permissive pressure, at which time the valves will open to admit flow into the reactor vessel. The pumps are operated on minimum flow bypass which discharges back to the suppression pool during the period they are running with the injection valves closed.

6.3.2.2 Low Pressure Coolant Injection Subsystem

The LPCI subsystem includes the equipment for coolant injection and containment cooling. Refer to Section 6.2.2 for a description of the containment cooling subsystem. Refer also to Section 9.2.1 for a description of the containment cooling service water pumps. The LPCI subsystem is further subdivided into two functional loops. The LPCI subsystem equipment includes two heat exchangers, four containment cooling service water pumps, four LPCI pumps, two drywell spray headers, and a suppression chamber spray header. The LPCI subsystem is shown in Drawings M-29, Sheet 1 and M-360, Sheet 1).

6.3.2.2.1 Low Pressure Coolant Injection Subsystem Interface with Other ECCS Subsystems (Historical)

Under current regulatory requirements, the function of the LPCI subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Tables 6.3-21b and 6.3-21c list the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the LPCI subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

The LPCI subsystem operates in conjunction with the HPCI and core spray subsystems to achieve its core cooling function. During a loss-of-coolant accident, coolant is lost from the core with a corresponding decrease in reactor vessel pressure. The HPCI subsystem operates initially during the high-pressure phase of the accident to supply a small amount of coolant at high pressure.

As the pressure in the reactor vessel decreases, the HPCI subsystem flow ceases and the core spray and LPCI subsystems automatically begin operation to take over the core cooling function. When the pressure in the reactor vessel equals the pressure in the suppression chamber, the LPCI subsystem is capable of delivering maximum capacity. LPCI delivers rated flow with reactor pressure equal to 20 psid (differential pressure between the reactor vessel dome and the drywell). After the core has been flooded to two-thirds height, only one LPCI pump is required to maintain this level.

6.3.2.2.2 Subsystem Characteristics

The LPCI subsystem is required to inject sufficient makeup water to reflood the vessel to the appropriate core height to provide adequate core cooling and is later required to maintain the level at two-thirds core height. The DBA LOCA analyses take credit for operable LPCI pumps as indicated in Table 6.3-21b for GE14 fuel and Table 6.3-21c for SVEA-96 Optima2 fuel, respectively. These analyses also require operation of at least one core spray subsystem to ensure adequate core cooling. To assure long-term cooling of the fuel, the minimum requirements of 4500 gpm of core spray flow to the top of the core and two-thirds core height water level or full height water level coverage to the top of active fuel should be satisfied. The pump head characteristic was selected such that sufficient but less than rated flow is provided before the HPCI turbine is tripped by low vessel pressure. This approach provides core cooling over the complete spectrum of breaks up to the design basis break. The specifications for these pumps are shown in Table 6.3-5 and the performance curve for the LPCI subsystem is shown in Figure 6.3-8.

The two LPCI pumps for each LPCI subsystem are located on the basement floor in shielded rooms in each of two corners of the reactor building. Each LPCI pump room has the necessary piping and instrumentation to perform in any LPCI or containment cooling mode of operation (refer to Section 6.2.2 for a description of containment cooling functions by the LPCI subsystem). A crosstie header between the otherwise separate subsystems makes it possible for the LPCI pumps in one room to deliver their flow through the second loop's piping. This crosstie is located in a well-protected basement floor area and has two normally keylocked open, motor-operated valves. The valves may be closed from the control room if loop isolation is necessary. Separation of the piping provides protection against missiles in the vicinity of the reactor in that only one of the two flow paths must be assumed to be incapacitated by missiles. Missile protection shielding is provided by routing piping along the reactor building structure walls as much as possible.

Each of the two LPCI pump rooms contains its own room cooler and associated fan. Cooling water is normally provided by the service water system, with the containment cooling service water system as a backup, as described in Section 9.2.

The LPCI room cooler fan motors are seismically supported from rod hangers in a pendulum fashion from the ceiling of the reactor building at elevation 517'-6".

The LPCI subsystem is protected from plugging (due to the presence of foreign material which may find its way into the suppression chamber) by the use of multiple suction header connections with strainers. An evaluation of the strainers is provided in Section 6.2.2.

The LPCI pump motors are cooled by use of the LPCI pump discharge water which is routed through a 1-inch line to the pump motor oil coolers and returned to the suction side of the pump. The pump discharge water cools the oil that in turn lubricates and cools the motor. Hence, no external power source is required other than that used to power the pump motors.

During post-accident operation one or more of the LPCI pumps may be used for containment spray mode. The containment long-term response analysis for a DBA LOCA assumes that a minimum of 5000 gal/min is provided by LPCI to cool the containment (refer to Section 6.2.1.3.2.2). Additionally, to meet two-thirds core coverage requirements, continued post-LOCA ECCS flow is required to make up shroud leakage as described by Section 6.3.2.2.3.1. Therefore, post-DBA LOCA operation of the ECCS system must address both core coverage and containment spray requirements. The long term post-LOCA analysis employed the containment spray mode in order to yield the lowest containment pressure over the long term. Note that containment spray mode is not the preferred method of long term cooling, but was assumed in the analysis since it yields the lowest containment pressures and is therefore conservative in determining ECCS pump NPSH requirements.

After a period not exceeding 2 hours, the operator can manually stop one LPCI pump and start the two containment cooling service water pumps powered by the same diesel generator (assuming offsite power is not available). Operating procedures have the operator start the two CCSW pumps in less than this period of time. This pump sequencing serves to limit the load imposed on a diesel generator. Utilization of the LPCI subsystem in conjunction with containment cooling service water would achieve the containment cooling capability as specified in Section 6.2.1.3.2.2.

During LPCI subsystem operation, water is normally taken from the suppression pool and is pumped into the core region of the reactor vessel via one of the two recirculation loops. There is also a connection to the contaminated condensate storage tanks to make condensate available as a backup supply. In the event of a recirculation line break, instrumentation is provided to select the undamaged flow path for injection of the required LPCI flow into the reactor vessel. This instrumentation also causes appropriate valves to close which could otherwise result in spillage of the LPCI flow from the shroud region. The sensing circuit for break detection and loop selection is arranged so that failure of a single device or circuit to function on demand will not prevent correct selection of the loop for injection. All components of the loop selection network are operated from dc power sources so that loop selection can take place irrespective of the availability of ac power. LPCI loop selection logic and instrumentation is described in Section 7.3.

6.3.2.2.3 Equipment Characteristics

6.3.2.2.3.1 Low Pressure Coolant Injection Pumps

The LPCI pumps were sized on the basis of the flow requirements for the LPCI subsystem. These are the maximum subsystem flow requirements and were calculated from the rate of coolant loss due to a maximum credible break in the primary system piping. This flowrate calculation considered shroud leakage.

The shroud and jet pumps form an inner vessel which must be sufficiently leaktight, despite thermal expansion allowances, to permit reflooding the core to a level adequate for core cooling following a DBA LOCA. The expected leakage is a function of time and water level in the core. The first leakage path is the bolted joint at the top of the jet pump riser, and the second is the slip fit between the jet pump throat and diffuser sections. A potential leakage path at the jet pump to the baffle plate joint is precluded by a completely seal welded joint. A third leakage path exists on Unit 2 at the access hole cover joints in the shroud support baffle plate. The Unit 2 access holes have been modified to a bolted design versus the original welded configuration.

The leakage path at the bolted joint at the top of the jet pump riser is a function of time because the force holding the mating parts together is a function of the differential thermal expansion in the holddown bolt relative to the jet pump "rams head." Early in the transient the bolts will be extended relative to the rams head because the bolts will tend to remain at about 545°F while the rams head will cool off rapidly during LPCI injection. The bolt will cool within a few minutes, however, thereby retightening the joint. The jet pump bolted joint by analysis has been shown to leak no more than 582 gal/min for the 10 pumps through which the vessel is being flooded. The leakage path between the jet pump throat and diffuser sections is a function of water level only since the level is the only driving force for the leakage. This leakage path is not a function of time since both parts of the joint will thermally expand and contract together. The slipjoints for all 20 jet pumps will leak no more than 225 gal/min. Leakage through the Unit 2 access hole covers is a function of water level only since the differential level is the only driving force for the leakage. The leakage is not a function of time since the access hole cover and shroud support baffle plate expand and contract together. The bolted joints for the two access hole covers in the Unit 2 shroud support plate have been analyzed and shown to leak no more than 78 gal/min total for both covers.

Although the LPCI system capacity was sized to accommodate 3000 gal/min leakage at these three locations, the calculated maximum combined leakage is 885 gal/min for Unit 2 and 807 gal/min for Unit 3.

The 3000 gal/min leakage rate from inside the shroud through the jet pumps is a design number for all BWR jet pump plants for the purpose of sizing the LPCI pumps. This design basis is based on early estimates of the shroud leakage rate when the water level is at two-thirds core height. These estimates were performed in a most conservative fashion to arrive at a jet pump leakage rate which could be applied to any BWR jet pump system without exceeding the actual expected leakage rate of any particular plant. Thus, the basis for the assumption of 3000 gal/min leakage from the jet pumps during LPCI operation with the water level at the two-thirds core height is simply to provide a conservative allowance for leakage which may be applied in the design of any LPCI system, allowing "decoupling" of the LPCI pump design and the jet pump component design.

The LPCI pump motors utilize normal auxiliary ac power when it is available and are also connected to the diesel generators to ensure availability in the event normal ac power is lost. Each pump has a 700 hp rating at a service factor of 1.0. All of a unit's four LPCI pumps will be used when operating in the accident mode. However, as discussed in Section 6.3.2.2.2, the DBA LOCA analysis takes credit for two or four LPCI pumps. If normal power is not available, two pumps will receive power from the unit diesel generator and two from the 2/3 diesel generator.

6.3.2.2.3.2 Valves

Isolation valves are located on the LPCI subsystem piping since this system penetrates the primary system. There are two separate injection points in the primary recirculation loop for the LPCI subsystem flow, and since the core spray subsystem is concurrently placed in operation, no special valving redundancy is provided. The isolation valves provide protection against core uncoverage if the LPCI piping were to break. The isolation valves also serve to protect the LPCI subsystem against high reactor pressure in case of a component malfunction. The isolation valves are designed and constructed to achieve the highest possible reliability and to withstand maximum reactor vessel temperature and pressure. The speed and response of the LPCI injection valves and primary recirculation loop isolation valves are compatible with LPCI subsystem objectives.

The crosstie line between the two LPCI loops contains two motor-operated valves. Gate and check valves are located on the pump discharge lines, and flow control valves are provided on the lines where flow adjustment is necessary. Check valves located in the containment are equipped with operators to permit exercising and testing during normal plant operation.

When the HPCI system is operated, the suppression chamber water level rises. The normal level can be restored by opening LPCI subsystem valves (two control-room-operated automatic isolation valves) and discharging water to the condenser hotwell or to the floor drain collection tank.

Gate and butterfly valves are located where necessary to permit maintenance on the system. These are normally locked open.

6.3.2.2.3.3 Piping and Fittings

Two independent pipe lines are each sized for full LPCI subsystem flow, thereby providing redundancy in flow paths for LPCI operation. These lines are physically separated and protected as much as practical.

The piping is carbon steel, except for the stainless steel piping from the isolation valves to the reactor system. All LPCI subsystem components are designed in accordance with applicable codes for reactor auxiliary systems.

Breaks in the LPCI injection line between the check valve and the recirculation loop would be detected as a loss-of-coolant accident. These breaks are equivalent to recirculation discharge line breaks of the same size in the same loop. Since the LPCI injection line is smaller than the recirculation discharge line, the LPCI line break is bounded by the DBA LOCA. The drywell sump pump method is capable of detecting leakage in the LPCI line. Unidentified leakage in excess of 5 gal/min would result in plant shutdown within 24 hours to determine the cause of the leak.

Because the low pressure ECCS piping outside the drywell up to the first outside isolation valve is considered an extension of the primary containment, the LPCI subsystem piping must meet the same design, surveillance, and testing criteria as the primary containment. Rupture of this low pressure piping is, therefore, extremely unlikely. The location and identification of such leaks would be through room temperature alarms, reactor building floor drain sump activity, and visual inspection (since these lines are accessible).

All leakage in the ECCS outside the primary containment can be isolated from the suppression chamber and the primary system itself.

The discharge piping of the LPCI subsystem is required to be filled and vented in order for the subsystem to be considered operable. The vent pathway for LPCI is through vent valves and a sight glass to the reactor building floor drains. The fill system is used to ensure that the LPCI discharge lines remain pressurized. This fill system consists of a core spray jockey pump described in Section 6.3.2.1.2. If the jockey pump is removed from service for maintenance, the condensate transfer system can be used as an alternate fill system.

During the In-Vessel Visual Inspection of D2R15, a flaw was identified on the jet pump riser between jet pumps 15 and 16 at the reactor vessel nozzle thermal sleeve to elbow weld. An evaluation was performed that calculated LPCI system leakage that would be lost through the flaw during the DBA LOCA and the effects of that leakage on the peak fuel cladding temperature. Monitoring of the condition of this weld will be performed as recommended by BWRVIP-41 and the applicable ASME Section XI Flaw Evaluation.

6.3.2.2.3.4 Instrumentation

The LPCI subsystem is initiated on any of the following signals as discussed in Section 7.3:

A. High drywell pressure;

B. Low-low reactor water level coincident with low reactor pressure; or

C. Low-low reactor water level coincident with timeout of the ADS high drywell pressure bypass timer.

Logic is provided to ensure the LPCI flow is injected into the unbroken recirculation loop. A detailed description of LPCI subsystem loop selection instrumentation, logic, and minimum flow valve operation is provided in Section 7.3. See Table 6.3-20b for minimum detectable break size for LPCI loop select logic assumed in the GE LOCA analysis and Table 6.3-20c for Westinghouse analysis.

Interlocks are provided to prevent LPCI flow from being diverted to the containment cooling subsystem piping unless the core is flooded to at least two-thirds of its height. Sections 6.2.2 and 7.4 provide a more detailed description of containment cooling interlocks.

Instrumentation provided for monitoring LPCI subsystem operation includes LPCI pump suction and discharge pressure, LPCI flow to recirculation loop, LPCI minimum flow (% rated flow), and LPCI loop select logic jet pump riser differential pressure.

6.3.2.2.4 LPCI Operating Sequence

6.3.2.2.4.1 LPCI Operating Sequence with Plant on Normal Auxiliary AC Power

Upon receipt of an initiation signal with normal ac power available, the following sequence automatically occurs:

A. Diesel generators start;

B. Permissive available to activate pumps and valve;

C. All four LPCI pumps start without delay;

D. Pump suction valves open (if closed). The pump suction valve opening signal can be overridden such that the valves can be closed if necessary to isolate a leak; and

E. Containment cooling service water pumps stop (if running).

When the reactor primary system pressure drops to the shutoff head of the LPCI pumps, a check valve in the LPCI injection line opens. Prior to this time, the LPCI control system would have sensed the loop in which the break has occurred, closed the recirculation line pump discharge valve in the unbroken loop, and opened the LPCI injection valve to the unbroken recirculation line.

6.3.2.2.4.2 LPCI Operating Sequence with Diesel Generator

Upon receipt of an initiation signal coincident with a loss of normal ac power, the following sequence occurs:

A. Diesel generators start;

B. Permissive available to activate pumps and valves;

C. Pump suction valves open (if closed);

D. After the diesel generators restore power to their respective buses, LPCI pumps A and C receive a start signal;

E. After completion of a time delay (the allowable value for this time delay is specified in the Technical Specifications) LPCI pumps B and D receive a start signal. (See Table 6.3-4b.)

LPCI flow to the vessel is established as previously described in Section 6.3.2.2.4.1.

6.3.2.3 High Pressure Coolant Injection Subsystem

The HPCI subsystem is designed to pump water into the reactor vessel under those LOCA conditions which do not result in rapid depressurization of the reactor pressure vessel. The loss-of-coolant might be due to a loss of reactor feedwater or to a small line break which does not cause immediate depressurization of the reactor vessel.

The HPCI subsystem includes a steam turbine driving a two-stage high pressure pump and a gear-driven, single-stage booster pump, valves, high pressure piping, water sources, and instrumentation. The HPCI subsystem is shown in Drawings M-51 and M-374. The HPCI equipment specifications are shown in Table 6.3-7.

The subsystem piping was designed to USAS B31.1 and ASME Section I. The pumps were designed to ASME Section III. The piping arrangement includes considerations for potential damage, and open piping runs are protected by structural steel. Fabrication, testing, and inspection of this piping was equal to that required for the primary containment system.

Operation of the HPCI system in the emergency mode is completely independent of ac power with the exception of the HPCI room cooler fans, and requires only dc power from the station battery to operate the controls.

Operation of the HPCI subsystem is dependent upon reactor water level signals (Figures 7.3-8A, 8B, and 8C). Either low-low water level or high drywell pressure starts the subsystem and high water level stops it.

The LOCA analysis by Westinghouse at 2957 MWt for SVEA-96 Optima2 fuel analyzed the entire break spectrum. This analysis included the various combinations of single failures as described in Table 6.3-21c. The HPCI turbine oil cooler and gland seal condenser are cooled by water from the suppression pool. Since these components are rated at 140 °F, continued operation above a suppression pool temperature of 140 °F is not permitted. Also, operation of HPCI above 140 °F would exceed the current net positive suction head (NPSH) calculations for rated HPCI pump flows. Another limitation on the HPCI system is related to the dependence of the HPCI room cooler on the unit emergency diesel generator (EDG). Therefore, any single failures of the unit EDG need to assume consequential loss of the HPCI system after 10 minutes of operation. As a result of these considerations, the HPCI system is not credited when any of these conditions are exceeded. The results of the analyses show that the HPCI system met its requirements before the 10 minute mission time was exceeded and the suppression pool temperature exceeded 140 °F (see Reference 78).

6.3.2.3.1 High Pressure Coolant Injection Interface with Other Emergency Core Cooling Subsystems (Historical)

Under current regulatory requirements, the function of the HPCI subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Tables 6.3-21b and 6.3-21c list the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the HPCI subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

The sizing of the HPCI subsystem is based upon providing adequate core cooling during the time that the pressure in the reactor vessel decreases to a value where the core spray subsystem and/or the LPCI subsystem become effective.

6.3.2.3.2 Subsystem Characteristics

Suction for the HPCI pump is normally taken from both contaminated condensate storage tanks, where 90,000 gallons of water are reserved by administrative control for HPCI. On low-low level in the contaminated condensate storage tank or high level in the torus, the HPCI suction will automatically switch to the suppression pool.

The discharge piping of the HPCI subsystem is required to be filled and vented for the subsystem to be considered operable. With HPCI suction aligned to a contaminated condensate storage tank (CCST), keep fill is provided by the head of the CCST. If HPCI suction is aligned to the torus, ECCS keep fill must be aligned to the HPCI discharge line.

The water from either source is pumped into the reactor vessel through the feedwater sparger to obtain mixing with the hot water in the reactor pressure vessel. Water leaving the vessel through a line break drains by gravity to the suppression pool. The LPCI subsystem in conjunction with the containment cooling service water system is required for cooling of the suppression pool after several hours of HPCI subsystem operation.

The HPCI subsystem is designed to pump 5600 gal/min into the reactor vessel within a reactor pressure range of about 1135 psia to 165 psia. However, the HPCI flow assumed in the GE LOCA analysis is 4400 gal/min. The Westinghouse LOCA analysis uses 5000 gal/min HPCI flow between 1120 psi and 150 psi vessel overpressure. The turbine is driven with steam from the reactor vessel. As reactor pressure decreases, the control valves throttle to pass the required steam flow to maintain the set pump flowrate. Turbine speed is controlled by the motor speed changer (MSC) and the motor gear unit (MGU) described in Section 7.3.1.3.2.

The HPCI flowrate is measured in the pump discharge line. A conventional flow controller compares this measured flowrate with a preset flow requirement of 5600 gal/min. The output of the flow controller will vary from 4 to 20 milliamps, depending on where (i.e., at what speed) the flow demand is satisfied. The controller output is fed to the turbine control (MGU) logic for turbine-pump speed control and, therefore, ultimate flow control.

The controlling design condition for the turbine steam path is the low pressure operation point, i.e., developing the required horsepower (1350 hp at 2250 rpm) with 155 psia inlet steam pressure and 65 psia exhaust pressure. This operating condition (maximum volume flow) dictates the required turbine stage areas. All other operating conditions require less volume flow and, therefore, result in throttling the turbine control valves. This control function is no different than that encountered in boiler feed pump drive systems.

Exhaust steam from the unit is discharged to the suppression pool. The turbine exhaust line is provided with a vacuum breaker system. The vacuum breakers were added to improve turbine low-load operation, to minimize pressure fluctuations, and to prevent suppression pool water rise in the exhaust line which would result in unacceptable back pressure during the turbine startup transient.

The turbine gland seals are vented to the gland seal condenser, and water from the HPCI booster pump discharge is routed through the gland seal condenser for cooling purposes. Noncondensible gases from the gland seal condenser are ducted to the standby gas treatment system.

Moisture removal systems are provided both in the steam supply line near the turbine, in the turbine exhaust line, and in the turbine casing. The systems use conventional equipment consisting of collection drain pots and steam traps.

Moisture removal from the HPCI turbine steam supply eliminates water slug buildup, thereby permitting rapid start of the unit without warmup. The steam supply line up to the steam shutoff valve located directly upstream of the turbine stop valve is maintained at reactor pressure and temperature. A water collection pot is located upstream of the steam shutoff valve and is drained through a choke trap to the main condenser during normal plant operation. Upon receipt of a HPCI initiation signal, the condensate drain to the main condenser is automatically isolated and diverted to the suppression pool.

Provisions have been made to provide protection against possible failure of the choke trap. An automatic bypass is provided around the trap, actuated by a level sensing switch in the drain pot. Should the choke trap fail to pass water, condensate will collect in the drain pot. The level switch will automatically open the steam bypass valve prior to the condensate level reaching the bottom of the steam line.

A conventional drain collection pot is used to drain the turbine exhaust line, turbine casing drains and moisture collecting downstream of the stop valve. This pot is normally drained to the suppression pool. An automatic level controlled bypass provides gravity draining to the gland seal condenser.

Steam line valve closure logic, as described in Section 7.3, is provided to initiate isolation of the HPCI steam line should abnormally high steam line flow, low steam line pressure, or high HPCI area temperature conditions be experienced. The turbine is rated for a reactor vessel steam flow of 145,000 lb/hr 1135 psia and 102,500 lb/hr of steam at 165 psia.

The HPCI steam supply inboard containment isolation valve, 2(3)-2301-4, is provided with throttle open capability which allows a gradual pressure increase in the steam inlet line to the HPCI turbine. The valve control switch and relay provide a throttle open, seal-in on close, spring return to AUTO feature, with a PULL-TO-LOCK function 90° from center. The PULL-TO-LOCK function of the 2301-4 valve switch is capable of closing the valve during subsystem operation and defeating the automatic mode of the HPCI subsystem. The primary sensors to automatic initiation of HPCI (drywell high pressure and reactor low-low water level) are not affected by this change.

The HPCI system can be tested for operability (see Section 6.3.4.3.3) by returning the pump discharge flow to the condensate storage tank (CST) via the safety related 250-Vdc-powered full flow test valve 2301-10. The test bypass valve (2301-10) is a high-pressure, multi-stage valve designed to avoid cavitation. To ensure non-coincident motor initiation of the test bypass valve with the HPCI injection valve (2301-8), an auxiliary relay is included in the full flow test valve circuitry. This limits the load on the safety related 250-Vdc battery system.

The lube oil for the HPCI pumps and turbine is cooled by water taken from the HPCI booster pump discharge line. The HPCI pump is turbine driven and, hence, no external power is needed for cooling water under accident conditions.

However, for preoperational warmup in the test mode using a controlled startup procedure rather than an emergency auto startup, the subsystem has a cooling water pump which can be used only when normal ac power is available.

A minimum flow bypass system returns a portion of the pump discharge flow back to the suppression chamber for pump protection. The bypass valve is automatically opened on low pump flow and closed on high flow whenever the steam supply valve to the turbine is open.

The HPCI pump suction valves are interlocked to prevent opening the valve from the condensate storage tank whenever both valves from the suppression chamber are fully open. The test return valves to the condensate storage tank are also interlocked closed when either suction valve from the suppression chamber is not fully closed.

Instrumentation provided for monitoring HPCI operation includes main pump discharge temperature, turbine oil temperature, booster pump suction pressure, main pump discharge pressure, turbine inlet and outlet pressure, gland seal pump discharge pressure, turbine lube oil and hydraulic oil pressures, steam supply pressure, HPCI flow (% rated water flow), and HPCI steam line flow ΔP.

6.3.2.3.3 High Pressure Coolant Injection Operational Sequence

6.3.2.3.3.1 High Pressure Coolant Injection Automatic Initiation

Initiation of the high pressure coolant injection subsystem occurs on signals indicating reactor low-low water level or high drywell pressure. These signals and their associated logic are discussed in detail in Section 7.3.

Upon receipt of the initiation signal, the HPCI turbine and its required auxiliary equipment such as the auxiliary oil pump and gland seal leakoff blower, automatically start. The automatic HPCI turbine trip due to low booster pump suction pressure is bypassed if an initiation signal is present. In addition, the following valves assume or maintain the following positions:

A. Steam supply line containment isolation valves open, if closed (these are normally open valves);

B. Turbine steam supply and stop valves open;

C. Pump suction valve from the condensate storage tank opens if closed (normally open);

D. Pump discharge valves open (one valve is normally open); after the pump discharge pressure reaches a preset value to prevent steam flashing and water hammer;

E. Cooling water return valve to the HPCI booster pump suction opens;

F. Steam line drain valves to the main condenser close and the steam line drain valve to the suppression chamber opens;

G. Turbine stop valve drain valves close;

H. Cooling water return valve to condensate storage tank closes; and

I. Test return valves to condensate storage tank close (if open). Note: the 2301-10 test bypass valve closing logic includes an interposing relay which delays the closing of the valve by approximately 40 milliseconds to limit loading on the battery system.

6.3.2.3.3.2 High Pressure Coolant Injection Automatic Isolation and Shutdown

Shutdown of the HPCI subsystem may occur in either of two ways: isolation of the steam supply to the turbine or tripping the turbine stop valve closed. It should be noted that with the turbine stop valve leaving the full open position, the turbine control valves close automatically. A description of the HPCI subsystem shutdown signals and logic is provided in Section 7.3.

The steam supply isolation will occur upon receipt of a high steam line flow, high area temperature, or low steam line pressure. Turbine stop valve closure will occur upon receipt of a turbine overspeed trip, low booster pump suction pressure, high turbine exhaust pressure, or reactor vessel high water level.

A steam leak from the HPCI line, outside the primary containment, in the HPCI room would result in high room temperature which would then result in HPCI isolation and an alarm in the control room. A steam leak of sufficient magnitude would result in a high HPCI steam flow isolation and annunciation. If HPCI does not automatically isolate due to high steam flow then, upon detection of the leak, the operator may close the HPCI steam line isolation valves to terminate the leak.

Leakage from the HPCI subsystem discharge line which leads to the feedwater line would be condensate storage tank or suppression pool water and, as such, the leakage would not flash to steam.

Table 6.3-21b shows the single failure scenario analyzed in the GE LOCA. For the GE analysis, additional failure of HPCI for each scenario will not meet the 10 CFR 50.46 criteria.

The LOCA analysis by Westinghouse for SVEA-96 Optima2 fuel analyzed the entire break spectrum. This analysis included the various combinations of single failures as described in Table 6.3-21c. The SVEA-96 Optima2 analyses assume that HPCI is available within operability constraints unless it is the assumed single failure.

6.3.2.3.3.3 High Pressure Coolant Injection - Continuous Operation

Operation of the HPCI turbine continues as long as reactor pressure is above 165 psia and reactor water inventory has not returned to normal. Components are designed to maintain constant flow as the pressure is reduced. The HPCI subsystem automatically maintains reactor water level between low-low level and high level if the break size is within the capacity of the pump and the reactor is not depressurized below 165 psia.

6.3.2.3.3.4 High Pressure Coolant Injection - Termination of Operation

When the reactor pressure falls below 165 psia, the speed of the turbine-pump unit will begin to decrease and will gradually be slowed to a stop by friction and windage losses at a reactor pressure of about 65 psia; however, HPCI isolation will automatically occur on low reactor pressure of 100 psig. This isolation setpoint occurs at or above the pressure at which the turbine would stop due to friction and windage losses.

Core cooling at this time will be accomplished by the core spray subsystem and the LPCI subsystem. For a small break, core cooling will be maintained by the control rod drive pumps if ac power is available.

6.3.2.4 Automatic Depressurization System

6.3.2.4.1 Automatic Depressurization Subsystem Interface with Other Emergency Core Cooling Systems (Historical)

Under current regulatory requirements, the function of the ADS subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. Tables 6.3-21b and 6.3-21c list the ECCS equipment available under different postulated single active failure considered in Appendix K ECCS performance evaluation (see Section 6.3.3). This section presents historical information on the interface between the ADS subsystem and other ECCS subsystems under the original design. The information is historical and is not needed to support the current design basis.

The ADS is an ECCS subsystem which is employed as a backup to the HPCI subsystem to depressurize the reactor pressure vessel for small area breaks. The HPCI subsystem provides primary depressurization and core cooling for small breaks. In the event that HPCI is not effective, the ADS reduces pressure by blowdown through automatic opening of the relief valves to vent steam to the suppression pool. For small breaks the vessel is depressurized in sufficient time to allow core spray or LPCI to provide adequate core cooling. For large breaks the vessel depressurizes through the break without assistance. Pressure relief of the reactor vessel may be accomplished manually by the operator or without operator action by the ADS circuitry. Additional ADS logic information is provided in Section 7.3.

6.3.2.4.2 Subsystem Characteristics

The ADS is designed to automatically actuate to depressurize the reactor vessel if the following conditions A and B and C are met for 120 seconds or if conditions C and D are met:

A. Low-low reactor water level,

B. High drywell pressure,

C. At least one LPCI or one core spray pump with discharge pressure exceeding 100 psig.

D. Low-low reactor water level (continuous for 8.5 minutes), in conjunction with Condition C.

The 120-second ADS time delay prevents unnecessary blowdowns resulting from transient conditions and provides an opportunity for HPCI to restore reactor water level. The ADS timer logic is discussed in Section 7.3.

The time delay also provides surveillance time in which the operator can evaluate possible spurious activation signals. A permissive signal from the time delay circuit serves as the confirming signal to activate the relief valves when the control station switch is in the automatic position. The delay time setting before the ADS is actuated is chosen to be long enough so that the HPCI has time to start, yet not so long that the core spray and LPCI are unable to adequately cool the fuel if the HPCI fails to start. All of the five relief valves (four electromatic relief valves and one Target Rock safety/relief valve) normally open simultaneously; however, two of the electromatic relief valves are equipped with additional control logic and are subjected to an additional valve reopening delay (Analytical Limits: 8.5 to 11.5 seconds) to preclude immediate automatic reopening of valves that were previously opened. This delay will prevent excessive loading as a result of an elevated water leg in the relief valve discharge piping (see Section 5.2.2.2). An ADS inhibit switch is provided to prevent ADS actuation during an anticipated transient without scram (ATWS) event or whenever the emergency operating procedures require an ADS override. Manual blowdown of the reactor vessel is accomplished independently of the automatic circuitry.

Excessive vessel pressure is automatically relieved by circuitry which supplies a direct signal to the auxiliary relay to actuate the relief valves (Section 5.2 provides a description of the relief valves and associated reactor vessel high pressure relief controls). The vessel high pressure relief function is not performed by the ADS subsystem.

Based upon an ADS spurious actuation study which was initiated to meet the NRC's circuit failure mode interpretation of 10 CFR 50, Appendix R requirements, further separation of ADS cabling was mandated. The study revealed that certain combinations of short circuits would result in the spurious operations of the five relief valves. To reduce the probability of spurious actuation, the control cable of concern was replaced by two cables to provide separation such that multiple shorts within cables associated with ADS would not cause spurious operation of multiple valves.

6.3.3 Performance Evaluation

6.3.3.1 Emergency Core Cooling Subsystem Performance Evaluation

The original design basis of the ECCS subsystems was to prevent fuel clad melting over the entire spectrum of postulated primary coolant leaks. The range of break sizes for which each of the emergency core cooling systems was deemed capable of protecting the core against clad melting is shown in Figure 6.3-1. Figure 6.3-1 shows the range of break sizes for which an ECCS subsystem was deemed capable of preventing clad melting without assistance from and in conjunction with any other subsystems (See Section 6.3.3.3.1 for further discussion).

Under current regulatory requirements, the function of each ECCS subsystem is to ensure adequate core cooling across the entire spectrum of line break accidents when operated with other available ECCS subsystems determined from the Appendix K single active failure criterion. The integrated performance of the ECCS system is evaluated using an approved Appendix K ECCS evaluation model (see Section 6.3.3.3). A system by system performance evaluation is no longer needed. This section provides the historical performance evaluation of each ECCS subsystem. Tables 6.3-1 and 6.3-2 list the ECCS parameters used in the evaluation. The information in this section is historical and is not needed to support the current design basis.

6.3.3.1.1 Core Spray Subsystem (Historical Information)

Each core spray subsystem is designed to maintain continuity of reactor core cooling for a large spectrum of loss-of-coolant accidents. Each subsystem provides adequate cooling for intermediate and large line break sizes; however, either two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA. The integrated performance of a core spray subsystem in conjunction with other emergency core cooling subsystems is provided in Section 6.3.3.3.

As indicated previously, there exists a break size below which the core spray subsystem alone cannot protect the core (see Figure 6.3-1). Vessel pressure does not drop rapidly enough to allow sufficient core spray injection to occur before the fuel cladding reaches an excessively high temperature. Below this break size either HPCI or ADS extends the range of the core spray subsystem to breaks of insignificant magnitude.

The core spray heat transfer tests were completed and are reported in Reference 2. These tests covered fuel bundles having an initial power level of 6.5 MWt, well in excess of the peak bundle power for the units. The test fuel rods were allowed to overheat (1600°F) prior to core spray activation. Actual core spray operating temperatures of 2350°F were tested, well in excess of the 10 CFR 50.46 allowable PCT of 2200°F.

Bundle flowrates from 0.5 gal/min to over 3.25 gal/min were tested including the 2.45 gal/min minimum measured flowrate for the spray distribution. Flows into the bundle as low as 0.5 gal/min effectively cooled the rods. A more detailed discussion is given in Reference 2. Considerable margin exists between the minimum flows required for cooling the fuel rods and the flow actually being injected.

Core spray distribution tests were performed to determine a core spray nozzle arrangement and aiming angles such that every fuel assembly in the core would receive an adequate amount of water during core spray operation. Adequate flow is defined as 2.45 gal/min per fuel assembly. Tests were conducted for both the upper and lower spray ring sparger. The effects of sparger flow, aiming angle tolerances, and updraft were investigated thoroughly.

Tests were run with flows as low as 4100 gal/min and as high as 5850 gal/min. The flow distributions achieved are shown in Figure 6.3-10.

Aiming angles for the full jet and open elbows were determined for both the upper and lower sparger. Variations in nozzle aiming angle, updraft velocity, and core spray flowrates were tested to determine the sensitivity to the variables. Both upper and lower spargers gave the same result.

Updrafts expected in the core have been demonstrated [2,3] to be in the range where they will have little or no effect on the overall core spray distribution. Figure 6.3-11 illustrates the core updraft effect.

Performance analyses of the reactor core spray subsystem are based on an analytic prediction of the reactor vessel pressure and mass inventory as a function of time following a postulated rupture of the coolant system piping. These analyses are conducted with a digital computer code (see Section 6.3.3.2.2) which includes such effects as main steam flow, leakage flow from the break, stored energy release, and decay heat from the reactor core, as well as any other inflows or outflows from the system due to the operation of the ECCS. The various mass and energy flows make up the terms of mass, energy, and volume balance equations for the saturated reactor vessel fluid. Simultaneous solution of the equations are used to define the state within the reactor vessel at any time. In all cases, the analyses are begun with the coolant system liquid inventory at low-level scram and the reactor operating at full power for the turbine design condition. For all loss-of-coolant analyses the break is assumed to occur instantaneously and simultaneously with the loss of normal auxiliary power.

The results of a performance analysis of a typical break size within the range of the unassisted reactor core spray subsystem is shown in Figure 6.3-12. For the first few seconds the feedwater and recirculation pumps coast down providing makeup to the vessel. Recirculation flow during this period is nearly normal. Reactor pressure is initially held up primarily due to the action of the turbine initial pressure regulator. During this time the water level outside the shroud is decreasing rapidly because of the high critical flowrate through the break. The water level inside the shroud is maintained at the steam separators while the stored heat is removed and the voids are swept from the core region. When the water level inside the shroud reaches the top of the jet pump inlet (two-thirds core height), the level is held up.

Further decreases in level inside the shroud are the result of flashing due to depressurization and boiloff. As the level outside the shroud drops below the suction side vessel penetration of the recirculation loop, the level is held up in the unbroken loop. As the broken recirculation loop is completely drained of liquid, the break flow changes to steam which causes an increase in the vessel depressurization rate. When the vessel pressure decreases to below the shutoff head of the core spray subsystem, core spray injection begins. For a short time the core spray flow is in equilibrium with the flashing rate and the water level inside the shroud is constant. As core spray flow increases due to the decreasing pressure, the water level inside the shroud increases. When the water level in the jet pumps reaches the top of the jet pumps, water spills over from inside the shroud to outside the shroud slowly raising the water level in the unbroken loop. The water level inside the shroud is slightly above the jet pump inlet due to the higher void fraction in the core compared to that in the jet pumps. The water level inside the shroud continues to rise slowly due to the decreasing pressure and corresponding increase in core void fraction.

See Section 6.3.3.3.2 for core spray long term cooling requirements.

In conclusion, the core spray subsystem provides an effective means of terminating the core heatup transient (in conjunction with HPCI or ADS for small breaks) over a wide spectrum of loss-of-coolant accidents. Note, however, the two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA. Experimental and analytical techniques have shown that steam updrafts expected in the core are in a range which will have little or no effect on the amount of spray flow entering a channel. Section 6.3.3.3 presents a detailed discussion of the integrated performance of the core spray system in conjunction with other emergency core cooling subsystems.

6.3.3.1.2 Low Pressure Coolant Injection Subsystem (Historical Information)

The LPCI subsystem is designed to provide reactor core cooling for a large spectrum of loss-of-coolant accidents. The LPCI subsystem is capable of providing adequate cooling for intermediate and large line break sizes; however, either two core spray subsystems or one core spray subsystem and two LPCI pumps are required to ensure adequate core cooling following a DBA LOCA. A detailed discussion of the integrated performance of the LPCI subsystem in conjunction with other emergency core cooling subsystems is given in Section 6.3.3.3.

The LPCI pumps are designed to have both adequate head and adequate coolant flow capacity to meet flooding requirements, when operating in conjunction with either the HPCI or ADS system.

The maximum LPCI flow capacity (14,500 gal/min at a differential pressure between the suppression pool and the reactor pressure vessel of 20 psid with three pumps running) is determined by the original FSAR design basis break (instantaneous break of a recirculation line). The pumps are capable of refilling the inner plenum in time to ensure adequate core cooling, assuming no water remains after blowdown. The minimum allowable time in which this must be done is based on the design basis break because the least core cooling occurs for this break. Hence, the core must be reflooded more quickly than for small breaks. However, the vessel depressurizes very quickly for this break size and therefore a greater quantity of water can be pumped to the vessel due to the LPCI pump head-flow characteristic.

The maximum vessel pressure against which the LPCI pumps must deliver some flow was determined in the original FSAR by the required overlap with HPCI which has a low pressure cutoff for the HPCI subsystem turbine at about 150 psig. The LPCI subsystem can pump about 8000 gal/min (about half of the maximum flowrate) at a differential pressure between the suppression pool and the reactor pressure vessel of 200 psid and, in conjunction with the HPCI subsystem, LPCI can provide adequate coverage for the intermediate and smaller breaks over the entire pressure range. The required LPCI pump head characteristic for a range of conditions is shown on Figure 6.3-8.

The performance analysis at 2527 MW_t of the LPCI subsystem in the original FSAR for a typical break size within the capability of the unassisted LPCI subsystem is shown in Figure 6.3-13. Note that this analysis is for a three LPCI pump operation even though all four LPCI pumps normally start in response to an initiation signal. The phenomena during the first phases of the transient before the LPCI subsystem becomes effective are seen in Figure 6.3-13 to be the same as for the core spray subsystem performance analysis discussed in Section 6.3.3.1.1. The analytical model is described in detail in Section 6.3.3.2.2.

In the original FSAR analysis, operation of the LPCI pumps, closure of the recirculation line pump discharge valve in the unbroken loop, and opening the check valve and LPCI injection valve to the unbroken recirculation line provides an integral flow path for the injection of the LPCI flow into the bottom plenum of the reactor vessel. As the LPCI flow accumulates, the level rises inside the shroud. When the level reaches the top of the jet pumps, spillover occurs for a time raising the level outside the shroud. As the subcooled LPCI flow begins spilling into the region outside the shroud, the depressurization effect of the break is reduced since the subcooled water is now flowing out the break.

In the original FSAR analysis, as the pressure begins to rise, the LPCI flow is reduced until a quasi-equilibrium pressure is reached. At this point the break is partially covered by subcooled water which has spilled over the top of the jet pumps and the equivalent area of the break available for steam blowdown is thus reduced. The size of the break available for steam blowdown is maintained at the required equilibrium value by the LPCI spillage. If pressure were to rise, the LPCI flow would be reduced, the equivalent break size for steam blowdown would increase, and the pressure would drop. Complete equilibrium is reached when the rate of saturating the LPCI water becomes equal to the boiloff rate.

It is noted that this condition will not actually be attained due to the HPCI and ADS effects on the transient. Also, In the original FSAR analysis, at 2527 MW_t, no credit is taken for the pressure reduction affect of the cold LPCI water in the reactor vessel.

There exists a break size below which the LPCI subsystem requires depressurization assistance to maintain core cooling. For these small breaks, the HPCI and ADS subsystems provide the necessary depressurization to allow LPCI to provide adequate core cooling.

During LPCI injection, the minimum flow valve in the non-selected loop will remain open to ensure a pump flow path. The valve remains open because the "A" loop flow sensor controls only the "A" loop valve, and similarly, the "B" loop sensor controls only the "B" loop valve. This logic permits one of the LPCI pump minimum flow bypass lines to remain open, during a LOCA. As a result, there is a reduction in LPCI flowrate to the core by an amount equivalent to the flowrate through the minimum flow line. The 10 CFR 50 Appendix K at 2527 MW_t analysis assumes a two pump LPCI flowrate of 9000 gal/min for the DBA LOCA with a diesel generator failure. The minimum flow of the non-selected loop is subtracted from this assumed flow rate. For operation at 2957 MW_t, the LOCA analysis [70] used SAFER/GESTR-LOCA methodology with bounding input parameters from the combination of the Dresden and Quad Cities plants [76]. The significant parameters used in the analysis to support operation at 2527 MW_t for GE14, 9x9-2 and ATRIUM-9B fuel types are summarized in Table 6.3-20b. Based on actual station test data obtained with the minimum flow valves open, the minimum LPCI flowrate assumed by the current accident analysis was verified.

6.3.3.1.3 High Pressure Coolant Injection Subsystem

The high pressure coolant injection subsystem has been evaluated to assure that the design bases are met. This evaluation considers the structural integrity of the HPCI subsystem to withstand the effects of an accident for which the subsystem must be available. The suitability of valves, pump and turbine sequencing, speed of operation, capacity, and the depressurization efficiency for HPCI flow were also evaluated.

6.3.3.1.3.1 High Pressure Coolant Injection Subsystem Availability

To inject water at a high pressure, three major active components must operate. A motor-operated valve must open to admit steam to the turbine driving the pump, a motor-operated valve must open to admit the discharge flow from the pump into the reactor feedwater line, and the turbine driven pump itself must operate. Section 6.3.2.3.3.1 identifies additional HPCI components required to ensure proper HPCI system operation.

The turbine driving the pump is designed especially for this type of service. It operates over a wide range of inlet and exhaust pressures and the construction is such that it can start cold and come to full power operation almost instantaneously. The HPCI turbine is essentially identical to numerous units in service as boiler feed pump drives. Steam pressure is available to drive this pump whenever high pressure injection is needed. The HPCI subsystem can be tested frequently so that any operating deficiencies can be detected early.

Operation of the HPCI subsystem is automatic and requires no manual intervention.

Table 6.3-21b shows the single failure scenario analyzed in the GE LOCA. The single failure scenario analyzed in the Westinghouse LOCA is shown in Table 6.3-21c.

There are many actions the operator can take to prevent core damage for moderate size breaks. If normal sources of power are available, the operator can continue to operate the regular feedwater pumps to provide makeup. The operator can transfer water from the condensate system to the hotwell so that this type of cooling can be continued indefinitely. Whether or not normal sources of power are available, the operator can manually depressurize the vessel using the electromatic relief valves so that core spray and LPCI will provide adequate core cooling.

6.3.3.1.3.2 Evaluation of HPCI Subsystem Performance (Historical Information)

The HPCI subsystem is designed to provide adequate reactor core cooling for small breaks and to depressurize the reactor primary system to enable cooling water injection by the LPCI and core spray subsystems. A detailed discussion of the performance of the HPCI subsystem in conjunction with the LPCI and core spray subsystems is given in Section 6.3.3.3.

Performance analyses of the HPCI subsystem were conducted in the same manner and with the same basic assumptions as for the core spray subsystem described previously. The detailed model is described in Section 6.3.3.2.2.

The results of a performance analysis in the original FSAR at 2527 MW_t of the HPCI subsystem for a typical small break within the protection range of the unassisted HPCI subsystem are shown in the Figure 6.3-14. During the initial phase of the transient before the HPCI subsystem begins operation, the reactor primary system pressure does not change significantly due to the release of the core stored energy and the action of the main turbine pressure regulator. The small liquid break cannot remove enough energy from the system to cause a rapid pressure decrease. When the HPCI subsystem begins operation, a significant change in the vessel depressurization rate occurs due to the condensation of steam by the cold fluid pumped into the reactor vessel by the HPCI subsystem. The effect of the mass addition by HPCI is also reflected in the changing slope of the liquid inventory trace.

In the original FSAR analysis, the reactor vessel pressure continues to decrease, the HPCI flow momentarily reaches equilibrium with the flow through the break. Continued depressurization causes the break flow to decrease below the HPCI flow and the liquid inventory begins to rise. This type of response is typical of the small breaks. The core never uncovers and is continuously cooled throughout the transient so that no core damage of any kind occurs for breaks that lie within the range of the HPCI.

The HPCI subsystem is designed to deliver full rated flow down to a reactor pressure of 165 psia. For lower pressures, the estimated flow decreases linearly to zero at 65 psia reactor pressure. If reactor pressure drops below the low pressure isolation setpoint, a later pressure buildup above the setpoint would automatically restart the turbine if a HPCI initiation signal were present. Thus, slow pressure changes may occur depending on the level in the core and the fraction of decay heat released to the fluid. If the HPCI subsystem decreases reactor pressure below the low pressure isolation and shuts off while the level is below the top of the core, subsequent level rise would cause enough energy to be added from core heat to raise the pressure which would reactuate the HPCI turbine. However, this discussion is focused on the operation of HPCI acting alone from the original FSAR analysis, a scenario that is not in the design basis. The integrated operation of all ECCS subsystems is discussed in Section 6.3.3.4.

An evaluation was made to evaluate the combined performance of the HPCI and LPCI subsystems, considering a 0.3 square foot break area, a 100 psig low reactor pressure HPCI isolation, and a HPCI restart (with a delay of 30 seconds) after reactor pressure rises above 100 psig. It should be noted that the evaluation was intended to address the performance capabilities of the HPCI and LPCI subsystems under one specific break size in the original FSAR at 2527 MW_t. However, this evaluation was not intended to establish the design basis for either system. Refer to Section 6.3.3.4 for a discussion of integrated system operating sequences, under various design basis accident scenarios.

In the original FSAR analysis at 2527 MW_t during the HPCI restart time the water level inside the shroud is restored and the addition of decay heat causes pressure to seek an equilibrium value so that the energy absorbed by the HPCI flow plus that leaving through the break is equal to decay heat. Spillage of LPCI flow from inside the shroud to outside the shroud is important at this point because the LPCI flow which spills would absorb energy from the primary system flow as it passes through the annulus and the recirculation loop to the break. However, this depressurization effect is conservatively ignored in the analysis. As the LPCI spillage flow passes through the break, it reduces the area available for saturated blowdown thereby tending to hold pressure constant.

In the original FSAR analysis at 2527 $MW_{t,}$ the model used for ECCS evaluations accounted for restart of HPCI, compression of saturated fluid by LPCI water, and ramp down of HPCI flow. The model did not take credit for the effect of depressurization by LPCI.

The automatic depressurization system operates completely independently of HPCI or feedwater and is provided as a backup to the HPCI subsystem. If HPCI and/or feedwater cannot maintain reactor water level the ADS will actuate in accordance with initiation logic described in Section 6.3.2.4.2. Additional HPCI performance analysis information is provided in Section 6.3.3.3.

Calculations performed since the current ECCS were first conceived indicated that ADS combined with HPCI or ADS alone will not impose intolerable stresses on either the pressure vessel or the internals. Allowing the ADS to operate simultaneously with HPCI will not lead to the core thermal behavior or pressure transients more severe than with HPCI alone.

Figures 6.3-15 and 6.3-16 show the peak clad temperature and depressurization rates respectively at 2527 MW_t from the original FSAR analysis for the cases of the ADS operating simultaneously with HPCI.

6.3.3.1.3.2.1 HPCI Subsystem Response to Reactor Vessel Level Swell (Historical Information)

Potential level swell and resultant liquid carryover into the HPCI steam line has been studied extensively at 2527 MW_t. Gross moisture carryover to the HPCI turbine should not occur over the range of breaks of interest for this subsystem. The following is a summary of the results of the more detailed discussions which are included later:

A. For breaks below the water surface, the depressurization rate is much less than that for steam breaks. Because the depressurization rate is relatively slow for liquid breaks, the level swell phenomenon will not occur. Even for the maximum liquid break, the level does not rise above its initial value.

B. For breaks above the water surface, the ECCS bar chart (Figure 6.3-1) shows that the HPCI subsystem is required only for breaks smaller than 0.13 square feet. The minimum break size which could cause a swell condition sufficient to ultimately flood the HPCI steam line is 0.35 to 0.40 square feet. Thus, a steam break large enough to cause sufficient swelling to flood the steam line would depressurize the vessel fast enough such that only LPCI and/or core spray would be required for adequate core cooling.

C. Even if a slug of water were to enter the HPCI steam line, evidence indicates that moisture entrainment and turbulent mixing would occur, and slugging would not occur.

D. If the HPCI turbine were to ingest a slug of water, failure of the casing would not occur and no release of radiation could occur by this mechanism. Some leakage might occur through the gland seal.

The isolation signals which serve to ensure isolation of the HPCI in the event that a water slug damages the turbine (and also fails the gland seal condenser) are generated as follows:

A. The water slug will produce a high differential pressure signal in the steam line which will isolate the HPCI turbine in approximately 50 seconds;

B. In the event of shaft seal steam leakage from the damaged turbine, the high temperature area monitors located in the HPCI turbine room would produce a signal to isolate the HPCI turbine in less than 2 minutes; and

C. Steam flowing through the locked rotor would produce a high exhaust pressure also isolating the HPCI turbine in less than 2 minutes.

As a backup signal to all of the signals mentioned above, the reactor low pressure signal would isolate the HPCI turbine. Based on a main steam line break of sufficient size to produce a water slug in the HPCI line (0.4 square feet), the reactor depressurization rate would produce an isolation signal in less than 15 minutes. The 15-minute time interval for depressurization of the reactor vessel was determined based on a steam line break at 2527 MW_t of 0.4 square feet, no HPCI cooling, no automatic blowdown, and depressurization from 1000 psig to 100 psig. This postulated depressurization cannot possibly occur, because if HPCI were available during this time, depressurization would occur in 8 minutes. If HPCI were not available, automatic blowdown of the reactor vessel would occur, depressurizing the vessel at an even greater rate.

6.3.3.1.3.2.1.1 Model for Level Swell Analysis (Historical Information)

The analysis of moisture carryover to the HPCI turbine was based upon a break size of 0.2 square feet at 2527 MW_t, which is conservative with respect to the expected level rise corresponding to a steam break of 0.13 square feet. The phenomenon was modeled as described below:

Following a primary system break at 2527 MW_t, the level in the separation region outside the core shroud was determined from the volume of mixture in this region at any time. At the start of the transient, the total mixture volume was known from the position of the water level and the separation region geometry (free surface region around separators). This volume was continuously integrated in the model simulation of reactor blowdown so that level could be tracked.

The rate of change of mixture volume at any time was evaluated from the various flows to and from the separation region. These flows were as follows:

A. Separator flow,

B. Flow to the downcomer, and

C. Free separation of steam from the surface.

The ability of the steam separators to perform their function is dependent on level. When tracking the level after a steam break, it was assumed that separator efficiency becomes zero whenever the level reaches the top of the separators. This minimizes the quality of any two-phase blowdown. This is doubly conservative in that the model ignored steam tunneling, which occurs when the level is only slightly above the separators, and that the steam flow from the upper plenum is injected into the entire mixture volume.

Both the total separator flow and the flow to or from the downcomer were calculated from the current pressure differences. Each of these regions was a pressure node in the overall reactor model; internodal flow calculations included momentum effects.

During the transient, the rate at which steam is separated from the surface of the mixture was determined from the current surface area, the surface quality, and the bubble rise velocity. To maximize any level swell and to minimize the quality of any two-phase carryover to the steam line, it was assumed that the mixture was of uniform quality. In fact, the surface quality would be higher than the average and the free separation rate thus greater than the calculated rate.

A bubble rise velocity of 1 ft/s was used. This was conservative because it resulted in a faster and higher level rise than if a faster bubble rise velocity had been used.

6.3.3.1.3.2.1.2 Moisture Carryover to HPCI - Breaks Smaller than 0.13 Square Feet (Historical Information)

The ECCS performance bar chart (Figure 6.3-1) at 2527 MW_t in the original FSAR analysis, shows that for pipe breaks above the water surface, the HPCI subsystem is required only for breaks smaller than 0.13 square feet. However, analysis of moisture carryover to the HPCI turbine was based on the original value of 0.2 square feet which was presented in the "old" core cooling model. Therefore, the following analysis is conservative with respect to the expected level rise corresponding to 0.13 square feet. The level rise transient for a 0.2 square foot break inside the drywell is shown in Figure 6.3-17. The break inside the drywell would result in a more severe transient level response than the break which is outside the drywell because ADS would be initiated by the combined reactor low-low level and high drywell signals maintained for 2 minutes. A break outside the drywell would not result in a high drywell pressure; therefore, ADS would not be initiated until after an 8.5-minute delay, if other conditions are met (refer to Section 6.3.2.4.2). However, the ADS initiation with the 8.5-minute logic is not addressed by this analysis.

The level rise at 2527 MW_t presented in Figures 6.3-17 and 6.3-18 shows that the two-phase mixture level in the dryer annulus (approximately 10 inches above normal water level due to dryer ΔP) is above the bottom of the HPCI line for only 4 seconds during the initial part of the transient. Initiation of ADS after about 2 minutes will not cause the level to reach the HPCI steam line. Therefore, the only period that must be considered with respect to HPCI moisture carryover is the first 2 to 6 seconds, and during this time the HPCI subsystem is not yet operating. The HPCI subsystem is not operating because about 2 seconds is required to receive the high drywell pressure signal and an additional 10 seconds is required until the HPCI control valves start to open and admit steam. Since the HPCI line is closed when mixture level reaches the line, no mixture is drawn into the line by steam flow. However, some mixture will flow into the HPCI line by gravity while the water level is above the pipe line elevation.

The mixture flow at 2527 MW_t, into the steam line when the mixture level exceeds the HPCI line elevation is shown in Figure 6.3-18. The total integrated mass entering the steam line is only 75 pounds of mixture. Initially, this mixture will flow into the line as a stratified steam on the bottom of the pipe since there is no steam flow. Within 30 seconds after the break, the steam velocity will increase to 32 ft/s because the turbine admission valves have opened.

This velocity is sufficiently high that gradual moisture entrainment would be expected, particularly since the HPCI steam line is about 350 feet long and includes vertical sections totaling about 85 feet. The most probable sites of moisture entrainment would occur at each of a series of five vertical sections ranging in length from 8 to 26 feet.

It is considered unlikely that the stratified flow could all be entrained at one vertical section. However, if this were postulated to be the case, the entrainment rate would be only 4 lb/s, even if the stratified fluid was flowing 1-inch deep in the bottom of the line. Therefore, even with complete entrainment of the stratified stream at one vertical section, the resulting two-phase slip flow mixture would have a flowing quality of 0.91. For the expected HPCI line mass velocity, the mixture flow is shown to definitely be in the annular flow regime. The fact that annular flow is established also demonstrates that slugging is not a concern.

It is more likely, however, that total entrainment would occur over at least two or three vertical sections rather than all in one section. In this case the entrainment rate would be considerably reduced and the resulting two-phase mixture quality would be correspondingly increased. Therefore, the mixture quality reaching the HPCI turbine would more likely be 0.96 (4% moisture) or more.

The turbine was specified for operation with dry, saturated steam. The turbine is of a class normally used in extraction steam applications where continuous operation with moisture content as high as 5 to 10% is encountered. For example, although not measured quantitatively, the following experiences are pertinent:

A. Boiler feed turbines of similar design are known to run continuously with moisture content as high as 5 to 10%.

B. The low pressure turbine of the main turbine unit normally runs with moisture content as high as 3 to 15% on a continuous basis.

The HPCI turbine has been designed for high reliability under its design requirements of quick starting. Moreover, the turbine has adequate capacity to accept the small losses in efficiency due to any credible moisture carryover since HPCI turbine efficiency is not of paramount importance.

6.3.3.1.3.2.1.3 Moisture Carryover to HPCI - Breaks Larger than 0.2 Square Feet (Historical Information)

For breaks above the water level larger than 0.2 square feet at 2527 MW_t in the original FSAR analysis, the level rise would be higher and the moisture content at the HPCI turbine would be greater. If it is postulated that the mixture level is above the steam line elevation when the turbine admission valves are open, as might be the case for steam line breaks above 0.2 square feet, it would still not be possible to form solid water slugs in the steam line. Flashing due to the static pressure drop at the inlet and other local losses would tend to increase the mixture quality and provide turbulent mixing. The nature of two-phase mixture blowdown flow was discussed in Reference 4, and it was demonstrated that slugs will not occur.

6.3.3.1.3.2.1.4 Pressure Rise at HPCI Turbine Due to Moisture Carryover (Historical Information)

It has been experimentally demonstrated that the pressure rise caused by sudden deceleration of a two-phase mixture, such as might occur in the HPCI turbine, is not significantly higher than the pressure rise for steam.[5] The pressure rise was measured following closure of a fast-acting valve (typically 50 milliseconds). Since the acoustic transmission time to the vessel and back to the valve was 70 milliseconds, the valve closure was essentially instantaneous. Thus it is concluded that even if a two-phase mixture did enter the HPCI steam line, no significant pressure rise would occur at the turbine since this deceleration would be less severe than the instantaneous deceleration used in the experiment.

Additional experimental data were also provided by the main steam isolation valve test which was reported in Reference 6. The transition flow tests were started with an established steam/water interface. Even so, the measured pressure rise at the valve indicates that the interface had dispersed by the time it reached the valve. Furthermore, the experimentally measured pressure rise was only about one-third of the analytically calculated value which was based on a discrete steam/mixture interface. It is concluded that even if a water slug did enter the HPCI steam line, it would disperse before reaching the HPCI turbine.

6.3.3.1.3.2.1.5 Evaluation of Effects of Gross Carryover on the HPCI Turbine (Historical Information)

For postulated break sizes where water swell could occur, it is difficult if not impossible to predict whether the HPCI turbine is capable of continued operation while ingesting slugs of water. Based on historic information of similar turbine applications (on naval quick start units), the most detrimental effect of a water slug accident would be thrust bearing failure, resulting in axial interference between rotating and stationary parts. This worst condition would not result in casing failure or any material leaving the turbine casing.[7] Since failure of the turbine casing is not possible, no calculation of radiation release has been made for this hypothetical situation. Gland seal leakage might be possible however.

With the gland seal condenser equipment functioning, a slight vacuum (14.5 psia) is maintained at the turbine shaft seals, and there is no leakage external to the turbine casing. Assuming ultimate failure of the gland seal condenser (with a locked turbine rotor, there will be no cooling water flow to the condenser), it would be possible to have turbine shaft seal leakage external to the machine, assuming the steam supply valves to the turbine remain open. The seal leakage would be 0.6 lb/s or less.

Calculation of radiation release for shaft seal leakage was based on the following source terms:

A. Total coolant activity of 2.4 μCi/cc;

B. A release to the secondary containment of 550 pounds of steam which was assumed to have associated with it the total activity consistent with 550 pounds of liquid;

C. Release of activity to the environment via the standby gas treatment system (filter efficiency for iodine of 99%) and the 310-foot chimney; and

D. In addition to the activity associated with the vaporized liquid, 0.01 curies of noble gas activity are also released to the environment.

Assuming the steam line low pressure signal successfully isolates the turbine loop, a maximum period of 15 minutes will have elapsed, with a maximum external leakage quantity of less than 550 pounds of steam. This total leakage would result in the following released radiation doses using TID-14844 Source Term:

A. Cloud gamma dose of 3.9×10^{-8} rem, compared with an allowable limit of 25 rem, per 10 CFR 100, and

B. Thyroid inhalation dose of 8.7×10^{-6} rem, compared with an allowable limit of 300 rem, per 10 CFR 100.

It is concluded that even with the most pessimistic combinations of water slug damage (i.e., locked turbine rotor, failed gland seal condenser, and steam isolation not occurring until 15 minutes after scram), the radiation dose rates from external shaft seal leakage are significantly less than the allowable quantities as given in 10 CFR 100. Since these doses were insignificant, the values were not converted to TEDE using Alternative Source Term.

6.3.3.1.3.2.1.6 Evaluation of HPCI Operation with Fuel Damage (Historical Information)

Radiation monitors are not required on the HPCI turbine gland seal discharge line. The only time the discharge from the HPCI turbine gland seals will be of special concern will be during an accident which involves the perforation of fuel rods. Since rupture of a main steam line will not result in any fuel rod perforations, this type of accident is of no special interest as far as gaseous discharge from the HPCI turbine gland seal condenser is concerned.

The spectrum of break sizes which could result in fuel damage and, hence, transport of activity to the gland seal condenser, have been investigated as a function of location, total rod perforations, and HPCI turbine run time. The results of this investigation have shown that a 0.3 square foot liquid break is the break size of major interest and would result in the perforation of 3.5% of the total fuel rods. For rupture sizes less than 0.3 square feet, no fuel damage occurs. For larger rupture sizes, while the number of perforations may be greater than for a 0.3 square foot break, the actual run time of the HPCI turbine is less, resulting therein in a smaller amount of activity being transferred to the turbine gland seal condenser.

The analysis considers a 0.3 square foot break, perforations of 3.5% of the fuel rods, a HPCI turbine run time of 3 hours, associated flow to the HPCI turbine gland seals and gland seal condenser, and the release rate from the gland seal condenser to the standby gas treatment system and then to the stack. The total amount of activity calculated to be released to the environment would be 6.3×10^{-2} curies of iodine and 3.0×10^{2} curies of noble gases. The release of this activity would result in a thyroid dose of 3×10^{-4} rem and a cloud gamma dose of 3.0×10^{-5} rem as calculated using TID-14844 Source Term. Total Effective Dose Equivalent (TEDE) doses were also calculated using Alternative Source Term methods in Chapter 15.

6.3.3.1.3.3 Summary of HPCI Subsystem Performance (Historical Information)

Based upon performance analysis of equipment provided, it is concluded that the HPCI subsystem will maintain water inventory sufficient to ensure core cooling for small breaks. For larger breaks it will increase vessel depressurization and help maintain liquid inventory. This depressurization will enable the core spray subsystem and/or the LPCI subsystem to provide adequate core cooling.

6.3.3.1.4 Automatic Depressurization Subsystem

The automatic depressurization subsystem is designed to depressurize the reactor to permit the LPCI and core spray subsystems to cool the reactor core during a small break loss-of-coolant accident; this size break would result in a loss of coolant without a significant pressure reduction, so neither low pressure system could provide adequate core cooling without ADS. The performance analysis of the ADS is conducted in the same manner and with the same basic assumptions as the core spray subsystem analysis discussed in Section 6.3.3.1.1. When the ADS is actuated, the critical flow of steam through the relief valves results in a maximum energy removal rate with a corresponding minimum mass loss. Thus, the specific internal energy of the saturated fluid in the system is rapidly decreased, which causes a pressure reduction. Some steam cooling would occur during the blowdown phase. Moreover, since the ADS does not provide coolant makeup to the reactor, the ADS is considered only in conjunction with the core spray or LPCI subsystems as a backup to the HPCI.

The Westinghouse LOCA analysis for SVEA-96 Optima2 fuel also requires a MAPLHGR reduction with one ADS out-of-service (Reference 78). All of the ADS valves are assumed to operate to reduce vessel pressure during events that do not have HPCI available.

To ensure peak clad temperatures do not exceed 2200°F as specified by 10 CFR 50.46, core thermal limits will be adjusted as necessary. Refer to Section 4.2 for a description of the core thermal limits.

Design evaluation of the ADS is included in the core spray and LPCI performance analysis discussions in Sections 6.3.3.1.1, 6.3.3.1.2, 6.3.3.1.3.2, and 6.3.3.3 on intermediate and small breaks.

6.3.3.1.4.1 Automatic Depressurization Subsystem Response to a Loss of Offsite Power at 2527 MWt (Historical Information)

A loss of offsite power to both Dresden units at 2527 MW_t, concurrent with a DBA LOCA on one unit and a single failure (including failure of the unit diesel) on the non-accident unit, has been evaluated. If this combination of events were to occur, shutdown of the non-accident unit would commence with the isolation condenser and HPCI. Once reflood has occurred on the accident unit, the operators would be able to continue long term mitigation of the accident using that unit's diesel and would manually transfer the Unit 2/3 (swing) diesel to the non-accident unit to support cooldown of the non-accident unit. Station procedures detail actions required in the event of a complete loss of ac power.

Since automatic blowdown of the non-accident unit is undesirable, the response of ADS to the loss of ac power has been evaluated at 2527 MW_t to ensure reactor water level will recover and clear the reactor low level permissive prior to the ADS 120 second time delay timeout. This evaluation at 2527 MW_t did not take credit for the low pressure ECCS pump discharge pressure interlock which is required for ADS initiation.

The evaluation at 2527 MW_t assumed a loss of offsite power to both units simultaneously with a DBA on one unit. Consideration was given to all possible single failures, including the following:

A. Failure of the high pressure coolant injection system,

B. Failure of the isolation condenser,

C. Failure of the non-accident unit single available emergency diesel-generator (the other two diesel-generators were assumed to be unavailable due to a design basis accident on the other unit).

Analyses at 2527 MW_t have shown that the most severe case (failure of the emergency diesel-generator) will not cause automatic actuation of ADS on the non-accident unit.

6.3.3.1.4.2 GE LOCA Analysis at 2957 MWt

The GE LOCA analysis at 2957 MWt (Reference 70) for GE14, 9x9-2, and ATRIUM-9B fuel types assumes all of ADS valves operate to reduce vessel pressure during the events that do not have HPCI available. With implementation of GE LOCA analysis in Reference 70, operation at 2957 MWt with one ADS out-of-service has LHGR and MAPLHGR reduction requirements for any reload.

6.3.3.1.4.3 Westinghouse LOCA Analysis

The Westinghouse LOCA analysis at 2957 MWt (Reference 78) for SVEA-96 Optima2 fuel assumes all of ADS valves operate to reduce vessel pressure during the events that do not have HPCI available. Operation with one ADS valve out-of-service has MAPLHGR reduction requirements.

6.3.3.2 Integrated Emergency Core Cooling System Performance Evaluation

6.3.3.2.1 Analytical Methods and Models for LOCA Analysis

6.3.3.2.1.1 Description of GE LOCA Analysis at 2957 MWt

The SAFER/GESTR-LOCA method as described in Reference 70 was used for Dresden and Quad Cities LOCA analysis based on Reference 71 bounding input parameters for both plants. The analysis was performed for GE14, 9x9-2, and ATRIUM-9B assuming a thermal power level of 2957 MWt corresponding to 100% of license power uprate. A schematic of the model used is provided in Figure 6.3-19b.

6.3.3.2.1.2 Westinghouse LOCA Analysis

The Westinghouse LOCA method as described in Reference 78 was used for Dresden Units 2 & 3 LOCA analysis based on bounding input parameters for both plants. The Dresden analysis inputs are identical for Dresden Units 2 and 3 with the exception of the LPCS delivered flows and shroud leakages.

The Westinghouse BWR LOCA methodology is described in References 80 through 87. The methodology used in support of the Dresden and Quad Cities units is the USA5 evaluation model (EM), which is described in Reference 85. This methodology makes use of the GOBLIN series of computer codes to calculate the BWR transient response to both large and small break LOCAs.

Page 6.3-37 deleted intentionally.

Page 6.3-38 deleted intentionally.

Page 6.3-39 deleted intentionally.

6.3.3.2.2 Historical Analysis Model of the Emergency Core Cooling System at 2527 MWt

The original performance analyses of the emergency core cooling system were based on an analytical prediction of the pressure and liquid levels in the pressure vessel at any time after a break. The analytical model assumed a spatially uniform pressure in the reactor pressure vessel and saturated fluid conditions. The thermodynamic state of the fluid in the reactor vessel at any time was determined by the simultaneous solution of conservation of mass, energy, and volume equations. The flow through the postulated break may be subcooled water, saturated water, and/or saturated steam, depending on the conditions at the break during the transient.

The single node model previously used for performance evaluations was replaced by a two node model which allows subcooled or saturated water to spill from either node to the other via the jet pumps. The spillage is allowed to occur with no resistance between the two nodes, consistent with the assumption of a uniform spatial pressure. The amount of spillage during a time step and the type of fluid transferred is determined at the end of each time step such that equal elevation heads exist inside the jet pumps and outside the shroud. Saturated water is allowed to spill from inside the shroud to outside the shroud if the level of the subcooled water is below the bottom of the jet pumps and if the elevation head inside the jet pumps is greater than that outside. If the level of the subcooled water is above the bottom of the jet pumps, then any spillage which occurs will be the accumulated subcooled LPCI water. Similarly, saturated water will spill from the region outside the shroud to the region inside if the elevation head of the water outside the shroud is greater than that inside the jet pumps. If the accumulated unmixed HPCI flow is above the top of the jet pumps outside the shroud, then the accumulated unmixed HPCI flow will spill inside the shroud and be added to the accumulated subcooled LPCI water.

The assumption of uniform spatial pressure used in the model described is justified particularly for the small breaks after recirculation pump coastdown (about 16 to 25 seconds) because there are no significant driving forces to cause pressure differentials to exist. For example, after the recirculation pumps coast down, the pressure drop from midcore to the steam dome is calculated to be approximately 0.001 psi at a reactor pressure of 900 psia or about 0.003 psi at a reactor pressure of 100 psia, due to the natural circulation which exists with the water levels inside and outside the shroud at the top of the core. When core spray is actuated, local pressure reduction in the steam plenum above the core could exist. If all the steam required to raise the temperature of the core spray water to saturation were to pass from the steam dome through the separators to the core spray flow, the local pressure reduction would amount to about 0.002 psi when core spray is at rated flow. This has also been verified through the comparison of multi-node blowdown calculations with single node blowdown calculations.

As shown in Figure 6.3-20, peak clad temperatures will be less than clad melt if the HPCI mixing efficiency is at least 30% for the LPCI case. Even lower efficiencies would be required for the core spray case because of the depressurization effect of core spray. As shown in Figure 6.3-21, the peak clad temperatures predicted across the break spectrum are considerably less than clad melt temperatures. As shown in Table 6.3-1 the delivery pressure of LPCI is about 275 psid and that of core spray is about 260 psid. The LPCI subsystem will deliver 10,200 gal/min at a differential pressure between the suppression pool and the reactor pressure vessel of 150 psid; whereas, the core spray will deliver about 3825 gal/min at the same differential pressure. Since the HPCI system will deliver rated flow down to a reactor pressure of 150 psig and estimated performance indicates that the HPCI flow will decrease linearly from rated at 150 psig down to zero at 50 psig, (HPCI auto-isolation occurs as defined in sections 6.3.2.3.3, 7.31 and 7.32), a substantial overlap in flow capacity between the HPCI and the low pressure subsystems exist. From the above discussion and performance results it is apparent that adequate margin exists between the shutoff head of the low pressure subsystems and the cutoff pressure of HPCI flow.

A complete discussion and explanation of the experimental program to verify the HPCI system mixing efficiency is contained in Reference 33.

The described ECCS analysis model differs from the model previously used for emergency core cooling system analysis in the following ways:

A. The distributed axial power shape is considered for evaluation of the decay heat released to the fluid rather than the "core one-half covered" model;

B. The system is divided into two nodes for liquid level calculation purposes, one inside the shroud and one outside the shroud;

C. Break flow quality is based on the water level in the region outside the shroud and the break location, i.e., the break flow quality is not assumed constant but rather is determined by consideration of the quality of the fluid which exists at the break; and

D. Level swell is accounted for in the two regions, rather than the previous practice of uniform level across the vessel based on collapsed liquid inventory.

In a saturated system the thermodynamic state can be completely defined by:

Average specific internal energy,

$$\bar{e} = \frac{E}{M}, \text{ and} \qquad (1)$$

Average specific volume,

$$v = \frac{V}{M}, \qquad (2)$$

where:

E = total energy in fluid

M = total mass of fluid

V = total volume of fluid

The average specific internal energy and volume can also be defined in terms of quality:

$$\bar{e} = e_f + X e_{fg} \tag{3}$$

$$v = v_f + X v_{fg} \tag{4}$$

where:

$$X = \text{quality} = \frac{\text{mass of steam}}{\text{total mass in pressure vessel}}$$

e = specific energy

v = specific volume

Subscript f refers to saturated liquid and subscript fg refers to change by evaporation.

Solving Equations 3 and 4 for X, setting them equal to each other, and substituting from Equations 1 and 2:

$$\frac{V}{M} = v_f + \frac{\left(\frac{E}{M} - e_f\right) v_{fg}}{e_{fg}} \tag{5}$$

Equation 5 is satisfied at a particular pressure which defines system pressure P. The saturated liquid inventory can then be determined by:

$$V_L = M\left[1 - \frac{(\bar{v} - v_f)\, V_f}{v_{fg}}\right] \tag{6}$$

where:

V_L = volume of saturated liquid

Figure 6.3-22 is a schematic representation of the quantities entering and leaving the reactor vessel.

The mass balance on the saturated fluid is:

$$\dot{M} = W_{CS} + FMX\, W_{HPI} - W_S - W_{AR} - W_B - W_{HPO} + W_{sat} \tag{7}$$

where:

W_{CS} = core spray flowrate

W_{HPI} = HPCI flowrate into vessel

W_{HPO} = steam flowrate to HPCI turbine

W_S = main steam flowrate

W_{AR} = auto relief flowrate

W_B = break flowrate

W_{sat} = rate of saturation of subcooled water

FMX = efficiency factor of HPCI flow

The energy balance is:

$$\dot{E} = \dot{Q}_{DH} + W_{CS} h_{CS} + FMX \; W_{HPI} h_{HPI} - (W_S + W_{AR} + W_{HPO}) h_g - W_B h_B + W_{sat} h_f + \dot{Q}_{SH} \quad (8)$$

where:

$\dot{Q}_{DH}$ = decay heat energy addition rate

$\dot{Q}_{SH}$ = stored heat energy addition rate

h_{CS} = enthalpy of core spray flow

h_{HPI} = enthalpy of HPCI inlet flow

h_f = enthalpy of saturated liquid

h_g = enthalpy of saturated steam

h_B = enthalpy of break flow

The saturated volume balance is:

$$V = -Q_{LPCI} - Q_{HPI} + W_{sat} v_{sub} + W_{sub} v_{sub} \quad (9)$$

where:

Q_{LPCI} = LPCI volume flowrate

Q_{HPI} = $(1 - FMX)\, v_{HPI}$

W_{sub} = subcooled flowrate from break

v_{sub} = specific volume of subcooled mass

The isolation condenser is not considered in the calculations. This results in a more conservative calculation of core temperatures and liquid levels. Further conservatism is added to the calculations by allowing LPCI flow to accumulate in the bottom of the pressure vessel without absorbing any energy from the saturated fluid. Thus, LPCI flow is assumed to remain subcooled and does not appear in the mass and energy conservation equations. The only effect of LPCI flow is to reduce the volume of the saturated system in accordance with the volume balance, Equation 9. In the model the subcooled LPCI water can only become saturated by heat addition in the core.

Integration of Equations 7, 8, and 9 defines the properties E, M, and V, which are required to determine the liquid inventory in the vessel. The solution of these equations describes the reactor vessel pressure, coolant inventory, and ECCS performance for the selected break size.

The various flows in Equations 7, 8, and 9 are defined either as input variables or as functions of the state of the fluid in the reactor vessel or both. The logic in the computer program causes flow from the ECCS to be delayed by the amount of time necessary to accomplish standby power startup, valve motions, etc., for a given system assuming the signal to start is a low reactor water level signal. When the time delay has been satisfied the flowrate is determined from an input table which contains flow as a function of vessel pressure.

The HPCI flow is modified by a multiplier to account for the effect of imperfect mixing of the HPCI inlet flow. The multiplier is in the form of a fraction (FMX). The magnitude of FMX is a function of reactor pressure (saturation temperature), the water level in the vessel, the temperature of the HPCI water, and the HPCI flowrate. Calculations to determine the mixing efficiency are performed in the same manner and with the same assumptions as discussed in Reference 34. These techniques indicate that the mixing efficiency will vary from an initial value of about 80% early in the transient to about 95% as water level and pressure drop. The exact value of mixing efficiency is not a very important variable, as can be seen from Figure 6.3-20. The maximum mixing efficiency (treated as a constant) required to maintain clad temperatures below melting is less than 30%.

The modified flow from HPCI mixes with the saturated fluid in the reactor vessel. The remaining portion of HPCI flow is considered unmixed and to remain subcooled without absorbing any energy from the saturated system. If the level of the unmixed volume of subcooled liquid reaches the elevation of the break, it will begin flowing out through the break at a flowrate defined by Bernoulli's equation.

Main steam line flow is modeled in accordance with the action of the turbine pressure regulator as shown in Figure 6.3-23.

The flow out the break, W_B, is determined in accordance with Moody's critical flow model.[35] The flow will be liquid if only saturated liquid covers the break, steam if the liquid level is below the break, or combination of liquid and steam if the water level is at the elevation of the break. No frictional effects are considered in the determination of the rate of flow out the break.

Core decay heat ($\dot{Q}_{DH}$) and stored heat ($\dot{Q}_{SH}$) are input functions of time. The fraction of decay heat released to the fluid is dependent on water level in the core and the action of the core spray subsystem. The amount of decay heat transferred to the fluid below the water level can consist of two parts. The first is the heat going into the subcooled fluid. This fraction (called F_{sub}) is determined by integrating the axial power shape from the bottom of the core to the level of the subcooled fluid. The second fraction (called F_{sat}) is the heat going into the saturated water which is determined by integrating the axial power shape between the level of the subcooled fluid and the top of the saturated water level.

If core spray reaches rated flow, all the decay heat is transferred to the core spray fluid. The fraction of decay heat transferred to the core spray for less than rated flow is shown in Figure 6.3-24.

To limit the total fraction of core decay heat entering the fluid to a maximum of 1.0, the fractions are combined by:

$$F = F_{sat} + (1 - F_{sat} - F_{sub}) F_{CS} \tag{10}$$

The $\dot{Q}_{IDH}$ 12 term is then given by:

$$\dot{Q}_{IDH} = (q/q_o) Q_o F \tag{11}$$

where:

q/q_o = decay power generation fraction

Q_o = power level at beginning of transient

F = fraction of total core heat transferred to saturated fluid

The rate of saturation of subcooled water is given by:

$$W_{sat} = \frac{F_{sub} (q/q_o) Q_o}{h_f - h_{sub}} \tag{12}$$

where:

h_{sub} = enthalpy of the subcooled water

Water levels are determined for the regions inside and outside the shroud through the use of Moody's level swell model.[36] The two regions in the vessel are coupled by a static head balance so that the elevation heads inside and outside the shroud are maintained equal unless both levels are below the top of the jet pumps.

The water levels and regions are shown in Figure 6.3-25. Note that the swollen level inside the shroud can be higher than the top of the jet pumps because of the difference in void fraction in the core compared to that in the jet pumps.

Modifications have been made to the model to include the effect of the level at which core heat is added to the fluid. The level at which heat is added affects the swollen level since bubbles generated near the surface of the level will escape rapidly; whereas, those generated at the bottom of the vessel would be present in the liquid for a longer time thereby causing a maximum level swell.

From Equation 6 in Reference 37, the bubble rise velocity relative to the vessel is:

$$V_B(y,t) = \frac{\partial Z}{\partial t} \tag{13}$$

where Z is elevation of a bubble plane in the mixture.

For a vertical vessel with uniform cross sectional area A_v,

$$Z = \frac{1}{A_v}\left[v_f(t)\,M_f(Z) + v_g(t)\,M_g(Z)\right] \tag{14}$$

where $M_f(Z)$ and $M_g(Z)$ are, respectively, masses of liquid and vapor below elevation Z at any time. With a net vaporization rate, W, assumed uniform throughout the mixture, mass balances on the liquid and vapor in the mixture yield:

$$\frac{\partial M_f(Z)}{\partial t} + \frac{M_f(Z)}{M_f(t)}\,W - W_{fr} = 0 \tag{15}$$

$$\frac{\partial M_g(Z)}{\partial t} + \frac{M_f(Z)}{M_f(t)}\,W = 0 \tag{16}$$

where W_{fr} is liquid flowrate downward relative to a rising bubble flow:

$$W_{fr} = \frac{U\,A_v}{v_f}, \tag{17}$$

and U is the bubble rise velocity due to buoyancy.

If dP/dt is sufficiently slow that v_f and v_g do not change significantly during a bubble sweep time T, then Equations 13 through 17 lead to:

$$V_B = \frac{1}{A_v}\left[\frac{M_f(Z)}{M_f(t)}\,v_{fg}\,W + v_f\,W_{fr}\right] \tag{18}$$

since by definition:

$$M_f(Z)\big|_{t=\tau} = M_f(y,\tau), \tag{19}$$

The solution for M_f in Equation 16 for small changes in $M_f(t)$ and W during a bubble sweep time is:

$$M_f(Z) = \frac{W_{fr}}{W}M_f(t) - \left[\frac{W_{fr}}{W}M_f(t) - M_f(y,\tau)\right]e^{-\frac{W}{M_f(t)}(t-\tau)} \tag{20}$$

Equations 18 and 20 lead to the following expression for bubble rise velocity relative to the vessel:

$$V_B = \frac{1}{A_v}\left\{v_g\,w_{fr} - v_{fg}\left[W_{fr} - \frac{M_f(y,\tau)}{M_f(t)}W\right]e^{-\frac{W}{M_f(t)}(t-\tau)}\right\} \tag{21}$$

If W = 0 causing the swelling effect to be absent, Equation 21 reduces to

$$V_B = U \tag{22}$$

which is bubble rise velocity due to buoyancy only.

The bubble sweep time, T, is approximately

$$T = t - \tau \approx \frac{M_f}{W_{fr}} \qquad (23)$$

The distance traveled by a bubble from time τ when the bubble leaves elevation y = 0 until time t when it breaks through the mixture surface is:

$$y = \int_{\tau}^{t} V_B \, dt = \int_{o}^{T} V_B \, d(t - \tau) \qquad (24)$$

The choice of y = 0 at t = τ leads to the initial condition

$$M_f (y, \tau)_{y=0} = 0 \qquad (25)$$

in Equation 21. Substituting for V_B from Equation 21 into Equation 24 and expressing T from Equation 23 leads to

$$y = \frac{M_f(t)}{A_v}\left[v_g - v_{fg}\frac{W_{fr}}{W}\left(1 - e^{-\frac{W}{W_{fr}}}\right)\right] \qquad (26)$$

Since

$$e^{-W/W_{fr}} = 1 - W/W_{fr} + \frac{1}{2}\left(\frac{W}{W_{fr}}\right)^2 + \ldots \qquad (27)$$

Equation 26 can be written as:

$$y_L \approx \frac{M_f \, v_g}{A_v}\left(1 + 0.5\frac{W \, v_{fg}}{U \, A_v}\right) \qquad (28)$$

Since core heat is not added uniformly, a modification to Equation 28 is required. It can be shown that the flashing rate below the mixture level W is given by:

$$W = \frac{\dot{q}}{h_{fg}} - \left[M_f F_1(P) + M_g F_2(P)\right]\frac{dP}{dt} \qquad (29)$$

where:

$$F_1(P) = \frac{1}{h_{rg}}\left(\frac{dh_r}{dP} - v_r\right)$$

$$F_s(P) = \frac{1}{h_{rg}}\left(\frac{dh_g}{dP} - v_g\right)$$

Thus mixture level is given by:

$$y_L = \frac{M_f\, v_f}{A_v}\left\{1 + 0.5\,\frac{v_{fg}}{U\,A_v}\left[\frac{q}{h_{fg}} - M_f\, F_1(P)\,\frac{dP}{dt} + M_g\, F_2(P)\,\frac{dP}{dt}\right]\right\} \tag{30}$$

Equation 30 consists of three basic terms, i.e.:

$$y_L = y_{L_C} + \Delta\, y_{L_P} + \Delta\, y_{L_H} \tag{31}$$

These terms are the collapsed level:

$$y_{L_C} = \frac{M_f\, v_f}{A_v} \tag{32}$$

The increase in level due to depressurization:

$$\Delta\, y_{L_p} = \frac{M_f\, v_f}{A_v}\left\{0.5\,\frac{v_{fg}}{UA_v}\left[-M_f\, F_1(p)\,\frac{dP}{dt} + M_g\, F_2(p)\,\frac{dP}{dt}\right]\right\} \tag{33}$$

and the increase in level due to the uniform addition of heat:

$$\Delta\, y_{L_H} = \frac{M_f\, v_f}{A_v}\left(0.5\,\frac{v_{fg}}{UA_v}\right)\frac{\dot{q}}{h_{fg}} \tag{34}$$

If heat is added non-uniformly, the total liquid mass, M_f, is not affected by the heat but is rather just a part of the mass, say M_{fl}.

Thus the increase in level due to non-uniform heat addition may be written as:

$$\Delta\, y_{L_H} = \frac{M_{fl}}{M_f}\,\Delta\, y_{L_H} \tag{35}$$

In this case M_{fl} is the saturated liquid mass above the bottom of the active core region, $q = F_{sat}\,(q/q_0)\,Q_0$, and M_f is the total saturated liquid mass inside the shroud.

Thus the level is obtained from Equations 31, 32, 33, and 35.

$$y_L = y_{L_C} + \Delta y_{L_P} + \Delta y_{L_H} \qquad (36)$$

$$y_L = \frac{M_f v_f}{A}\left[1 + 0.5\frac{v_{fg}}{UA}\left\{\frac{M_{fl}}{M_f}\left[F_{sat}(q/q_o)\frac{Q_o}{h_{fg}}\right] - M_f F_1(p)\frac{dP}{dt} + M_g F_2(p)\frac{dP}{dt}\right\}\right] \qquad (37)$$

The bubble rise velocity used in this analysis is obtained from experimental data taken with a variety of fluids and corrected to fit the pressure and geometric conditions in the reactor. Zuber and Hench[37]used 0.83 ft/s in their correlation, which showed excellent agreement between analysis and experimental air-water data. Haberman and Morton[38]present bubble rise velocity from several different sources, from different countries. These data indicate that for a bubble diameter of 1 inch, the bubble rise velocity is slightly less than 1 ft/s and for smaller bubbles, the bubble rise velocity is less. The expected bubble size should be of the order of magnitude of the space between fuel rods, about ½ inch. At ½ inch, the bubble rise velocity is 0.8 ft/s. Hence, a bubble rise velocity of 1 ft/s was used as the basis for evaluating the level swell in this analysis.

6.3.3.2.3 Historical Analysis of Recirculation Flow Coastdown During Blowdown at 2527 MWt

It has been determined that during recirculation pump coastdown immediately following a line rupture, all flow from the unaffected recirculation loop goes through the core and that there is a 50%-50% flow split between the core and the jet pumps during the period of flashing in the lower plenum. Flow will not bypass the core through the jet pumps of the broken loop. Flow reversal will not occur in the broken side jet pumps. Thus, all the flow injected into the bottom plenum must go through the core. This flow split is based upon the predictions of a computerized model of the entire reactor recirculation system. The model includes a momentum exchange simulation of the jet pumps that can analyze their performance under all operating conditions. Figure 6.3-26 represents the model used in the analysis of transient jet pump performance. Momentum exchange between the drive and suction flows is assumed to occur in a mixing region in the jet pump throat. The suction and drive flows enter the mixing region with different velocities but at a common static pressure ($P_d = P_s$). At the exit of the mixing length, a homogeneous velocity is established and momentum exchange between the two flows results in an increased static pressure.

The conservation of momentum law states that the rate of change of momentum of a body is equal to the summation of all the forces acting on the body[39] and the summation of forces equals the change in momentum as given by:

$$\begin{aligned}\sum \text{Forces} &= \frac{d}{dt}(MV) \\ &= \frac{\partial}{\partial t}(w\ \ V) + \int Vdw_{out} - \int Vdw_{in}\end{aligned} \qquad (38)$$

For this application, the above equation can be solved in terms of the change of fluid momentum from inlet to exit of the mixing region.

For the linear loss-less mixing region, the only forces acting on the fluid are the static pressure at the inlet and outlet sections. Elevation terms have been neglected; this implies that the momentum exchange occurs over a short distance. Hence,

$$\sum Fdt = (P_s A_s + P_d A_d - P_t A_t)\, dt \qquad (39)$$

Combining the equations yields:

$$P_t = \left(P_s A_s + P_d A_d + \frac{W_d^2}{\rho_d A_d g} + \frac{w_s^2}{\rho_s A_s g} - \frac{W_t^2}{\rho_t A_t g} \right) \bullet \frac{1}{A_t} \qquad (40)$$

Thus the total pressure rise between the downcomer region of the reactor and the entrance to the diffuser section of the jet pumps is given by:

$$P_t + \frac{W_t^2}{2g\rho_t A_t^2} - \left(P_s + \frac{W_s^2}{2g\rho_s A_s^2} + CW_s^2 \right) \qquad (41)$$

where C is the friction coefficient for flow in the jet pump suction.

This model is used to analyze the transient performance of the jet pumps under all possible modes of operation.

Following the failure of a main recirculation line, the flow in the 10 drive nozzles in the broken loop will very rapidly reverse and critical flow will become established at the nozzles.

The fluid leaving the vessel annulus through the jet nozzles at high velocity imparts significant forward momentum to the fluid in the jet pumps. When analyzing this mode of operation with the above model, it is calculated that during the early part of the transient there would actually be a positive total flow induced through the jet pumps of the broken loop. However, this positive forward flow is neglected in the analyses and it is merely assumed that no reverse flow occurs through the jet pumps of the broken loop while the suction inlets of the jet pumps are covered with water. Induced positive pressure to prevent flow reversal in the jet pumps of the broken line can be demonstrated by a numerical example. Substituting the physical constants and solving Equation 40 reveals a positive jet pump shutoff head (i.e., pressure with zero diffuser flow) in excess of about 20 psi. The pressure difference between the lower plenum and the downcomer drops to less than 10 psi during blowdown. (See Section 6.3.3.2.5). Since the induced equivalent shutoff head of the jet pump is well in excess of this amount, it is clear that plenum flow will be prevented from bypassing the core through the broken loop jet pumps. Thus all the flow from the unbroken loop must go through the core until such time that the top of the jet pumps are uncovered.

When the mixture in the downcomer region of the reactor is completely discharged through the broken recirculation line, the depressurization rate in the vessel will increase markedly since steam rather than liquid will be leaving through the break. This will produce vigorous flashing of the lower vessel plenum inventory, resulting in high flowrates into the core and backwards through both sets of jet pump diffusers. The split of the flow leaving the lower plenum depends upon the resistances of three flow paths, i.e., through the unbroken side jet pumps, through the core, and through the broken side jet pumps. The reverse flow resistances of the two sets of jet pumps are calculated using the models shown in Figure 6.3-27.

Since it is conservative for the reverse flow in the jet pumps to have a low resistance, the minimum expected loss coefficients are used.

If the area of the jet pump throat is A_t and the specific volume of the flow leaving the lower plenum is v, the total pressure loss between 1 and 4 is:

$$\frac{K_{1\text{-}4}\, W_{j1}^2\, v}{2\,g\;A_t^2} + \frac{Z}{v} \qquad (42)$$

for the unbroken recirculation loop, and

$$\frac{K_{1\text{-}3}\ \left(W_{j2}+W_B\right)^2 v}{2\,g\,A_t^2}+\frac{K_{3\text{-}4}\ W_{j2}^2\,v}{2\,g\,A_t^2}+\frac{Z}{v} \qquad (43)$$

for the broken recirculation loop.

W_B is calculated by assuming critical flow at the minimum nozzle area and applying the Moody blowdown model.[40]

For flow through the core, the total pressure loss between core inlet and outlet is given by an expression of the form:

$$K_c \bullet\ W_c^2 + \frac{Z_c}{v} \qquad (44)$$

where W_c is the total core flow, Z_c is the vertical length of the flow path, K_c is a loss coefficient and v is the flow-specific volume.

For flow into and through the steam separators, the total pressure drop is given by:

$$K_s\,W_c^2\ v + \frac{Z_s}{v} \qquad (45)$$

where Z_s is the distance between the core outlet and the separator outlet.

The flow split between the three available flow paths is calculated by equating the total pressure losses in each of the paths and solving the three equations. For example, when the lower plenum begins to flash the total flow is about 50,000 lb/s.

Substituting 0.36 square feet for the area of each jet pump throat, the elevation terms, the specific volume, and loss factors of 0.75 x 10^{-6} $s^2/in.^2\text{-}ft^3$ and 0.15 x 10^{-6} $s^2/in.^2\text{-}ft^3$, the separator loss coefficients respectively, it is found upon solving the above equations that 28,000 lb/s will go through the core and 22,000 lb/s will go backwards through the 20 jet pumps.

The peak clad temperatures are not extremely sensitive to reduced flow split later in the transient. A reduced flow split would result in a shorter period of high heat transfer rates and an earlier start of core heatup. If the split were about 10 percentage points less, the core would begin to blanket 1 second sooner, which would result in only a 50°F increase in peak temperature.

6.3.3.2.4 Historical Analysis of Dryout Cooling at 2527 MWt

Dryout cooling is a term used to summarize the observation that, when flow is instantly stagnated from its rated value, a fuel rod will be highly cooled by nucleate boiling for only a few seconds followed by a rapidly degenerating heat transfer. These heat transfer test results were obtained in 1965 for non-jet pump plants and reported in detail in APED-5458.[2] These tests were intended to simulate as closely as possible the conditions to be expected in the non-jet pump BWR, which experiences very rapid core flow stoppage following a design recirculation line break. The test rig used to evaluate heat transfer during vessel blowdown caused by a postulated LOCA was based on the design configuration for the non-jet pump BWR. For the postulated recirculation line break, the depressurization of the lower core plenum would cause essentially an instantaneous core flow stoppage. Furthermore, the response time in the unaffected recirculation lines is so slow that the recirculation pumps could not provide sufficient flow into the core inlet plenum to make up for the loss through the break. In the test rig, the system pump was isolated, thereby completely eliminating additional flow to the core inlet plenum. Therefore, the measured dryout heat transfer coefficients would apply only to the non-jet pump plant since they simulated sudden flow stoppage.

Basically flow reversals or flow stagnations do not occur in a jet pump plant because blowdown cannot occur directly out of the bottom plenum. Only when the jet pumps are uncovered or when the recirculation pumps cavitate (thus reducing the driving flow) can flow leave the bottom plenum via the jet pumps without going through the core. Calculations using the reactor transient flow model show that during blowdown the pressure in the bottom plenum remains higher than in the other modes. Thus flow must go through the core during the time of interest. Recirculation flow coastdown during blowdown and reverse flow through the jet pumps on the broken side of the recirculation system does not occur until later in the transient when the top of the jet pumps are uncovered.

The recirculation pump in the unaffected line will continue to provide flow into the core inlet plenum thereby insuring positive core flow. Flow will be continuously injected into the core inlet plenum until the water level in the downcomer section drops sufficiently low to uncover the jet pump nozzles. By the time this occurs, rapid depressurization from steam blowdown causes the bottom plenum to flash forcing flow up the core and up through the jet pumps. The heat added to the core is not sufficient to cause flow reversal since the core heat flux will have dropped significantly at this time in the transient.

Typically the pressures in the key vessel volumes vary while the flow is coasting down as shown in Table 6.3-8.

It should be noted that the pressure is always higher below the core. Also the absolute pressure levels are well above the pressure at which the recirculation pumps will cavitate and thus flow will continue to be injected into the bottom plenum. Therefore, for a jet pump plant the flow through the core continues long enough to avoid violating the minimum critical heat flow ratio (MCHFR) while the heat flux is still high. For this reason the dryout tests are not applicable.

6.3.3.2.5 Historical Analysis of Radial Core Flow Distribution During Blowdown at 2527 MWt

For a design recirculation or steam line break, the core flow and MCHFR were calculated as a function of time for the first 10-20 seconds, with the flow through the core coasting down. Since for the maximum steam line break there is no temperature rise (the fuel clad temperature decreases monotonically from time zero), this discussion is directed primarily at the recirculation line break which results in a peak temperature of about 2000°F.

By use of a multi-channel model the core is orificed for normal operation to direct larger amounts of flow to the higher power bundles. Also, it is ensured by design criteria that the channel hydraulic characteristics are "stiff," i.e., that they have sufficient single phase pressure drop so as not to change the channel flow significantly if perturbations were to occur inside individual channels. For the recirculation line break, the reactor transient flow model shows that the flow through the core diminishes to about one-third of the rated value during the transient time of interest. Over such a flow range the overall core will act as a unit with respect to flow since each channel is exposed to the same pressure differential between the upper and lower plenum. Furthermore, the core heat flux is decreasing at about the same rate as the flow during this time, so that the overall core hydraulic characteristics with respect to exit voids do not change a great deal. Therefore, flow reapportionment due to pressure differences across the core should not occur during the transient.

Changes in void fraction across the core could cause reapportionment, but flow in any given channel is a weak function of exit voids. Furthermore, the heat flux over the entire core will decrease at the same rate due to the overall void increase or scrammed control rods. Thus, large relative void changes are precluded.

The question of flow reapportionment during the flow coastdown following a loss-of-coolant transient has also been analyzed quantitatively using the transient CHF analysis model described in Reference 41. This analysis was used to calculate the pressure drop across different fuel channels as a function of time, assuming no redistribution of flow from the initial steady-state distribution prior to the LOCA. The transient pressure drop across these fuel bundles was then compared. The variation in pressure drop from bundle to bundle at any time was always less than 10% for the two extremes. Physically in the actual case the pressure drop across each bundle must be the same as all other bundles at all times because they are all exposed to the same plenums. Therefore, there will be a small variation in the flow distribution with time between channels. However, the flow through any bundle will be proportional to the square root of the pressure drop; hence, the flow maldistribution between bundles will always be less than 5%. This is an insignificant variation for the loss-of-coolant transient.

For the reasons above, the assumption that the flow distribution through the core during a loss-of-coolant transient is unchanged from the steady-state distribution is justifiable.

6.3.3.2.6 Historical Analysis of Level Swell During Blowdown at 2527 MWt

Mixture level and local properties in a vessel during loss-of-coolant determine the core heat transfer environment and the nature of blowdown. Mixture level predictions were made with an analytical model[36] which has been compared with experiments, and reasonable level swell comparisons have been made with EVESR steam blowdown tests[42] and CSE blowdown data.[43]

It consistently has been stated and shown that calculated blowdown rates used in loss-of-coolant analyses are faster than expected.[44] Therefore an acceptable evaluation of the mixture level model should be uncoupled from the blowdown model. Ideal information to use in an evaluation of the mixture level model is a time-dependent plot of actual level, mass remaining in the vessel, and vessel pressure. Data usually published do not include all three measurements. However, pressure-time traces for bottom blowdowns exhibit a "knee," which is characteristic of a sudden change from liquid (or mixture) to vapor blowdown. It is, therefore, reasonable to use the mixture level model with a blowdown which closely predicts the given pressure trace. Time at which the measured knee appears can be compared with the time required for mixture level to reach zero elevation.

The following subsections compare predicted mixture level with selected measurements showing either a pressure-time knee or actual level measurement.

6.3.3.2.6.1 <u>Historical Analysis of Flowing Quality and Bottom Blowdown at 2527 MWt</u>

Blowdown rate depends on break geometry, vessel stagnation pressure, and stagnation enthalpy.[44] The actual value of stagnation enthalpy is determined partly by mixture properties in the vessel and partly by the fact that vapor bubbles rise through liquid. Figure 6.3-28 indicates blowdown from a bottom location. Symbols and subscripts used in the analysis are listed in Table 6.3-9.

Total blowdown rate W_B is composed of vapor and liquid flows W_{gB} and W_{fB}:

$$W_{gB} = X_F W_B = X_F G_c A_B \qquad (46)$$

$$W_{fB} = (1 - X_f) W_B = (1 - X_f) G_c A_B \qquad (47)$$

The term X_F is flowing quality, or vapor mass flow, fraction leaving the break. Critical flowrate per unit break area $G_c(P_o,h_o)$ can be considered a function of P_o and X_F if stagnation enthalpy h_o is expressed by:

$$h_o = h_f\ (P_o) + X_F h_{fg} (P_o) \qquad (48)$$

Vapor and liquid mass conservation equations are written as follows for the dotted control volume where elevation y is very small:

$$W_{gB} + W_g = 0 \qquad (49)$$

$$W_{fB} + W_f = 0 \qquad (50)$$

The terms W_g and W_f are upward flows of vapor and liquid[36] at elevation y, expressed by:

$$W_g = \frac{A_v V\ X}{v} \qquad (51)$$

$$W_f = A_v u \left[\frac{V}{v} (1 - X) - \frac{u}{v_f} \right] \qquad (52)$$

Where V is bubble rise velocity relative to the vessel, u is bubble rise velocity in stationary liquid, and v is local mixture specific volume based on X, which is local instantaneous vapor mass fraction. Equations 46 through 52 can be combined to give:

$$\frac{A_B}{A_v u} = \frac{1}{G_c v_f} \frac{X}{X - X_F} = f(P_o,\ X,\ X_F) \tag{53}$$

Equation 53 relates P_o, X, and X_F to the property $A_B/A_v u$. If flowing quality X_F is zero, then stagnation enthalpy is $h_f(P_o)$, and bottom blowdown of saturated liquid occurs; i.e., the condition for $A_B/A_v u$ to be satisfied for bottom liquid blowdown is that:

$$\left.\frac{A_B}{A_v u}\right| LIQ \leq \frac{1}{G_c\left[P_o,\ h_f\ (P_o)\right] \bullet v_f\,(P_o)} \tag{54}$$

However, if the above inequality is not satisfied, vapor bubbles will be entrained in the blowdown flow, and Equation 53 must be used to determine X_F. Bottom liquid or mixture blowdowns from 1000 psig characteristically produce X in the range 0 to 0.10. The corresponding effect on blowdown rate is small. It follows from Equation 53, therefore, that:

$$\frac{X_F}{X} \approx 1 - \frac{1}{G_c\, v_f \dfrac{A_B}{A_v u}} \tag{55}$$

Equation 55 can be used to help select test data for comparisons which can be closely approximated by liquid blowdown until the mixture level reaches the break.

6.3.3.2.6.2 <u>Historical Analysis of Blowdown Rates and Pressure Traces</u>

Calculated graphs already are available for liquid blowdown from 1000, 1250, and 2000 psia initial stagnation pressures.[45,46]

The graphs include a variable time scale with break area A_B as a parameter. Proper selection of an equivalent A_B* to bring theoretical and measured blowdown pressure traces into agreement will enable a better evaluation of the mixture level model.

6.3.3.2.6.3 Historical Analysis of Mixture Level Prediction

Mixture level has been calculated for vessel bottom blowdown from 1000 psia initial pressure with initial liquid level equal to 75% of the vessel overall height.

Where necessary, mixture level calculations can be made from the following equations[36] whenever X_F is greater than 0 from Equation 55:

$$\frac{Y_L^{(t^*)}}{H} = \frac{A_V u}{A_B} \frac{v_g^{(t^*)}}{v\ (o)} I_1(t^*) + \frac{Y_{L\,o}}{H} \frac{M_f^{(t^*)}}{M_{f\,o}} \left[v_g(t^*) \frac{S_{fg}(t^*)}{S_y(t^*) - S_{f(0)}} - v_{fg}(t^*) \right] \frac{1}{v_{f\,o}}$$

$$I_1(t^*) = -\int_o^{t^*} \frac{S_{f\,(o)} - S_f\,(t^*)}{S_g(t^*)} - S_{f\,(o)}\, dt^* \qquad (57)$$

The time t* is given by:

$$t^* = \frac{A_B}{M_o} t \qquad (58)$$

6.3.3.2.6.4 Historical Evaluation of Selected Tests for Comparison

Three tests were selected for this comparison from CSE,[43] Bodega,[47] and Humboldt[48] blowdowns. Pertinent experimental quantities are listed in Table 6.3-10.

Bodega and Humboldt vessels were cylindrical without internal mechanical components to obstruct internal flows. The CSE vessel contained a dummy core plate.

The equivalent break areas were determined so that theoretical and measured pressure-time curves were closely aligned up to the pressure trace knee. The quantity $A_B^*/A_v u$ was based on u = 1.0 ft/s bubble rise velocity, which seems to be more characteristic of small vessels. All three cases show that $A_B^*/A_v u$ is larger than the term $1/(G_{fc}U_f)$ initially so that mixture blowdown is ensured. (G_{fc} decreases as pressure drops so that mixture blowdown is ensured throughout the blowdown.) It follows that Equations 56 and 57 can be applied for necessary calculations.

Rather than calculate level curves for Bodega 30 and Humboldt 17, it was decided to make an approximate comparison with calculations already available from initial vessel pressures of 1000 psia. The tests begin at 1250 psia. Figures 6.3-29 and 6.3-30 show true vessel pressure traces with attention called to the knee. The lower half of each graph gives mixture level calculations based on 1000 psia and 75% initial water level. A dotted curve also is shown, based on the appropriate $A_B^*/A_v u$. When mixture level reaches zero, the pressure "knee" should occur. Even though the calculation is based on 1000 psia and the tests were run from 1250 psia, mixture level disappearance was predicted within 12.5% using the model described (this is a direct index of its accuracy).

The CSE data in Figure 6.3-31 include both pressure, mass remaining, and level for comparison with the mixture level model. Comparing only the level data in Figure 6.3-31, it is seen that a bubble rise velocity between 0.5 ft/s and 1.0 ft/s brackets the CSE-measured level. Note that the level swell model is not applied to the test data until the system is saturated. Note also that the 0.5-ft/s curve shows liquid vanishing at about the right time as indicated by the knee in the experimental curve. Thus reasonable agreement is also shown with the CSE data.

Additional comparison with the only other available data is addressed by Moody in Reference 11 in which the level rise data from EVESR[42] are given.

It is concluded from the comparisons with this data that the model has sufficient accuracy for predicting level rise.

6.3.3.2.7 Justification for Using the Hench-Levy CHF Correlation (Historical Information Prior to 1984)

Justification for using the Hench-Levy CHF correlation for a system undergoing a rapid depressurization can be shown by examining the fuel rod time constant, the vessel depressurization rate, and the core inlet flowrate. Fundamentally, the critical heat flux ratio (CHFR) is evaluated using a model which simulates the BWR 49 fuel rod bundle. The basic input consists of time varying pressure, core inlet flow, and core power which have been determined by other calculations. The model includes axial, radial, and local power distribution, as well as distributed loss coefficients. The BWR fuel rod time constant is approximately 10 seconds. The maximum vessel depressurization rate would be approximately 50 to 100 psi/s depending on the postulated break of either one recirculation line or one steam line at the vessel respectively. At rated core flow, it would take approximately 0.3 seconds for the coolant to travel through the core. Even under degraded flow conditions, the flow transit time in the core is not drastically altered primarily due to the voiding effect and its associated increase in velocity.

The average depressurization of the coolant per axial node (20 nodes/core) would be about 1 psi/s. Furthermore, since the time constant of the fuel is approximately 10 seconds, the node surface heat flux variation during the transit time of the coolant would be negligible. Therefore, for all practical purposes, the coolant is subjected to quasi-steady conditions because the changes in the key parameters are not rapid and the Hench-Levy steady state CHF data can be applied.

Another basis for applying the CHF correlation is that all evidence to date indicates that the use of steady-state CHF data for predicting transient CHF conditions is conservative even during truly rapid transients.[49] Therefore, by applying steady-state multirod CHF data to this transient analysis, there is an inherent factor of conservatism. Further margin exists in this analysis, especially at the end of the transient, because the actual improvement in CHF, which occurs at pressures down to 600 psi over that which occurs at 1000 psi, was neglected.

A third basis for applying the CHF correlation is that the steady-state data cover the entire range of flowrates and qualities which exist during the loss of coolant transient. Therefore, a firm basis for confidently predicting the CHF conditions throughout the transient exists.

The Hench-Levy correlation is used over the entire break range. Small breaks are similar to a pump trip transient since ac power is assumed to be lost at the initiation of the accident. The rate of change of all key parameters is very slow and the depressurization does not affect the pump coastdown rate. The coastdown momentum of the recirculation system provides more than adequate core flow to insure a MCHFR greater than unity and therefore very high nucleate boiling coefficients. Essentially all of the stored heat in the fuel would be removed within less than four fuel time constants (i.e., 30 seconds) of nucleate boiling. Therefore, after 30 seconds of nucleate boiling, the maximum core surface heat flux would be reduced to approximately 4% of the steady-state operating value. This is significantly lower than the pool boiling CHF under those conditions, and thus, a high heat transfer coefficient will exist. Note that the peak heat flux for Dresden is 354,000 Btu/hr-ft^2 during normal operation and that, within 15 seconds, the power will have decayed such that the peak heat flux is below 100,000 Btu/hr-ft^2. Below this heat flux flow is not required to maintain nucleate boiling, since the pool CHF is greater than this value. Also, the average heat flux in the core at time zero is only 118,000 Btu/hr-ft^2, which is below the pool boiling CHF virtually from the start of the event (pool boiling CHF at 1000 psia is greater than 129,000 Btu/hr-ft^2). Therefore, for small breaks, any time a fuel node is covered, a high nucleate boiling heat transfer rate can be assumed. The uncovered node is assumed to have a convection coefficient of zero.

For large breaks (greater than about 0.5 square feet), the flow coastdown is affected by the depressurization and must be calculated by the reactor transient flow model. The Hench-Levy correlation is used in the transient critical heat flux model to determine when the MCHFR drops to unity. The flowrates through the core are those calculated by the transient flow model which includes the coastdown flow and any contribution from any flashing in the bottom plenum when it occurs. Because the peak power bundle will reach the CHF condition long before the other bundles in the core, it is analyzed to determine the transient MCHFR in the reactor core. When one spot on one of the hot fuel rods dries out (when MCHFR = 1), the entire core is assumed to be insulated until either the MCHFR exceeds unity again or until the core is reflooded or core spay reaches rated flow.

Thus, there are also only two heat transfer correlations used for large break analyses during blowdown. When the MCHFR is greater than unity, based on the Hench-Levy CHF correlation, the Jens-Lottes heat transfer correlation is used to obtain the nucleate boiling heat transfer coefficient. The nucleate boiling heat transfer coefficient is of the order of 10,000 Btu/(ft^2-°F-hr) or higher. If the surface heat transfer coefficient is above a few hundred Btu/(ft^2-°F-hr), the peak clad temperature is unaffected by higher heat transfer coefficient values. This is because the heat transfer from the fuel is then limited by conduction through the fuel pin itself rather than the surface heat transfer coefficient.

When the MCHFR is less than unity, the surface heat transfer coefficient is assumed to be zero. This is conservative because film boiling heat transfer coefficients would exist which are of the order of 100 to 1000 Btu/(ft^2-°F-hr) and would actually provide additional cooling during the blowdown phase.

6.3.3.2.8 Justification for Using the Steady-State GEXL Correlation (Historical Information)

Application of the steady-state GEXL correlation during a loss-of-coolant transient was based on the fact that the use of the steady-state GEXL correlation had been shown to produce satisfactory agreement with experimental data.[50,37]

A total of 96 transient tests were performed at the ATLAS test facility using two 8x8 assemblies identified as 32B and 35C. Both of these were 148-inch long, electrically heated, 64-rod assemblies with axial flux shapes given by:

$$\psi = \frac{1.387 \ \sin \ (Z + 11.8\pi)}{171.6} \tag{59}$$

but with different local peaking factors. The transient tests included flow and power decay, flow decay with constant power, power ramp with constant flow, and power and flow ramp combinations. In 33 of the 96 tests, transition boiling was observed to occur. Nineteen of those 33 tests have been analyzed using the steady-state GEXL correlation.

A review of the analysis, Figure 6.3-32, shows that 8 of the 15 tests in which boiling transition was predicted by the steady-state GEXL correlation were within 0.35 seconds of the measured time to boiling transition. The results of the other seven tests predicted earlier (i.e., more conservative) times to transition boiling than the measured times. For the four tests that failed to predict transition boiling, a minimum critical power ratio of 1.009 or less was calculated.

These transient test results demonstrated the conservative predictive capabilities of the steady-state GEXL correlation and supported the use of the steady-state GEXL correlation in the loss-of-coolant accident analysis for 8x8 BWR fuel assemblies.

6.3.3.3 Integrated System Performance

6.3.3.3.1 Introduction

The purpose of this section is to summarize the integrated performance of the ECCS and to demonstrate that at least two independent core cooling subsystems are provided to ensure adequate core cooling over the entire spectrum of postulated reactor primary system breaks. Such cooling capability is even available concurrent with the improbable loss of all offsite ac power. Additional core cooling capability is actually available since the reliability of station ac power is extremely high.

The historical design basis of the ECCS subsystems was to prevent fuel clad melting over the entire spectrum of postulated primary coolant leaks. The historical range of break sizes for which each of the emergency core cooling systems was deemed capable of protecting the core against clad melting is shown in Figure 6.3-1. A solid bar indicates that range of break sizes for which an ECCS subsystem was deemed capable of preventing clad melting without assistance from any other system. A dashed bar indicates the break size spectrum for which a given subsystem acted in conjunction with another subsystem to prevent clad melting. The lower limit of capability of the core spray subsystem alone (point A for liquid breaks and point B for steam breaks) was defined as the smallest break size for which either of the two core spray subsystems could protect the core against clad melting indefinitely without assistance from any other emergency core cooling subsystem. The lower limit of the LPCI subsystem (point C for liquid breaks and point D for steam breaks) was similarly defined for three of the four available LPCI pumps operating.

The historical upper limit of the HPCI capability (point E for liquid breaks and point F for steam breaks) was defined as the largest break size for which the HPCI subsystem could protect the core for a period of at least 1000 seconds without assistance from any other emergency core cooling subsystem. The 1000 seconds was included in the definition because the HPCI subsystem requires a minimum vessel pressure to sustain the operation of the turbine. Since the decay heat generation continually decreases with time, a point will eventually be reached where the energy additions from decay heat will no longer be sufficient to maintain the required operating pressure for the HPCI turbine. However, this point is well below the pressure at which either the LPCI subsystem and/or the core spray subsystem is sufficient to keep the core cooled after the HPCI subsystem shuts off.

Note, however, that the ECCS acceptance criteria are now based on the requirements of 10 CFR 50.46 and the ECCS evaluations are performed in accordance with 10 CFR 50, Appendix K. LOCA break spectrum analysis is performed to determine the characteristics of the pipe break and ECCS performance that result in the highest calculated peak cladding temperature (PCT) during a postulated LOCA. The break characteristics addressed are the break location, break type and break size. The ECCS performance is determined by applying the Appendix K single active failure criterion.

6.3.3.3.2 Large Break Analysis

The current large break analysis assumptions and results are described in Reference 70 for GE14 and ATRIUM9B, and in Reference 78 for SVEA-96 Optima2. Long term cooling requirements for a large break are met by either: 1) supplying 4500 gpm of core spray flow to the top of the core and maintaining 2/3 core height, or 2) flooding the core to a level above the top of active fuel[77].

6.3.3.3.2.1 Deleted

6.3.3.3.2.2 GE Break Analysis for GE14, ATRIUM-9B and 9x9-2 Fuel at 2957 MWt

The GE LOCA analysis in Reference 70 uses the significant input parameters listed in Table 6.3-20b, which does not include instrument uncertainties. The recirculation line break spectrum was analyzed using the nominal and Appendix K assumptions and inputs. The limiting case was determined to be the diesel generator failure (same as 125-Vdc battery failure) without HPCI at the initial operating conditions identified in Table 6.3-20b. Table 6.3-13c provides the sequence of the event analyzed for the limiting case, and Table 6.3-19c identifies the leakage accounted for in the analysis. Table 5-1 of Reference 70 shows the cases analyzed for GE14 and the legacy fuel. Other potentially limiting combinations of single failures in Table 6.3-21b were analyzed at the limiting break sizes.

Other conditions analyzed in Reference 70 include single loop operation (SLO), maximum extended load line limit (MELLL), increased core flow of 108% of rated, SRV out of service and feedwater heater out of service. Impact of a final feedwater temperature reduction of 120ºF was evaluated in Reference 77.

To assure that SLO at 2957 MWt will not result in calculated PCTs that exceed those for two-loop operation, analysis was performed to determine a SLO LHGR and MAPLHGR multiplier that results in a calculated nominal PCT for SLO that is less than the nominal PCT for two-loop operation. The two-loop break spectrum is representative of the SLO break spectrum. The analysis in Reference 70 shows that the design basis accident (DBA) is the limiting case for SLO. SLO will affect the DBA results more than the smaller breaks. With breaks smaller than the DBA, there is a longer period of nucleate and/or film boiling prior to fuel uncovery to remove the fuel stored energy. Table 5-8 of Reference 70 shows the results for SLO analysis.

The higher rod line in the maximum extended load line limit analysis (MELLLA) region permits reactor operation at 95% of rated core flow for a power level of 2957 MWt. Reference 70 cites the generic studies that show no MAPLHGR multiplier is required for low core flow operation for the BWR-3 plant class, which includes Dresden. Table 5-6 of Reference 70 shows the results for core flow at MELLLA conditions.

Reference 70 addresses the effect of operation at 2957 MWt and increased core flow condition corresponding to 108% of rated core flow. The limiting event of a DBA recirculation suction line break and diesel generator failure without HPCI was analyzed for the ICF condition using both nominal and Appendix K assumptions. Table 5-5 of Reference 70 shows the results for ICF analysis.

The impact on LOCA results due to a feedwater temperature reduction of 100 ºF was evaluated at extended power uprate (EPU) conditions and the pre-EPU power level using the same ECCS parameters as normal feedwater temperature case. Impact of a final feedwater temperature reduction of 120ºF was evaluated in Reference 77. Reference 70 includes evaluation of the feedwater heater out of service case and provides the results for the feedwater temperature reduction in Table 5-7. Table 5-9 of Reference 70 provides results for the limiting small break with one ADS out of service and the required LHGR and MAPLHGR reduction multiplier.

Reference 74 identifies the equipment out-of-service and flexibility options that have been evaluated as part of the LOCA analysis and, except for SLO and one ADS out of service, they can be accommodated during LOCA events without additional restrictions applied to plant operation. When the plant is operated with both SLO and ADS out of service at the same time, the lower of the SLO LHGR and MAPLHGR multiplier and ADS out of service LHGR and MAPLHGR multiplier is applicable and will provide adequate protection for both conditions.

To assure long-term cooling of the fuel, the minimum requirements of 4500 gpm of core spray flow to the top of the core and 2/3 core height water level, or full height water level coverage to the top of the active fuel should be satisfied.

The MAPLHGR limits for 9x9 fuel during normal operation as a function of exposure were determined based on the limiting operating conditions for the identified limiting LOCA break. The ANF MAPLHGR limits also protect against exceeding fuel design limits for 9x9 fuel. When the fuel design limit is more restrictive than LOCA-ECCS criteria, the LOCA-ECCS results will be significantly below the 2200°F criteria at higher exposures. This is the case for Dresden Units 2 and 3 with ANF 9x9 fuel. The exposure-dependent MAPLHGR limits are shown in Figure 6.3-59, and the computed points used to determine this curve are given in Table 6.3-12. The MAPLHGR limits apply to ANF 9x9 fuel in the Dresden reactors during normal operation for both the initial and subsequent reloads of the current 9x9 fuel design.

All calculations were performed with the NRC-approved EXEM/BWR ECCS Evaluation Model in accordance with 10 CFR 50, Appendix K. Operation of the Dresden reactors with ANF 9x9 fuel at or below the MAPLHGR limits of Figure 6.3-59 satisfies the criteria specified by 10 CFR 50.46, and assures that the emergency core cooling system for the Dresden reactors will meet the NRC acceptance criteria for LOCA breaks up to and including the double-ended severance of a reactor coolant pipe. The acceptable criteria are as follows:

A. The calculated peak fuel element clad temperature does not exceed the 2200°F limit.

B. The amount of fuel element cladding which reacts chemically with water or steam does not exceed 1% of the total amount of Zircaloy in the reactor.

6.3.3.3.2.3 Westinghouse LOCA Analysis

The Westinghouse BWR LOCA analysis in support of operation at 2957 MWt with SVEA-96 Optima2 fuel was performed using bounding input parameters from the Dresden units. The Dresden analysis inputs are identical for Dresden Units 2 and 3 with the exception of the LPCS delivered flows and shroud leakages. The objective of the analysis was to provide assurance that the most limiting break size, break location, and single failure combination have been considered for the plant and that the results for the DBA LOCA meets the acceptance criteria of 10CFR50.46. As a result of this analysis, it has been shown that the ECCS meets all the requirements of 10CFR50.46, even in the event of the loss of normal station auxiliary power.

Independent of fuel type, additional ECCS cooling capability exists from the feedwater condensate systems in the more probable event that station auxiliary power is available.

The recirculation line break spectrum was performed with the hot assembly operating at a constant conservative operating limit and the heat-up analysis at a fixed nodal peaking factor and exposure to ensure that the LOCA response could be compared on the same basis.

The peak cladding temperature (PCT) results are shown for all break sizes analyzed in Reference 78. The PCT does not represent the current licensing basis LOCA PCT, but were used to establish the limiting break size, location and single failure. The single failure of the LPCI injection valve was the limiting failure for the large recirculation line breaks. With this single failure, the LPCI injection valve is assumed to fail in the closed position. Therefore, no coolant is injected by the LPCI subsystem. As shown in Table 6.3-21c, this single failure results in the lowest injection rate and therefore results slowest recovery of two-phase cooling conditions in the core.

The ECCS performance for SVEA-96 Optima2 fuel under single loop operation was evaluated at 72.2% of 2957 MWt using the Westinghouse BWR LOCA methodology. The single loop system performance is performed in the same manner as for two loop operation with the exception that it is initialized at a different statepoint [72.2% of rated power and 55.1% of rated flow]. The break is placed in the suction line of the active recirculation loop as this reduces the beneficial effect of pump coastdown during blowdown.

Without MAPLHGR reduction, the peak cladding temperature for single loop operation is higher than the corresponding two-loop values. However, as shown in Reference 78, the results of the two-loop operation peak cladding temperatures remain limiting provided that single loop operation assumes a MAPLHGR multiplier of less than the multiplier given in Reference 78 at the most limiting exposure.

To ensure that the two-loop licensing basis PCT remains applicable, a MAPLHGR reduction is required for single loop operation.

The Westinghouse BWR LOCA methodology was used to support operation at 2957 MWt with SVEA-96 Optima2 fuel. The analyses were performed at 102% of rated power and 108% of rated core flow (ICF operation) to establish MAPLHGR limits. Application of the methodology at 95.3% of rated core flow (MELLLA operation at 2957 MWt) showed no adverse effect due to operation at the decreased core flow.

Exposure dependent MAPLHGR limits were determined for SVEA-96 Optima2 fuel types to support operation at 2957 MWt. The MAPLHGR limits were established using Westinghouse BWR LOCA methodology. LHGR limits based on fuel thermal-mechanical design limits are established separately in the Westinghouse BWR reload methodology. Cycle specific MAPLHGR limits for two loop and single loop operation will be documented in supplements to the reload licensing submittals.

The calculated peak cladding temperature for the ECCS-LOCA analysis may be impacted by LOCA model error correction and/or input changes identified subsequent to the original analysis; the impact of these changes on peak cladding temperature is reported in accordance with 10 CFR 50.46, as discussed in Section 6.3. Based on the reported errors and input changes, the current licensing basis peak cladding temperature value for Westinghouse Optima2 fuel is shown in Table 6.3-12f, which remains below the 10 CFR 50.46 acceptance criterion of 2200° F. All other 10 CFR 50.46 acceptance criteria are satisfied.

Tables 6.3-4c and 6.3-12f summarize the Westinghouse analysis results for Dresden units 2 and 3. The analyses presented are performed in accordance with NRC requirements, conditions and limitations and demonstrate conformance with the ECCS acceptance criteria of 10CFR50.46 as shown in Table 6.3-12f.

Reference 78 identifies the equipment out of service and flexibility options that have been analyzed as part of the Westinghouse LOCA analysis.

Westinghouse has determined that for Optima2 fuel, core spray or core re-flooded to the top of active fuel is required for long term cooling. Testing of the amount of spray flow required to keep SVEA-96 Optima2 fuel rods quenched is described in Reference 88. Their conclusions demonstrate that when there is sufficient water from LPCI or core spray to maintain the 2/3 core height water level, then a core spray of 4500 gpm (based on minimum required 0.4 core spray distribution factor) to the top of the core is essential to meet the fuel safety limits for long term cooling.

6.3.3.3.3 Historical Large Break Analysis - Recirculation Line

The double-ended recirculation line break is one of the bases for the design of the emergency core cooling system and the containment response calculations. The containment response is discussed in Section 6.2.1.

This accident is analyzed with a nine-node reactor simulation model. The nine nodes are the lower plenum, the core, the upper plenum, the leakage region, the separation zone, the steam dome, the downcomer, and the two recirculation loops. The jet pump modeling assumes that conservation of momentum and drive pump trip can be included. The core and leakage regions each have 10 common pressure subnodes. Included in the model is a method of calculating the movements of the liquid level in the separation region. A vapor to liquid relative velocity of 1 ft/s is assumed in these calculations.[36,54]

It is assumed that the reactor is operating at 2527 MWt when a complete circumferential rupture instantaneously occurs in one of the two recirculation system suction lines. An interlock ensured that the valve in the equalizer line between the jet pump headers will be closed when both recirculation pumps are operating (see Section 7.3); thus, the area available for coolant discharge from the reactor vessel would be the sum of 10 jet pump nozzle areas and the cross-sectional area of the main recirculation line. On Unit 3, the equalizing line has been removed. On Unit 2, both of the equalizing valves and one of the equalizer bypass valves are closed and de-energized. The other equalizer bypass valve is maintained open and de-energized.

Immediately after the break, critical flow would be established at the breaks, and the total flow would be approximately 35,000 lb/s. The large increase in core void fraction that would be caused by the decreasing vessel pressure would be sufficient to render the core subcritical. High drywell pressure would initiate a mechanical scram of the control rod system in less than 1 second. In 6 seconds the liquid inventory in the downcomer and the separator region of the vessel would be depleted, and the break flow would switch from liquid to vapor. This would result in a large increase in the vessel depressurization rate.

Core inlet flow and vessel pressure are shown in Figure 6.3-60. For this accident, it is assumed the normal ac power supply to the recirculation pumps fails at the time of the accident. The drive flow in the 10 jet pumps of the broken loop very rapidly reverses to critical flow at the nozzles. However, the rapid flow from the downcomer region to these nozzles inhibits reverse flow in the associated jet pump throats and diffusers. In the meantime, the rotating energy stored in the pump and motor-generator set of the other recirculation system is used to provide continuing flow into the lower plenum. This flow is assumed to cease when the falling level in the downcomer reaches the jet pump suction level. It is also assumed (conservatively) that feedwater flow ceases at the time of the accident due to loss of electrical power, without any coastdown time.

When the break flow in the severed recirculation line changes to steam, the very high vessel depressurization rate will result in immediate and vigorous flashing of the water in the lower plenum which will force flow of two-phase mixture up through the core and through the 20 jet pump diffusers. Because reverse flow in the latter is subject to considerable hydraulic resistance, approximately 50% of the exiting flow would go via the core. As the lower plenum inventory becomes depleted, the mass flow rate into the core will diminish (see Figure 6.3-60).

Calculations indicate that the reactor vessel will completely depressurize in approximately 30 seconds. Some water will remain in the vessel after blowdown, but it is conservatively assumed that the entire vessel liquid inventory is lost. Either the low-low water level sensor in conjunction with low pressure in the reactor vessel or high drywell pressure sensor would initiate ECCS (i.e., core spray subsystem and LPCI subsystem). With auxiliary power available, both core spray subsystems and the entire LPCI subsystem would start up and would each be delivering rated flow to the vessel within 30 seconds after the accident occurs and within 14 seconds after the core becomes steam blanketed. Figure 6.3-61 shows the vessel pressure and water inventory transient for the LPCI mode (three pumps).

The thermal transient performance of the reactor core following the postulated LOCA was evaluated using a digital computer code model. The model included an array of 49 cylindrical fuel rods surrounded by a channel. The model allowed for 10 radial nodes within the fuel; 20 axial nodes within the coolant; and for time varying coolant pressure, coolant flowrate, and core power operation. Temperature dependent thermal properties for the fuel and cladding materials were also included. The model accounted for fluid expansion and included subcooled, nucleate boiling, and film boiling heat transfer mechanisms.

The transient MCHFR following the accident was calculated using the computer model with the conservative assumption that the core axial power generation distribution is as shown on Figure 6.3-62. Furthermore, the core was assumed to be initially operating at 2527 MWt with a peak linear power generation of 17.5 kW/ft. The results of these initial conditions indicate that the steady-state operating MCHFR would be approximately 1.9. MCHFR has been superseded in later analyses by minimum critical power ratio (MCPR). Since these quantities are not interchangeable, the terminology in this analysis has not been revised.

The transient MCHFR was calculated using the Hench-Levy correlation for mass velocities greater than 0.75 M lb/(hr-ft^2). The GE-APED transient CHF correlation given in Equation 60 below and shown on Figure 6.3-63 is for loss-of-coolant analyses at mass velocities less than 0.75 M lb/(hr-ft^2). The correlation was drawn below all existing APED CHF data at mass velocities below 0.5 M lb/(hr-ft^2) and 0.75 M lb/(hr-ft^2), respectively. The correlation does not take advantage of the increase in CHF for decreasing pressure, therefore, it is conservative for pressures less than 1000 psia.

CHF = 0.84 - X [M Btu/(hr-ft^2)] for G less than 0.5 M lb/(hr-ft^2) (60)
= 0.80 - X [M Btu/(hr-ft^2)], for G from 0.5 to 0.75 M lb/(hr-ft^2)

The reactor transient MCHFR calculated using the computer model is given on Figure 6.3-64. As is evident from Figure 6.3-64, the MCHFR decreases initially to 1.35 at 2.0 seconds after the accident occurs. The MCHFR then increases transiently, and reduces to less than 1.0 at approximately 16 seconds. Steam blanketing of the reactor core would then occur providing steam cooling, but this phenomenon was conservatively neglected for the analysis (i.e., the heat transfer coefficient set to zero). Therefore, the hot bundle would be cooled by nucleate boiling heat transfer for 16 seconds (i.e., approximately two fuel time constants). The average bundle would be boiling approximately 4 seconds longer than the hot bundle. Hence, nucleate boiling heat transfer was assumed to cease at 20 seconds for the average bundle.

Figures 6.3-65 and 6.3-66 are plots of the peak clad temperatures in both the hot and average bundles for the cases of:

A. One core spray subsystem operating (Figure 6.3-65), and

B. Three LPCI pumps operating (Figure 6.3-66).

Figure 6.3-66 shows that under the worst circumstances (i.e., core cooling by the flooding action of three LPCI pumps), the peak clad temperature in the hot bundle would not exceed 2050°F. With one core spray subsystem operating, Figure 6.3-65 shows that the peak clad temperature would be only 1700°F.

6.3.3.3.4 Historical Intermediate Break Analysis

For break sizes below the lower limit of the unassisted core spray subsystem (points A and B on Figure 6.3-1) or LPCI subsystem (points C and D), the HPCI subsystem or ADS acts to depressurize the nuclear boiler, allowing either the core spray subsystem or the LPCI subsystem to provide core cooling. In addition, for break sizes in this range, flow from the feedwater-condensate system will protect the core when normal auxiliary power is available.

The intermediate break range here is defined between the limits of the unassisted HPCI (point E) and the unassisted core spray or LPCI (points A and C), in which one of the high pressure subsystems (HPCI or ADS) works in conjunction with one of the low pressure subsystems (LPCI or core spray) to provide core cooling.

An example of the integrated HPCI-LPCI subsystem performance is shown on Figure 6.3-67 for a typical intermediate break size. The phenomena during the initial phases of the transient are seen to be the same as that discussed in Section 6.3.3.1.3 for the HPCI performance alone (i.e., the core stored energy is being removed and the main turbine pressure regulator acts to maintain a relatively constant vessel pressure). When the HPCI subsystem is actuated, an increase in level occurs due to the depressurization caused by the HPCI operation. Note that when the LPCI flow is superimposed on the HPCI flow, core uncovering does not occur even for this intermediate break size.

In fact, with the HPCI/LPCI subsystem combination, core uncovering is prevented for break sizes up to about 0.22 square feet which is close to the lower limit of capability of the unassisted LPCI subsystem. Similarly, the core spray subsystem acting in conjunction with the HPCI subsystem prevents core uncovering for break sizes up to about 0.2 square feet (Figure 6.3-68) which is equal to the lower limit of the unassisted core spray subsystem performance capability.

For much larger breaks, the HPCI subsystem has less effect on core spray or LPCI performance, and the results are more like those shown in Sections 6.3.2.1 and 6.3.2.2, respectively.

The integrated performance of the ADS in conjunction with the LPCI subsystem or core spray subsystem for the intermediate break sizes is very similar to the performance of these same combinations for the small break sizes, except depressurization is more easily accomplished with increasing break size. For this reason, the integrated performance of these subsystem combinations is shown in the next section.

6.3.3.3.5 Small Break Loss-of-Coolant Accident Analysis

6.3.3.3.5.1 Small Break Analysis at 2757 MWt

The GE small break LOCA analysis assumptions and results are described in Reference 70 for GE14 and ATRIUM9B. The Westinghouse small break LOCA analysis at 2957 MWt is discussed in Reference 78 for SVEA-96 Optima2.

6.3.3.3.5.2 Historical Small Break Analysis at 2527 MW_t

For small breaks the core is protected by the HPCI subsystem (up to point E for liquid breaks and point F for steam breaks on Figure 6.3-1), and by the core spray subsystem or LPCI subsystem in conjunction with the ADS. With normal auxiliary power available, the feedwater-condensate systems will never permit core uncovering for these break sizes.

The performance of the HPCI subsystem for these small break sizes was described in Section 6.3.3.1.3.

Generally the ADS/core spray or ADS/LPCI combinations will not prevent core uncovering as the HPCI subsystem or feedwater-condensate systems do for the small break sizes. However, the ADS is designed to allow the LPCI or core spray subsystems to prevent clad melting for all break sizes down to and including a zero break size.

An example of the ADS/core spray subsystem performance at 2527 MW_t for a typical small break is shown in Figure 6.3-69. The sequence of events during the initial phase of the transient is similar to that discussed in Section 6.3.2.3 for the HPCI subsystem performance. The important difference in the system response for the automatic depressurization case is that vessel pressure hovers near rated for a much longer period of time since the HPCI is assumed to be inoperable and the ADS is not actuated until 120 seconds after the low-low trip level is reached. An additional obvious difference is the more rapid loss of liquid inventory due to the higher vessel pressure and absence of HPCI makeup. When the ADS is actuated, a marked increase in the vessel pressure reduction rate occurs due to the critical steam flow through the relief valves. This increased depressurization rate causes a corresponding increase in water levels inside and outside the shroud. When the water level inside the shroud drops to the top of the jet pumps the water level is sustained except for flashing due to depressurization and boiloff.

The level outside the shroud continues to drop rapidly until the core spray subsystem restores the water level inside the shroud to the top of the jet pumps. At this level the water from inside the shroud begins spilling over into the region outside the shroud, thereby raising the water level outside the shroud.

A similar example of the ADS/LPCI subsystem combination performance at 2527 MW_t is shown in Figure 6.3-70. The sequence of events is very similar to that discussed above for the ADS/core spray subsystem performance.

The performance cases illustrated above are typical for the ADS/core spray subsystems or ADS/LPCI subsystem combinations in the small break region. As larger break sizes are considered, the margin between the time the core is cooled and the time at which clad melting would occur is increased. As much larger breaks are considered, the performance of these subsystem combinations becomes the same as the core spray alone or LPCI alone, as discussed in Sections 6.3.2.1 and 6.3.2.2, respectively.

In addition to the systems discussed, the two control rod drive pumps are each capable of supplying makeup to the reactor vessel at the rate of 100 gal/min. The control rod drive pumps are powered by Buses 23 and 24 and can be energized through the emergency Buses 23-1 and 24-1. Each control rod drive pump is 250 hp which is within the capability of each diesel generator. It should be noted that energization of these pumps through the emergency buses is a manual operation performed by the control room operator. Therefore, these pumps are not considered part of the ECCS for small breaks.

6.3.3.3.5.3 GE Small Break Analysis for GE14, ATRIUM-9B and 9x9-2 Fuel at 2957 MWt

The small break analysis was performed similar to the large break. The analysis in Reference 70 assumes all ADS valves operate to reduce vessel pressure during events that do not have HPCI available. The LOCA acceptance criteria for PLHGR and MAPLHGR shown in Table 4-2 of Reference 70 cannot be satisfied if one or more ADS valves are out of service unless for one ADS out of service LHGR and MAPLHGR reductions are applied.

6.3.3.3.5.4 Westinghouse Small Break Analysis for SVEA-96 Optima2 Fuel at 2957 MWt

The Westinghouse small break LOCA analysis for SVEA-96 Optima2 is discussed in Reference 78. The limiting small break in the recirculation line occurred for a 0.15 ft^2 break downstream of the LPCI injection point with single failure of HPCI. For recirculation line breaks larger than this, the loop select logic is assumed to select the intact loop, in which case none of the coolant injected by LPCI is lost out the break before it enters the reactor vessel. The Westinghouse small break LOCA analysis assumes that all ADS valves operate for the cases with single failure HPCI. If one of the ADS valves is out-of-service, a MAPLHGR reduction is necessary to remain within the licensing limits.

6.3.3.3.6 Steam Break Loss-of-Coolant Accident Analysis

6.3.3.3.6.1 Deleted

6.3.3.3.6.2 Historical Steam Break Analysis

Discussion and illustration of the ECCS performance capability is purposely directed toward the liquid breaks below the core. In general the ECCS design criterion of no clad melting is more easily satisfied for steam breaks than for liquid breaks because the reactor primary system depressurizes more rapidly with less mass loss for steam breaks than for liquid breaks. Thus the ECCS performance for a given break size improves with increasing break flow quality.

The most severe steam pipe break would be one which occurs in the drywell, upstream of the flow limiters. Although this analysis assumed that the isolation valves would close within 10.5 seconds (10-second valve action time plus 0.5-second instrument response), a break in this location would permit the pressure vessel to continue to depressurize to the drywell. As serious as this accident is, however, it does not result in thermal-hydraulic consequences as severe as the rupture of a coolant recirculation pipe. For purposes of analysis, the steam pipe break pre-accident conditions were assumed to be:

A. Reactor power of 2527 MWt;

B. Steam dome pressure of 1000 psia;

C. Normal water level in the pressure vessel; and

D. Loss of auxiliary power coincident with steam pipe break.

The accident sequence would proceed as follows:

A. An instantaneous guillotine severance of the steam pipe which occurs upstream of the steam flow restrictors would permit flow to accelerate to its limiting critical flow value in the break at the pressure vessel end and at the flow-limiter end.

B. The steam loss in excess of the generation rate would result in rapid depressurization of the pressure vessel and the steam pipes.

C. The first 10 seconds of this accident are similar to the break outside the drywell discussed in Section 15.6.4. However, for the break inside the drywell, closure of the isolation valves reduces the blowdown rate but does not prevent the vessel from depressurizing. The vessel would continue depressurizing through the pipe from the pressure vessel to the break.

During a steam line break, the reactor would be shut down immediately by the voids which would result from the depressurization. A mechanical scram would be initiated by position switches in each main steam isolation valve (MSIV) at approximately 10% valve closure so control rod insertion would begin within 1.5 seconds after the break. Low water level, which would occur later in the blowdown, would also initiate a scram.

The reactor coolant loss through blowdown consists of three intervals: steam blowdown; then mixture blowdown; and finally steam blowdown again. After the accident, steam in each end of the break is accelerated to critical flow. In the short pipe from the pressure vessel, the steam flow will be accelerated to about 3800 lb/s. At the other end of the break, flow would be critical at the steam flow restrictor with a maximum steam flow of 1400 lb/s.

As the reactor vessel depressurizes, the water level rises due to flashing. When the level reaches the steam pipes, the break flow changes from steam blowdown to mixture blowdown. Mass flowrate through the break increases sharply to 12,000 lb/s, at this time, as shown in Figure 6.3-71. At 10.5 seconds the isolation valves are closed, which reduces the blowdown rate. As coolant is expelled and the pressure decreases, the water level in the pressure vessel will drop below the steam pipe elevation and steam blowdown will begin again at approximately 50 seconds. The system depressurization rate would increase, but the mass flowrate through the break would decrease. The long-term pressure transient and water level transient are shown in Figures 6.3-72 and 6.3-73 for the cases of one core spray pump and three LPCI pumps operating.

The reactor core inlet flow transient was calculated with an analytical digital computer code model which simulates the entire vessel. Included in the model is the reactor core heat addition, pump momentum, distributed pressure drops, critical flow, and the effect of water level movements in the vessel. A vapor bubble to liquid relative velocity of 1 ft/s is used in the model.[54,11] The calculated core inlet flow transient is shown in Figure 6.3-74. The initial rapid reduction in core inlet flow is due primarily to the vessel rapid depressurization rate and the corresponding larger pressure differential across the recirculation drive pumps. The assumed simultaneous loss of the normal ac power supply with the postulated accident would cause a loss of the electrical power to pumps thereby resulting in pump coastdown.

The thermal hydraulic transient performance of the reactor fuel was evaluated using a digital computer code transient model which simulates a fuel bundle. Included as input are the dimensions of the bundle, thermal properties of the coolant and the fuel, and time varying pressure and flow, thereby allowing for the evaluation of the condition of the fuel throughout the accident.

The primary purpose of the thermal hydraulic performance analysis of the fuel bundle is to determine if adequate core cooling exists during the blowdown to prevent an overtemperature condition and possible perforation of the fuel rod cladding. The highest power fuel bundle in the core was assumed to be operating at a peak power generation of 17.5 kW/ft with the axial peaking power profile given in Figure 6.3-62. Furthermore, these initial operating conditions would result in an operating MCHFR close to the mechanical design limit of 1.9. The results of the thermal hydraulic transient performance analysis (i.e., MCHFR) of the fuel is shown by Figure 6.3-75. The MCHFR would initially decrease to approximately 1.3 at 2 seconds after the accident and then would continuously increase transiently to 25 at approximately 40 seconds. Forty seconds (i.e., 4 to 5 fuel time constants) of nucleate boiling would remove essentially all of the core stored energy, and therefore, the fuel (UO_2) and the cladding would be at the same temperature (500°F). The continuing depressurization of the reactor vessel would cause the saturated liquid inventory to continually flash. This production of steam within the liquid coupled with the steam produced due to decay heat would result in the level of the two phase mixture being well above the top of the core throughout the entire transient. The two-phase mixture swell would cool the core as observed in the flooding tests.[55]

Approximately 60 seconds after the break occurs, the core spray subsystem and the LPCI subsystem would start to inject coolant into the vessel. For this analysis it was assumed that either the core spray or the three LPCI pumps were operating.

Therefore in summary, the core would remain cooled throughout the entire transient and the cladding integrity would be maintained, since the clad temperature is falling at all times during the transient.

6.3.3.3.6.3 GE Steam Break Analysis for GE14, ATRIUM-9B and 9x9-2 Fuel at 2957 MWt

The steam break analysis was performed similar to the large break analysis. As shown in Table 5-3 of Reference 70, the results for these postulated breaks are significantly less severe than the postulated recirculation line breaks.

6.3.3.3.6.4 Westinghouse Steam Break Analysis for SVEA-96 Optima2 Fuel at 2957 MWt

Steam line breaks, both inside and outside containment, are evaluated in Westinghouse analysis. As shown in Reference 78, the results for these postulated breaks are significantly less severe than the recirculation line breaks.

6.3.3.3.7 Effects of Break Location for Loss-of-Coolant Accident Analysis

6.3.3.3.7.1 Deleted

6.3.3.3.7.2 Historical Effects of Break Location

The ECCS bar chart (Figure 6.3-1) shows the capability of the various ECCS subsystems to meet core cooling criteria as a function of break size for both liquid and steam line breaks. The bar chart considers general types of breaks on both ends of the break flow quality spectrum so that all possible break flow conditions are included. Not included in the bar chart are those types of breaks which incapacitate a system. For example, breaks in the feedwater line which is used for HPCI injection are obviously not covered by the HPCI subsystem. However, a break in the other feedwater line is protected by the HPCI and/or core spray or LPCI as indicated by the bar chart depending on the size of the break.

Thus, the only breaks which are not covered by the bar chart are specific sizes of breaks in particular lines. These are considered below.

For breaks in the feedwater line used for HPCI injection, the ADS provides an independent backup to allow adequate core cooling by either core spray or LPCI. The maximum temperatures would be less than those shown in Figure 6.3-66 for any postulated break size in the feedwater line.

For breaks in the LPCI injection lines inside the drywell the LPCI logic would detect the location of the break, thereby causing LPCI flow to be injected into the unbroken loop if the break were sufficiently large to jeopardize the LPCI function. Thus, these break locations in the drywell will not temperatures would be less than those shown in Figure 6.3-66 for any postulated break size in the feedwater line.

For breaks in the LPCI injection lines inside the drywell the LPCI logic would detect the location of the break, thereby causing LPCI flow to be injected into the unbroken loop if the break were sufficiently large to jeopardize the LPCI function. Thus, these break locations in the drywell will not affect LPCI capability. The two core spray subsystems provide two independent backups even in the event of LPCI injection valve failure. Even with external ac power loss one core spray loop will be available and is adequate to protect the core.

For breaks in the core spray line, the LPCI and the second core spray are available as independent backups. With the loss of external ac power, the LPCI is available and core spray would be available unless the break happens to be in the core spray injection line of the preferred core spray loop, statistically a highly unlikely event. In this case, LPCI, HPCI, and ADS are available. The LPCI subsystem in conjunction with HPCI or ADS is adequate for any break size in general, and thus any break size in the core spray line is covered. For the loss of external ac power case, even if the break were postulated in the preferred core spray loop and failure of the LPCI admission valve were postulated, operator action would still allow adequate core cooling. Because the spray nozzles limit the leakage, the operator would have approximately 20 minutes in which to detect that the LPCI admission valve had failed to open and to allow transfer of diesel power to the other core spray loop in time to meet the core cooling criteria. The fact that the valve did not open would be known within approximately 10 minutes by means of the low flow alarms on the LPCI subsystem. Thus, ample time is available for the operator to disengage the LPCI subsystem and actuate the second core spray loop.

It is concluded, therefore, that the core cooling criteria are met for any particular break location even with a loss of external ac power simultaneous with the most severe single component failures.

6.3.3.3.7.3 <u>GE Analysis of Effects of Break Locations for GE14, ATRIUM-9B and 9x9-2 Fuel at 2957 MWt</u>

The nonrecirculation break analysis was performed similar to the large break analysis. As shown in Table 5-3 of Reference 70, the results for these postulated breaks are significantly less severe than the postulated recirculation line breaks.

6.3.3.3.7.4 <u>Westinghouse Analysis of Nonrecirculation Breaks for SVEA-96 Optima2 Fuel at 2957 MWt</u>

The nonrecirculation break analysis was also performed in the Westinghouse LOCA calculation. As shown in Reference 78, the results for these postulated breaks are significantly less severe than the postulated recirculation line breaks.

6.3.3.3.8 <u>Historical Break Spectrum Coverage at 2527 MWt</u>

To further demonstrate the capability of the ECCS, the peak clad temperature at 2527 MW_t as a function of break size for various ECCS combinations is displayed in Figure 6.3-21. In all cases the no clad melting criteria was satisfied across the entire break size spectrum. The temperatures shown were determined with the aid of the core heatup code[56] utilizing such assumptions as unlimited steam availability for metal-water reaction and no credit for steam cooling or level swelling. More realistic calculations including the effects of steam cooling and level swelling would lower the peak temperatures by several hundred degrees, particularly for the small or intermediate breaks.

Figure 6.3-76 shows the percentage of fuel rods perforated at 2527 MWt as a function of break size for the various combinations of emergency core cooling equipment. The percentages shown were based on the fission gas distribution in the core at the end of an equilibrium cycle and the actual perforation stress as a function of clad temperature determined from GE tests.[1]

Even these results are conservative since the clad temperatures used for the calculations were those shown in Figure 6.3-21 which are also conservative.

6.3.3.3.9 Historical Analyses Supporting ECCS Clad Melt Criteria at 2527 MWt

The ECCS criteria include a criterion of no clad melt as a design objective. Due to the potential effects of clad perforation or shattering following blowdown, the overall ECCS capability to limit fuel clad temperatures to levels where the integrity of clad geometry would be maintained has been considered. In this regard, the results of all experimental programs and analyses that support the design and performance of the ECCS are discussed in the following subsections.

The no clad melt criterion was selected for the purpose of designing and sizing ECCS equipment in a consistent manner. The sizing of the ECCS equipment to this criterion of no clad melt necessitated the thermal performance analysis of the core following the postulated break. In order to provide a consistent design approach for ECCS sizing, simplified models and grossly conservative assumptions were used to calculate the core heatup transient. Some basic assumptions included:

A. Dryout cooling during blowdown for the design (recirculation line) break;

B. Core insulated when half uncovered for small break;

C. No steam cooling; and

D. 100% steam availability for metal-water reaction.

Having sized the ECCS equipment in this manner, more refined models have been used to evaluate the actual performance. Instead of simply neglecting cooling phenomena known to exist, a conservative estimate has now been included for most of the important phenomena. Using these more refined models, the performance of the Unit 2 ECCS across the complete break spectrum has been evaluated.

These evaluations demonstrate that the ECCS design criterion of no clad melting is satisfied across the entire spectrum of possible liquid or steam line break sizes by at least two separate and independent systems and by two different modes of core cooling, even in the event of the loss of normal station auxiliary power.

6.3.3.3.10 Appendix K Criterion

The original ECCS design basis of no fuel clad melting was used to size ECCS equipment. In 1974, 10 CFR 50, Appendix K, "ECCS Evaluation Models," was implemented reducing the allowed peak clad temperature to 2200°F.

The Dresden Appendix K analysis does not address the original design basis of fully redundant, diverse, low pressure ECCS systems. The analysis does prove, as required, that the integrated ECCS provides adequate core cooling for the design basis accident assuming a limiting single active failure (e.g., for LPCI injection valve failure, two core spray pumps provide adequate cooling; for diesel generator failure, one core spray and two LPCI pumps provide adequate cooling).

The LOCA Appendix K analysis cases envelope all remaining design basis events with a single failure (see Tables 6.3-21b and 6.3-21c).

Additional emergency core cooling capability exists from the feedwater-condensate systems in the more probable event that station auxiliary power is available.

6.3.3.4 Integrated System Operating Sequence

6.3.3.4.1 Design Basis Accident

Since the emergency core cooling system is composed of several subsystems that are designed to perform under specific conditions, the operating sequence must be described for alternate operating conditions.

With normal ac power available all systems are actuated and there is no preferential sequencing. However, when power is supplied by the diesel generators, the pump motor starting loads must be sequenced to prevent overloading each diesel. The design basis accident (complete severance of the largest coolant pipe) represents the most severe time/load conditions. Therefore, the event sequence shown in Tables 6.3-13c and 6.3-13d are based on this accident condition.

Upon receipt of the accident initiation signal, the LPCI subsystem is initiated first to start the flooding effort as soon as possible (see Section 6.3.2.2 for the description of operation). Because the LPCI admission valves are still closed, the LPCI pumps are started with minimum bypass flow to prevent a dead headed pump condition.

Both core spray subsystems are timed to start after sufficient time has been allowed for starting all LPCI pumps. The core spray subsystems are started with 3% bypass flow to minimize the diesel starting load. The detailed operating sequence for the core spray subsystem is discussed in Section 6.3.2.1.

The LPCI injection valve and each core spray system's injection valves open as soon as the reactor low pressure permissive is cleared. See Section 6.3.3.3.2 for a complete description of the long term cooling requirements.

After 10 minutes, at least one LPCI pump and two containment cooling service water pumps are needed for suppression pool cooling. One LPCI pump or one core spray pump is adequate to maintain two-thirds core coverage, and at least one LPCI pump must operate to provide containment spray cooling. The loads on the diesel under these conditions can be carried indefinitely. Diesel generator 2/3 can then be made available to the non-accident unit.

This page is intentionally blank.

This page is intentionally blank.

6.3.3.4.3 Net Positive Suction Head for ECCS Pumps

The evaluation of post LOCA NPSH for core spray and LPCI pumps was divided into two portions:

1. Short Term (less than 600 seconds - no operator action credited-vessel injection phase)

2. Long Term (greater than 600 seconds - operator action credited-containment cooling phase)

It should be noted that the 600 second mark for operator action was established per UFSAR Sections 6.2.1.3.2.2 as the time in which credit for manual initiation of containment cooling can be taken.

6.3.3.4.3.1 CS/LPCI Pump Post-LOCA Short Term Evaluation

A calculation was performed to evaluate LPCI and core spray NPSH requirements in the short-term post-DBA LOCA. Short-term is considered the time period from initiation of the design basis LOCA until 10 minutes post-accident when operator action is credited.

The most limiting single failures (SFs) relating to Peak Clad temperature (PCT) were considered:

1. SF-LPCI: Failure of a LPCI injection valve

   This case results in two (2) core spray pumps injecting at maximum flow with four (4) LPCI pumps running on minimum flow only.

2. SF-DG: Loss of Diesel Generator

   This case results in two (2) LPCI pumps and one (1) core spray pump injecting at maximum flow.

The most limiting failure with regards to LPCI/CS pump NPSH, however, is failure of the LPCI Loop Select Logic (SF-LSL). This scenario involves the LPCI pumps in the short term injecting into a broken reactor recirculation loop and is discussed in detail in GE SIL 151. From a PCT perspective, this case is identical to the SF-LPCI case since the net result of each scenario is two core spray pumps injecting into the core with no contribution from the LPCI pumps. SF-LSL is the NPSH limiting scenario due to the LPCI/CS pumps operating at the highest achievable flow rates, resulting in the maximum pump suction losses and NPSH requirements. Additionally, the LPCI water escaping to the containment results in reduced containment and suppression pool pressures, which limit the available NPSH, see Section 6.2.1.3.3. Both the SF-LSL and SF-DG single failure cases were evaluated in the calculation. The SF-LPCI case is bounded by the SF-LSL case.

The calculations use the following inputs:

1. Maximum LPCI and core spray pump flow conditions (un-throttled system, reactor pressure at 0 psid), maximizing suction friction losses and NPSH required.

    a. Maximum LPCI and core spray pump flows-case SF-LSL

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	3-Pump Maximum Injection Flow:	16,750 gpm [5,610/11,140]
LPCI	4-Pump Maximum Injection Flow:	20,600 gpm

b. Maximum LPCI and core spray pump flows-case SF-DG

CS	1-Pump Maximum Injection Flow:	5800 gpm
LPCI	2-Pump Maximum Injection Flow:	11,600 gpm

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. To account for strainer plugging, each of the four torus strainers is assumed partially plugged.

4. Containment conditions used in the analysis are given in UFSAR Section 6.2.1.3.3 which minimize the NPSH available.

5. Initial suppression pool temperature is 95°F which is the maximum allowable pool temperature under normal operating conditions. This value is used as the initial pool temperature to maximize pool peak temperature, and is used as a minimum temperature during the LOCA to maximize piping friction losses (maximum viscosity).

6. The minimum suppression pool level elevation using a maximum drawdown of 2.1 ft. is 491'5", (491.4 ft). LPCI and core spray pump centerline elevation is 478.1 ft.

7. The suppression pool strainers have a head loss of 5.8 ft. @ 10,000 gpm, for each of the four partially plugged strainers.

8. NPSHR values at various LPCI/CS pump flows are taken from the vendor pump curves.

The minimum suppression pool pressure required to meet LPCI/CS pump NPSH requirements was determined for both the SF-LSL and SF-DG single failure cases. The minimum pool pressure required was compared to the minimum pool pressure available post-LOCA for two cases:

- Case 6a2 with 60% thermal mixing used for SF-LSL containment conditions.

- Case 2a1 with 100% thermal mixing used for the SF-DG containment conditions.

If the pressure available is greater than the pressure required, then adequate NPSH exists. If the available pressure is less than the pressure required, then the potential exists for the pumps to cavitate, resulting in reduced flows.

For the SF-LSL case at 2957 MWt, no cavitation is expected to occur for the first 290 seconds post-LOCA. Since PCT at this power level occurs prior to 240 seconds, the CS pumps will deliver adequate flow to ensure no impact on PCT. After 290 seconds, the LPCI and CS pumps may cavitate, resulting in reduced flows. The CS pump NPSH deficit reaches a maximum of 4.63 feet at 600 seconds, with a reduction in CS pump flow to about 11,000 gpm (5500 gpm per pump). This represents the minimum expected flow from the core spray pump for the 290 to 600 second interval.

As stated above, a potential exists for the LPCI and CS pumps to cavitate PCT is reached post-LOCA. However, as part of the original design of the plant, the pump vendor performed a cavitation test on a LPCI pump (a Quad Cities (RHR) pump was actually used). The Cavitation Test Report for Bingham 12x14x14x1/2 CVDS pump demonstrated no evidence of any damage to the pump components from cavitation with up to one hour of operation at the cavitating condition.

This analysis was reviewed with respect to the core spray pump and the results determined to be applicable. The rationale for this determination is the following:

- Core spray and LPCI are the same make and model pump (only impeller diameter is different).

- LPCI and core spray utilize the same impeller pattern, and therefore the same overall characteristics.

- All LPCI and core spray pumps have tested NPSHR curves that are essentially identical (within 1%).

For the SF-DG case at 2957 MWt, adequate suppression pool pressure is available to satisfy LPCI/CS pump NPSH requirements for the first 290 seconds. That is, no LPCI/CS pump cavitation will occur, nor will any flow reduction occur.

Therefore, under the most limiting single failures, the ECCS will still perform its function in the short term with no credit for operator action.

9x9-2 and ATRIUM-9B fuel types. The PCT for the SF-LPCIIV case occurs by about 240 seconds at 2957 MWT operation for the GE14, 9x9-2 and ATRIUM-9B fuel types.

- For the SF-DG case, a two-pump LPCI flow of at least 9000 gpm. and a single core spray pump flow of at least 5650 gpm are required for PCT considerations at 2527 MWT operation for the 9x9-2 and ATRIUM-9B fuel types. Core spray pump flaw of 5300 gpm for the SF-DG case is required for PCT considerations at 2957 MWT operation for the GE14, 9x9-2 and ATRIUM-9B fuel types.
- Only a constant nominal total pump flow of 9000 gpm is required to achieve 2/3 core reflood in less than 5 minutes at 2527 MWT operation for the 9x9-2 and ATRIUM-9B fuel types.

Therefore, under the most limiting single failures, the ECCS will still perform its function in the short term with no credit for operator action.

6.3.3.4.3.2 CS/LPCI Pump Post-LOCA Long Term Evaluation

The evaluation examined the net positive suction head (NPSH) available to the Dresden LPCI and core spray (CS) pumps after the first 600 seconds following a DBA LOCA for several pump combinations.

If the suppression pool pressure available is greater than the pressure required for adequate NPSH to the LPCI and CS pumps, then these pumps have adequate NPSH for operation. If the suppression pool pressure available is less than the pressure required by the pumps, then there is inadequate NPSH for operation and there is a potential for pump cavitation. In these situations, LPCI pump flows were reduced below nominal values and new cases were run to establish the ability of the operator to throttle the pumps to an acceptable condition.

A spectrum of pump combinations was explored to determine the bounding NPSH case for the LPCI and core spray pumps. It will be shown that the 4 LPCI/2 CS pump case is bounding for NPSH.

The calculation uses the following inputs:

1. Various LPCI and core spray pump flow conditions are evaluated (See Table 6.3-18).

2. Increased clean, commercial steel suction piping friction losses by 15% to account for potential aging effects, thus maximizing suction losses.

3. It is assumed that at 10 minutes into the accident, operator action will be taken to ensure that the LPCI/CS pumps have been throttled to their rated flows (5000 and 4500 gpm respectively). Therefore, the pumps are at their rated flows at the time of peak suppression pool temperature (~33,000 seconds at 2957 MWt).

4. To account for strainer plugging, each of the four torus strainers is assumed partially plugged.

5. Initial suppression pool temperature is 95 °F. This is the maximum allowable suppression pool temperature under normal operating conditions.

6. The containment pressure and pressure responses provided in UFSAR Section 6.2.1.3.3 are used.

7. The minimum torus level elevation with a maximum drawdown of 2.1 ft is 491.4 ft. At the time of peak suppression pool temperature, a recovery of 1.1 ft occurs, resulting in a net drawdown of 1 ft.

8. The torus strainers have a clean head loss of 1.97 ft @ 10,000 gpm for each of the four partially plugged strainers.

9. LPCI and core spray pump centerline elevation is 478.1 ft.

The calculation determined the minimum suppression pool pressure required to meet pump NPSH requirements for several ECCS pump combinations. The calculation shows that potential exists for the LPCI and Core Spray pumps to cavitate at rated flows as shown in Table 6.3-18. For these cases, throttling of pumps to below rated flows may be required to ensure NPSH requirements are met. A minimum of 5000 gpm total LPCI flow is required for containment cooling. Table 6.3-18 provides NPSH margin for throttled cases.

The containment analysis used to determine minimum containment pressures was performed with containment sprays on from 600 seconds through accident termination. In order to more closely tie containment pressure to NPSH requirements, the Emergency Operating Procedures provide guidance to the operators to terminate sprays when required to ensure adequate NPSH for the LPCI and core spray pumps. NPSH calculations show that containment overpressure is required for no cavitation during long term post-LOCA conditions with LPCI and core spray pumps operating at rated flows. Operating procedures provide directions for operating sprays so that containment pressure will be maintained within the pressure required for adequate NPSH.

Operators have been trained to recognize cavitation conditions and to protect their equipment by throttling flow if evidence of cavitation should occur due to inadequate NPSH. The control room has indication of both discharge pressure and flow on each division of core spray and LPCI. The Emergency Operating Procedures (EOPs) also provided guidance to maintain adequate NPSH for the core spray and LPCI pumps. The NPSH curves provided in the EOPs utilize torus bulk temperature and torus bottom pressure to allow the operator to determine maximum pump or system flow with adequate NPSH. These curves are utilized as long as the core is adequately flooded.

6.3.3.4.3.3 <u>NPSH Margin</u>

Figures 6.3-80 and 6.3-80a give a graphical representation of the minimum required containment pressure to meet NPSH requirements for both LPCI and core spray pumps. The chart covers both the short-term (≤ 600 seconds) and long-term (> 600 seconds) periods.

At runout flows, the core spray pumps have the potential to cavitate for a short period of time (after PCT is reached) during the ≤ 600 second period. This is acceptable per the discussion in UFSAR Section 6.3.3.4.3.1. Figures 6.3-80 and 6.3-80a also show the ability to throttle the core spray and LPCI pumps to an acceptable long term operating condition as discussed in UFSAR Section 6.3.3.4.3.2.

6.3.3.4.3.4 Containment Overpressure

Adequate net positive suction head for the low pressure ECCS pumps is credited as follows:

This is graphically shown in Figures 6.3-83, 6.3-83a, 6.3-84, and 6.3-84a.

Unit 2 (2957 MW_t) Time Period (seconds)	Containment Overpressure (psig)
0 – 290	9.5
291 – 5,000	4.8
5,001 to 30,000	6.6
30,001 – 40,000	6.0
40,001 – 45,500	5.4
45,501 to 52,500	4.9
52,501 to 60,500	4.4
60,501 to 70,000	3.8
70,001 to 84,000	3.2
84,001 to 104,000	2.5
104,001 to 136,000	1.8
136,001 to accident termination	1.1

This is graphically shown in Figures 6.3-83, 6.3-83a, 6.3-84, and 6.3-84a.

During a LOCA, the operator's concern will be restoration of the vessel water level. The LPCI flow will be among the parameters closely monitored in the minutes immediately after the LOCA. The operator has several motor-operated valves available to him in the main control room to adjust flowrates or even isolate flow paths. It is, therefore, concluded that operator observation and response to flow conditions will be completed shortly after the LOCA.

Because of the falling head characteristics of these pumps, the brake horsepower requirements are nearly constant from 4000 to 6000 gal/min. It is thus concluded that no overload will occur for either the LPCI pumps or for the emergency diesel generators powering them in the event of a loss of offsite power.

It is, therefore, concluded that for the conditions evaluated, no threat to the long-term cooling capability exists.

Hence, adequate NPSH is ensured at all times to allow continuous operation of the LPCI and core spray pumps.

6.3.3.4.3.5 HPCI NPSH

The HPCI subsystem takes suction from the condensate storage tank which remains cold throughout the plant cooldown so that the NPSH available is unaffected by torus heatup. If suction were taken from the torus, design calculations demonstrate that NPSH available exceeds NPSH required with torus water temperature at 140F and the HPCI flowrate at 5600gpm.

6.3.4 Tests and Inspections

6.3.4.1 Core Spray Subsystem

Provisions have been designed into the core spray subsystem to test the performance of its various components. These provisions and tests are summarized as follows:

A. Instrumentation

- Operational test of entire subsystem.
- Periodic subsystem tests using test lines.

B. Valves

- Preoperational test of entire subsystem.
- Periodic subsystem tests using test lines.
- Test leak-off lines between isolation valves.
- Test drainline on pump side of outboard isolation valves.
- Motor-operated valves can be exercised independently.

C. Pumps

- Preoperational test of entire subsystem.
- Periodic subsystem tests using test lines.
- Monitoring pump seal leakage.

D. Spray Sparger

- Preoperational test of entire subsystem.

E. Spray Nozzles

- Pre-operational test of entire subsystem.

F. Relief Valves

- Can be removed and tested for test point.

G. Screens

- Preoperational test of entire subsystem.
- Periodic subsystem tests using test lines.
- Pressure indicator on pump suction during above tests.

Each core spray subsystem may be tested individually during reactor operation as follows:

A. The pump of the loop under test may be started by its manual control switch. The test bypass valve is opened to allow the pump to be tested at full flow. Flow and pressure instrumentation is observed for correct response and the subsystem outside the drywell may be checked for leaks.

B. The injection valves may be tested independently of the pump and flow test as follows:

1. The normally open maintenance valve upstream of the normally closed injection valve is closed by the control switch. Limit switches on the maintenance valve act as a permissive to open the injection valve which may then be exercised (opened and closed) by manual actuation of the control switch.

2. At the end of the test, with the startup valve fully closed, the maintenance valve must be opened.

In the event that a reactor low-low water level and reactor low pressure actuation signal, or a high drywell pressure actuation signal occurs during a loop test, the loop not under test will start automatically. The loop being tested will return to the automatic mode. The valves will reposition as required for automatic operation. The pump will stay running (unless a loss of power occurs).

The pressure differential between the system piping inside the vessel and an internal reference pressure is monitored during power operation. Changes in these pressure readings provide indication of loss of integrity of piping within the vessel. In addition, pipes, pumps, valves, and other working components outside of the primary containment can be visually inspected at any time.

The check-isolation valves are tested per ASME Section XI during a full flow test of the system while the reactor is in cold shutdown.

All necessary experimental programs to confirm the performance of the core spray subsystem were performed and are described in Section 6.3.3.1.1.

6.3.4.2 Low Pressure Coolant Injection Subsystem

To assure that the LPCI subsystem will function properly if required, specific provisions have been made for testing the operability and performance of the several components of the subsystem. Testing is performed periodically. In addition, surveillance features provide continuous monitoring of the integrity of vital portions of the subsystem.

A design flow functional test of the LPCI pumps is performed for each combination of three pumps during normal plant operation by taking suction from the suppression pool and discharging through the test lines back to the suppression pool. The inboard injection valve to the reactor recirculation loops remains closed during this test and reactor operation is undisturbed. An operational test of the LPCI injection valves is performed by shutting the upstream injection valve; opening and then closing the downstream injection valve; and after the downstream valve has been satisfactorily tested, the upstream injection valve is reopened. The discharge valves to the containment spray headers are checked by operating the upstream and downstream valves individually. All of these valves can be actuated from the control room using remote manual switches. Control system design provides automatic return from test to operating mode if LPCI initiation is required during testing.

Testing of LPCI subsystem sequencing is performed after online and the reactor is shut down.

Periodic inspection and maintenance of the LPCI pumps, pump motors, and heat exchangers is carried out in accordance with the manufacturer's instructions.

6.3.4.3 High Pressure Coolant Injection Subsystem

To ensure that the HPCI subsystem will function properly if it is needed, specific provisions have been made for testing the operability and performance of the various parts of the subsystem. This testing can be done at a frequency that will ensure availability of the subsystem. In addition, surveillance features will provide continuous monitoring of vital portions of the HPCI subsystem.

The performance of the pump assembly was certified by the vendor over its operating range based on the following test data:

A. Head/flow tests of the booster pump running at 2155 rpm;

B. NPSH requirement of the booster pump running at 2155 rpm determined at 6500 gal/min and 5000 gal/min;

C. Head/flow tests of the main pump running at 3584 rpm;

D. NPSH requirement of the main pump running at 3584 rpm, determined at 5000 gal/min; and

E. Using the above test data and the pump hydraulic relationships of speed, flow, head, and horsepower, the certified performance of the HPCI pump assembly was developed (i.e., NPSH, developed head, and horsepower versus speed).

Figures 6.3-81 and 6.3-82 show sample performance curves for the HPCI pump and turbine. The actual test performance of the pumps assembly equaled or bettered the predicted performance.

The following paragraphs detail the testing and surveillance that can be accomplished during the different modes of operation of the plant.

6.3.4.3.1 Prior to Full Power Operation (Initial Unit Startup)

A. When sufficient steam is available from the reactor to drive the HPCI turbine at its rated speed, the subsystem can be activated to assure operation of all components at this rated condition.

B. Suction can first be taken from the condensate storage tank and pumped through the complete HPCI subsystem to the reactor. Suction can then be taken from the suppression chamber, pumped through the subsystem, and returned to the suppression chamber by way of the test return line.

C. Flow, bearing temperatures, and differential pressure measurements will be taken during this power test to verify design conditions and to establish reference points for comparison to data from subsequent tests.

D. Taking suction from the suppression chamber during the test at rated conditions verifies that water is available as needed.

6.3.4.3.2 Unit Operating or at Hot Standby

A test of the subsystem up to the isolation valve can be conducted with steam from the reactor vessel. The steam admission valve is opened, driving the turbine pump unit at its rated output. The valves from the suppression chamber and to the feedwater line remain closed and water is pumped from the condensate storage tank, through the subsystem, and returned to the condensate storage tank by way of the test line.

6.3.4.3.3 System Testing

The pump may be tested at full flow at any time except when reactor water level is low.

Testing is accomplished as follows:

A. The pump suction valve from the condensate storage tank is opened (if shut) and the minimum flow bypass valve to the suppression pool is opened;

B. The turbine steam supply valve is opened with the remote manual switch to start the pump and establish minimum flow;

C. The test bypass valve is then opened to establish full rated flow from the pump through the bypass line to the condensate storage tank;

D. With the pump off and the maintenance block valve upstream of the pump discharge valve closed, the pump discharge valve may be tested by stroking the valve open and closed with the remote manual switch.

The HPCI check valve is tested by opening the equalizing line and then manually stroking the valve. The check valve is only testable when the unit is shutdown. Remote valve disc position indication is not used to verify valve stroke for the 2(3)-2301-7 check valves.

6.3.4.3.4 An Accident Signal Simultaneous with Test

In the event that an accident signal occurs while the HPCI subsystem is being tested, the subsystem is automatically restored to the automatic startup status and will begin operation.

6.3.4.4 Automatic Depressurization Subsystem

Testing of the ADS valves is described in Section 5.2.2. Operability testing of the ADS subsystem is discussed in Section 7.3.

6.3.5 References

1. Docket 50-219, Oyster Creek Unit 1, Amendment 10, Appendix A.

2. Topical Report APED-5458, General Electric Company.

3. Oyster Creek FSAR, Docket 50-219, Amendment 30.

4. Oyster Creek FSAR, Docket 50-219, Amendment 34, Question 6, Section 1.1.

5. Oyster Creek UFSAR Amendment 33, Appendix A.

6. Topical Report APED-5750, "Design and Performance of General Electric Boiling Water Reactor Main Steam Isolation Valves," Sections 3.2.1, 3.2.6, and 5.4, General Electric Company.

7. Browns Ferry FSAR Amendment 6, Page C-8-3, Rotor Burst Analysis by John Corr.

8. Deleted.

9. Deleted.

10. Deleted.

11. N. Zuber and J. Findley, "Average Volumetric Concentration in Two-Phase Flow Systems," Transactions of ASME Journal of Heat Transfer, SER. C, 87, 453-468, 1965.

12. Ishii, "One-Dimensional Drift Flux Model and Constitutive Equations for Relative Motion between Phases in Various Two-Phase Flow Regimes," ANL-77-47.

13. M. Ishii, T.C. Cahawla, and N. Zuber, "Constitutive Equation for Vapor Drift Velocity in Two-Phase Annular Flow," AICHE Journal, Volume 22, No. 2, March 1976.

14. NUREG/OR-0063, LS-7279-MS, Volume 1, "TRACP-P1: An Advanced Best Estimate Computer Program for PWR LOCA Analysis, Volume 1: Methods, Models, User Information, and Programming Details," Los Alamos Scientific Laboratory, June 1978.

15. Miroplosky, Z.L. et al., Volume III, International Heat Transfer Conference, Japan, Cs 1.7, 1974.

16. Connective Boiling and Condensation, John G. Collier, McGraw-Hill Book Company, 1972.

17. NUREG-75/056, "WREM: Water Reactor Evaluation Model (Revision 1)," May 1975.

18. Kreith, F., Principles of Heat Transfer, International Textbook Company, Fourth Printing, 1962, p. 306.

19. Bromley, L.A., Heat Transfer in Stable Film Boiling, Chemical Engineering Progress 46, pp. 22-227, 1950.

20. Sun, K.H., and Fernandez, "Countercurrent Flow Limitation Correlation for BWR Bundles during LOCA," ANS Transaction, Vol. 27, pp. 605-606, 1977.

21. Sun, K.H., "Flooding Correlations for BWR Bundle Upper Tie Plates and Bottom Side-Entry Orifices," Proceeding of Multi-Phase Flow and Heat Transfer Symposium, Miami Beach, April 1979.

22. G. B. Wallis, "One-Dimensional Two-Phase Flow," McGraw-Hill, Inc., New York, 1969.

23. Anderson, J.G.M., and Hensen, P., "Two-Dimensional Heat Conduction in Rewetting Phenomena," Report No. NORHAV-D-6, AEC Research Establishment Riso, Denmark, June 1974.

24. "Analytical Model for Bottom Reflooding Heat Transfer in Light Water Reactors (The UCFLOOD Code)," EPRI NP-756, August 1978.

25. Holmes, J.P., Heat Transfer, McGraw-Hill, 1976.

26. Siegel, Robert and Howell, John, R., "Thermal Radiation Heat Transfer," McGraw-Hill, 1972.

27. Deleted.

28. Deleted.

29. Deleted.

30. Deleted.

31. "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10 CFR 50 Appendix K," NEDO-20566, January 1976.

32. "Cladding Swelling and Rupture Models for LOCA Analysis," NUREG-0630, April 1980.

33. Topical Report APED-5608, General Electric Company.

34. Oyster Creek FSAR, Docket 50-219, Amendment 5.

35. Moody, F. J., "Maximum Flowrate of a Single Component Two-Phase Mixture," Journal of Heat Transfer, ASME Series C, Vol. 87, February 1965.

36. Moody, F.J., "Liquid/Vapor Action in a Vessel During Blowdown," APED-5177, 1966.

37. Zuber and Hench, "Steady-State and Transient Void Fraction of Bubbling Subsystems and Their Operating Limits, Part 1, Steady Station Operation," General Electric Report 62GL100, 1962.

38. Haberman and Morton, "An Experimental Investigation of the Drag and Shape of Air Bubbles Rising in Various Liquids," Navy Dept., David Taylor Model Basic, Report 802, September 1953.

39. Shapiro, "Compressible Fluid Flow", Vol. I, p. 17.

40. Moody, F.J., "Maximum Two Phase Vessel Blowdown from Pipes," ASME Paper No. 65-WA/HT-1.

41. FSAR Amendment 10/11, Question I.A.1, Appendix C.

42. Ianni, F.W.; Fritz, J.R.; and Law, D.D., "Design and Operating Experiences of the ESADA Vallecitos Experimental Superheat Reactor (EVESR)," APED-4784, 1965.

43. "Nuclear Safety Quarterly Report, February, March, April, 1968, for Nuclear Safety Branch of USAEC Division of Reactor Development and Technology," BNWL-885, October 1968.

44. Moody, F.J., "Maximum Two-Phase Vessel Blowdown from Pipes," APED-4827, 1965.

45. Moody, F.J., "Perfect Nozzle Blowdown Study," APED-4398, 1963.

46. Moody, F.J., "An Analytical Model for Pressure Suppression," APED-4734, 1964.

47. "Preliminary Hazards Summary Report, Bodega Bay Atomic Park Unit No. 1," PG&E, December 28, 1962.

48. Robbins, C.H., "Tests of a Full Scale 1/48 Segment of the Humboldt Bay Pressure Suppression Containment," GEAP-3596, 1960.

49. Tong, L. S. "Transient CHF Prediction" Presented at ASME-AICHE Heat Transfer Conference, Philadelphia, August 1968.

50. General Electric BWR Thermal Analysis Basis (GETAB): Data, Correlation and Design Application, NEDO-10958-A, January 1977.

51. "Loss-of-Coolant Accident Analysis Report for Duane Arnold Energy Center (Lead Plant)," NEDO-21082-02-1A, Appendix A, Revision 1, July 1977.

52. Deleted.

53. Deleted.

54. J.F. Wilson, et.al., "The Velocity of Rising Steam in a Bubbling Two Phase Mixture", ANS Transactions, Vol. 5, No. 1, p. 151, 1962.

55. APED 5529, Core Spray and Core Flooding Heat Transfer Effectiveness in a Full Scale Boiling Water Reactor Bundle.

56. Docket 50-249, Dresden Unit 3, Amendment 5, Appendix IIE.

57. Reliability Analysis of Nuclear Power Plant Protective system, B.J. Garrick et al., HN-190, May 1967.

58. Availability Analysis, A Useful Tool for Improving system Designs, I.M. Jacobs and A.H. Klose, APED-5496, Class II, April 1967.

59. Failure Rate Data Handbook, Bureau of Naval Weapons, U.S. Naval Ordnance Laboratory, Corona, California.

60. Apollo Reliability Prediction and Evaluation Guidelines, National Aeronautics and Space Administration; ASK-R-05-64-1 (R-11).

61. Reliability Application and Analysis Guide, D.R. Earles.

62. UKAEC Atomic Power Plant Failure Rate Data (Received from Rodney Fordham, UKAEC, England).

63. NUREG 0823, Section 4.2.3.1, February 1983 SEP Topic VI-10B Shared Engineering Safety Features/Sharing of DC systems.

64. Deleted.

65. Deleted.

66. Deleted.

67. Deleted.

68. Deleted.

69. Deleted.

70. “SAFER/GESTR-LOCA Loss of Coolant Accident Analysis for Dresden Nuclear Station 2 and 3 and Quad Cities Nuclear Station Units 1 and 2,” NEDC-32990P, Revision 2, September 2003.

71. “PDLB OPL-4, Rev. 3 for Approval,” Exelon Letter NFM:BND-00-118, December 7, 2000.

72. “GE Position Summary Regarding Long-Term Post-LOCA Adequate Core (Cooling Requirements,” GENE Letter OGOO-0382-01 (DRF-E22-00135-01), November 16, 2000.

73. Deleted.

74. “Dresden 2 and 3 Quad Cities 1 and 2 Equipment Out-Of-Service and Legacy Fuel Transient Analysis, “ GE-NE-J11-03912-00-01-R3, Revision 3, September 2005.

75. Deleted. Duplicate of 77.

76. General Electric Document NEDC-32962P, “Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate,” December 2000.

77. “Dresden and Quad Cities Evaluation of Extended Final Feedwater Temperature Reduction” GE-NE-A13-00487-00-01P, Revision 1, August 2002.

78. OPTIMA2-TR021DR-LOCA, “Dresden 2 & 3 LOCA Analysis for SVEA-96 Optima2 Fuel” Revision 5, October 2009.

79. Reference not used.

80. CENPD-300-P-A, Reference Safety Report for Boiling Water Reactor Reload Fuel, July 1996.

81. RPB 90-93-P-A, Boiling Water Reactor Emergency Core Cooling System Evaluation Model: Code Description and Qualification, October 1991.

82. RPB 90-94-P-A, Boiling Water Reactor Emergency Core Cooling System Evaluation Model: Code Sensitivity, October 1991.

83. CENPD-293-P-A, BWR ECCS Evaluation Model: Supplement 1 to Code Description and Qualification, July 1996.

84. WCAP-15682-P-A, Westinghouse BWR ECCS Evaluation Model: Supplement 2 to Code Description, Qualification and Application, April 2003.

85. WCAP-16078-P-A, Westinghouse BWR ECCS Evaluation Model: Supplement 3 to Code Description, Qualification and Application to SVEA-96 Optima2 Fuel, November 2004.

86. WCAP-15942-P-A, Fuel Assembly Mechanical Design Methodology for Boiling Water Reactors Supplement 1 to CENPD-287, April 2006.

87. “Boiling Water Reactor Emergency Core Cooling System Evaluation Model: Code Sensitivity for SVEA-96 Fuel,” CENPD-283-P-A, July 1996.

88. RP 87-04/SVEA 87-09, “SVEA SPRAY COOLING TEST, Test Results and Evaluation,” March 1987.

Table 6.3-1

EMERGENCY CORE COOLING SYSTEM SUMMARY[5]

Function	Number of Operating Pumps	Design Coolant Flow (gal/min)	Delivery Pressure Range	Required Electrical Power	Additional Backup Systems
Core Spray[1]	1	4500 at 90 psid[4]	<325 psid	Normal auxiliary power or emergency diesel generator	Second core spray subsystem and LPCI subsystem
LPCI[1]	3	8000 at 200 psid[4] 14,500 at 20 psid[4]	<275 psid	Normal auxiliary power or emergency diesel generator	Core spray subsystems and fourth LPCI pump
HPCI[2]	1	5600 constant	1135 to 165 psia	DC battery system for control and AC power for room cooler fan[3]	Automatic depressurization plus core spray and LPCI

Notes:

1. Automatic startup of the core spray and LPCI systems is initiated by: reactor low-low water level and reactor low pressure, drywell high pressure, or reactor low-low water level continuing for 8.5 minutes.
2. Automatic startup of the HPCI system is initiated by: reactor low-low water level, or drywell high pressure.
3. Reactor steam-driven pump.
4. Differential pressure between the reactor and primary containment.
5. This information is historical and is not needed to support the current design basis.

Table 6.3-2

SUMMARY OF OPERATING MODES OF EMERGENCY CORE COOLING SYSTEMS[2]

A. Loss of Normal Auxiliary Power Alternate systems:[1]

Isolation condenser system and ADS	or	HPCI subsystem or ADS plus core spray subsystem and LPCI subsystem

B. Small Line Break Only (no loss of normal auxiliary power) Alternate systems:

Feedwater system	or	HPCI subsystem or ADS plus core spray subsystem and LPCI subsystem

C. Large Line Break (no loss of normal auxiliary power) Alternate systems:

Two core spray subsystems	or	One core spray subsystem and one LPCI loop (two pumps)

D. Small Line Break Plus Loss of Normal Auxiliary Power (standby diesel available) Alternate systems:

HPCI subsystem	or	ADS plus core spray subsystem and LPCI subsystem

E. Large Line Break Plus Loss of Normal Auxiliary Power (standby diesel available) Alternate systems:

Two core spray subsystems	or	One core spray subsystem and one LPCI loop (two pumps)

F. Post-Accident Recovery Alternate system:

Standby coolant supply system

Sensible heat is removed from the primary containment by operation of the containment cooling subsystem.

Notes:

1. Available alternate systems, any one of which will provide the necessary cooling function.
2. This information is historical and is not needed to support the current design basis.

Table 6.3-3

CORE SPRAY EQUIPMENT SPECIFICATIONS

<u>PUMPS</u>	
Number	2
Type	single stage, vertical, centrifugal
Speed	3600 rpm
Seals	Mechanical
Drive	Electric motor
Power source	Normal auxiliary or standby diesel
Pump casing	Cast steel
Impeller	Stainless Steel
Shaft	Stainless steel
Flow	See Figure 6.3-4
Head	See Figure 6.3-4
Power	880 hp at rated conditions
NPSH (available)	See Section 6.3.3.4.3
<u>PUMP CASING CODES</u>	
Code	ASME Section III, Class C (1965)
Fracture toughness	The test requirements for the Core Spray Pumps were reviewed to NUREG-0577, October 1979, requirements as outlined in the NRC "Additional Guidance to NUREG-0577" letter from D.G. Eisenhut, Director, Division of Licensing NRC, dated May 20, 1980. Based on the material being in a heat-treated condition, the estimated value of the NDT temperature from Table 4.4 of NUREG-0577 is +- 75°F and, therefore, meets the criteria of Part I - Fracture Toughness as given in D.G. Eisenhut's letter.
Material	Carbon steel A 216, Grade WCB. Two copies per unit are provided.
Testing	Impact testing required per ASME Section III (1965). No records exist to verify such testing; however, the Bingham Pump Co. Engineering Data Sheet states, "Test bars are to be heat-treated in the same furnace charge through the same heat-treated cycle as the parts which they represent." This would indicate that impact testing was performed and did meet the code requirements permitting casing certification.

Table 6.3-3 (Continued)

CORE SPRAY EQUIPMENT SPECIFICATIONS

SPRAY HEADERS	
Number	2
Number of flow tubes	65 per header at alternating pattern
Number of nozzles	65 per header at alternating pattern
Type of nozzles	1-inch fulljet – stainless steel
PIPING	
Code	USAS B31.1

Table 6.3-4b

GE LOCA ANALYSIS ECCS LOADING SEQUENCE FOR GE14, ATRIUM-9B AND 9X9-2 FUEL AT 2957 MWT

Sequence	Elapsed Time (sec)	Event	Condition
1	0.0	Design basis accident	1
2	0.0	High Drywell Pressure Occurs (assumed)	
3	1.0	Time to sense High Drywell Pressure Signal to start CS & LPCI and Unit 2(3) swing Diesel Generators	
4	17	Time from initiating signal to Diesel Generator at Rated Speed and Bus Powered (undervoltage relays reset, LPCI pumps A and C started, LPCI pumps B and D time delay started, CS pumps A and B time delay started)	
5	26.0	LPCI Pumps A and B started	
6	31.0	CS Pumps A and B started	
7	31.0	All LPCI Pumps at Rated Speed	
8	36.0	All CS Pumps at Rated Speed	

1. No reliance on external source of power is assumed consistent with Appendix K assumptions. See Reference 71 for details on the approach used to define the plant design and licensing basis time delays.

Table 6.3-4c

WESTINGHOUSE LOCA ANALYSIS ECCS LOADING SEQUENCE
FOR SVEA-96 OPTIMA2 FUEL AT 2957 MWt

Sequence	Elapsed Time (sec)	Event	Condition
1	0.0	Break / loss of offsite power occurs	1
2	16.0	Unit and swing diesel generators started and bus powered Core spray pumps A and B time delay starts Operate AC power valves	
3	31.2	Start core spray pumps A and B Core spray minimum flow valves start to open	
4	36.2	Spray pumps A and B at rated speed	2

1. Initiating accident is assumed to be a 100% DBA suction line break coincident with the loss of off site power. The limiting single failure is the failure of the LPCI injection valve to open.
2. Core spray pumps are assumed to reach full speed 5 seconds after they start.

Table 6.3-5

LPCI EQUIPMENT SPECIFICATIONS

<u>MAIN SYSTEM PUMPS</u>	
Number	4
Type	Single-stage, vertical, centrifugal
Seals	Mechanical
Drive	Electric motor
Power source	Normal auxiliary or emergency diesel
Speed	3600 rpm (Nameplate rating 3540 rpm)
Pump casing	Cast steel
Impeller	Stainless Steel
Shaft	Stainless steel
<u>PUMP CASING CODES</u>	
Code	ASME Section III, Class C (1965)
Fracture toughness	The test requirements for the LPCI pumps were reviewed to NUREG-0577, October 1979, requirements as outlined in the NRC "Additional Guidance to NUREG-0577" letter from D.G. Eisenhut, Director, Division of Licensing NRC, dated May 20, 1980. Based on the material being in a heat-treated condition, the estimated value of the NDT temperature from Table 4.4 of NUREG-0577 is +- 75^{o}F and, therefore, meets the criteria of Part I - Fracture Toughness as given in D.G. Eisenhut's letter.
Material	Carbon steel A 216, Grade WCG. Four casings per unit are provided.
Testing	Impact testing required per ASME Section III (1965). No records exist to verify such testing. However, the Bingham Pump Co. Engineering Data sheet states, "Test bars are to be heat-treated in the same furnace charge through the same heat-treated cycle as the parts which they represent." This would indicate that impact testing was performed and did meet the code requirements permitting casing certification. The manufacturer serial numbers for the eight LPCI pumps (four per unit) are 260811 through 260818.

Table 6.3-5 (continued)

LPCI EQUIPMENT SPECIFICATIONS

Because of pump-unique piping configurations, the performance characteristics are different for each LPCI pump and combination of pumps. Therefore, the following information is a range of expected values based on current calculations.

FOUR PUMPS RUNNING		
	Minimum	Maximum
Flow at 0 psi Reactor Pressure	18,000 gpm	20,300 gpm
Flow at 20 psi Reactor Pressure	17,500 gpm	N/A
TWO PUMPS RUNNING		
	Minimum	Maximum
Flow at 0 psi Reactor Pressure	11,000 gpm	11,800 gpm
Flow at 20 psi Reactor Pressure	10,600 gpm	N/A
ONE PUMP RUNNING		
	Minimum	Maximum
Flow at 0 psi Reactor Pressure	6,000 gpm	6,100 gpm
Flow at 20 psi Reactor Pressure	5,800 gpm	N/A
	Minimum	Maximum
Head at 6,000 GPM	126 ft	173 ft

For the amount of flow credited in the accident analyses, refer to Table 6.3-20, Detailed information on the NPSH of the LPCI pumps may be found in Section 6.3.4.3.

Table 6.3-6

LOCA ANALYSIS AT 2527 MWT –
MAXIMUM EXPECTED JET PUMP LEAKAGE RATE DURING LPCI OPERATION FOR DESIGN BREAK
(gal/min)

This table has been intentionally deleted.

Table 6.3-7

HPCI EQUIPMENT SPECIFICATIONS

<u>TURBINE</u>	
Steam pressure inlet	1125 to 155 psia
Exhaust (maximum)	65 psia
Steam Temperature	558°F to 360°F
Speed	4000 to 2000 rpm(2)
Power	5000 to 1000 hp(2)
Number of stages	2
Emergency starting	25 seconds
Steam flow	145,000 to 102,500 lb/hr
<u>PUMP</u>	
Number	1 main, 1 booster
Type (main)	multi-stage, horizontal, centrifugal
(booster)	single-stage, horizontal, centrifugal, gear-driven
Discharge pressure	1135 to 165 psia
Flow	5600 gal/min constant
NPSH (minimum)	25 ft
<u>PUMP CASING CODES</u>	
Code	ASME Section III, Class C (1965) per GE Pump Data Sheet
Fracture toughness	The test requirements for the core spray, LPCI, and HPCI Pumps were reviewed to NUREG-0577, October 1979, requirements as outlined in the NRC "Additional Guidance to NUREG-0577" letter from D.G. Eisenhut, Director, Division of Licensing NRC, dated May 20, 1980. Based on the material being in a heat-treated condition the estimated value of the NDT temperature from Table 4.4 of NUREG-0577 is +- 75°F and therefore meets the criteria of Part I - Fracture Toughness as given in D.G. Eisenhut's letter.
Material	Carbon steel A 216, Grade WCB. Material data sheets show the tensile and chemical properties of the pump casings. The Dresden Unit 2 heat numbers are 5744 and 5738. Two casings per unit are provided.

Table 6.3-7 (Continued)

HPCI EQUIPMENT SPECIFICATIONS

PIPING, FITTINGS, AND VALVES	
Material	Carbon steel, A106, Grade B
Testing	System is exempted from impact testing per the current ASME Section III, Article NC 2311-a9 for Class 2 components, because all piping over 6 inches in diameter and 5/8-inch wall thickness is steam piping with lowest service temperatures exceeding 150°F.
Control Power	250/125 Vdc.[1]

Note:

1. See reference 6.3.5-63.
2. Although the turbine was tested by the manufacturer down to 2000 rpm/1000 hp, per GEK-15545 as installed the HPCI turbine speed and power low end ranges are limited by the MGU low speed stop (LSS) of 2250 rpm, which corresponds to a power range low limit of 1350 hp.

Table 6.3-8

TOTAL PRESSURES DURING RECIRCULATION LINE BREAK[1]
(psia)

Vessel Region	Time (seconds) 0	4	7
Lower Plenum	1045	997	976
Core	1030	993	974
Upper Plenum	1022	990	973
Downcomer	1015	987	973
Steam Dome	1010	985	973

[1] Notes: These results are historical and not necessarily applicable to the current fuel cycle.

Table 6.3-9

SYMBOLS AND SUBSCRIPTS USED FOR HISTORICAL BLOWDOWN ANALYSIS AT 2527 MWt
(Section 6.3.3.2.2.5.1)

Major Symbols	
A	Area
G	Mass flowrate per unit area
H	Vessel height
h	Specific enthalpy
M	Mass
P	Pressure
s	Specific entropy
t	Time
U	Bubble rise velocity relative to liquid
v	Specific volume
W	Flowrate
X	Homogeneous quality
$X_{\{F\}}$	Flowing quality
$Y_{\{L\}}$	Mixture level

Subscripts	
B	Break
C	Critical flow
f	Saturated liquid
fg	Vaporization
g	Saturated vapor
o	Stagnation, or initial value

Table 6.3-10

IMPORTANT EXPERIMENTAL QUANTITIES

	Bodega 30	Humbolt 17	CSE, B-15
Vessel Volume, ft^3	80	55	150
Initial Pressure, psia	1250	1250	2000[1]
Vessel Height H, ft	20	31.4	15
Vessel Area A_v, ft^2	3.97	1.75	9.36
Break Area A_B, ft^2	0.0573	0.044	0.0643
Initial Fluid Mass, lb	2420	1795	6700
Initial Level Fraction $\frac{Y_{Lo}}{H}$ 59	0.685	0.735	1.0
Equivalent Break Area $A_B^{(1)}$ 60	0.053	0.0388	0.0446
Value for $\frac{A_B^{(1)}}{A_V}$, s/ft 61	0.0134	0.0222	0.00477
The term $\frac{1}{G_o U_f}$, s/ft 62	0.00513	0.00513	0.00366

Notes:

1. Approximately.

Table 6.3-11

Deleted

Table 6.3-12e

SAFER/GESTR-LOCA LICENSING RESULTS
FOR GE14, 9x9-2 AND ATRIUM-9B AT 2957 MWt

	Parameter	SAFER/GESTR-LOCA RESULTS			LICENSING ACCEPTANCE CRITERIA
1.	Limiting Break	DBA (Recirculation Suction Line)			
2.	Limiting ECCS Failure	Diesel Generator			
3.	Fuel Type	GE14	9x9-2	ATRIUM 9B(1)	
4.	Peak Cladding Temperature (Licensing Basis)	<2110°F	(1)	<2060°F	<2200°F
5.	Estimated Upper Bound PCT (95% Probability PCT)	<1570°F	(1)	<1600°F	<1600°F
6.	Maximum Local Oxidation	<6%	(1)	<5%	<17%
7.	Core-Wide Metal-Water Reaction	<0.1%	(1)	<0.1%	<1%
8.	Coolable Geometry	Items 4 & 6			PCT<2200°F and Local Oxidation <17%
9.	Long Term Cooling	Core reflooded or One core spray operating			Long-term decay heat removal

NOTES: (1) The ATRIUM-9B fuel results are bounding for the 9x9-2 fuel type with the restriction that the PLHGR and MAPLHGR for 9x9-2 do not exceed 10.84 kw/ft.

Table 6.3-12f
DRESDEN LOCA LICENSING RESULTS
WITH SVEA-96 OPTIMA2 FUEL AT 2957 MWt

	Parameter	Results	Acceptance Criteria
1	Limiting Break	DBA (Recirculation Line)	
2	Limiting ECCS Failure	LPCI Injection Valve	
3	Peak Cladding Temperature	< 2164 °F	< 2200 °F
4	Maximum Local Oxidation	< 9.0%	< 17%
5	Core-Wide Oxidation	< 0.8%	< 1%
6	Coolable Geometry	Items 3 and 4	PCT < 2200 °F and Local Oxidation < 17%
7	Long Term Cooling	Core Reflooded or One Core Spray Pump Operating	Long Term Decay Heat Removal

Table 6.3-13c

SAFER/GESTR-LOCA EVENT SCENARIO
FOR 100% DBA SUCTION LINE BREAK
AND A DIESEL GENERATOR FAILURE WITHOUT HPCI
USING APPENDIX K ASSUMPTIONS
FOR GE14, 9x9-2 AND ATRIUM-9B AT 2957 MWt

EVENT	TIME (sec)
Break Occurs	0.0
High Drywell Pressure Trip (assumed)	0.0
Signal to Start CS	1.0
Signal to Start LPCI	1.0
Signal to Start Diesel Generator	1.0
Low-Low Water Level Trip	3.1
MSIVs Close	3.5
1st Peak PCT (GE14) Occurs	4.8
Top of Jet Pumps Uncovers	4.9
Feedwater Flow Reaches Zero	5.0
Suction Line Uncovers	6.9
Lower Plenum Flashes	7.6
Diesel Generator at Rated Speed and Bus Powered	17.0
PCT Node Uncovers	17.3
CS/LPCI IV Pressure Permissive Reached	23.3
LPCI Pump at Rated Speed	31.0
CS Pump at Rated Speed	36.0
CS Injection Occurs	36.0
CS at Rated Flow	43.7
LPCI Injection Valves Full Open	54.3
Recirc Discharge Valve Closed	69.0
LPCI Injection Starts	69.0
LPCI at Rated Flow	69.0
CS Injection Valves Full Open	77.3
2nd Peak PCT (GE14) Occurs	174.4

Table 6.3-13d

WESTINGHOUSE LOCA EVENT SCENARIO FOR 100% DBA SUCTION LINE BREAK AND LPCI INJECTION VALVE FAILURE USING APPENDIX K ASSUMPTIONS FOR SVEA-96 OPTIMA2 FUEL AT 2957 MWt

Event	Time (seconds)
Break / loss of off site power occurs	0.0
Turbine stop valve closes on loss of off site power	0.1
High drywell pressure occurs	0.2
Reactor scram signal on high drywell pressure	1.2
Top of jet pumps uncover	3.3[2]/3.2[3]
Suction line uncovers	4.9
Reactor low-low water level (L2) reached	5.5
Lower plenum flashes	6.3
Diesel generators at rated speed and bus powered	16
LPCS pressure permissive reached	23.1[2]/23[3]
Mid plane uncovers	24.4[2]/25[3]
Lower Plenum flashing ends	30
LPCS pumps start	31.2[2]/31[3]
LPCS injection occurs	31.2[2]/31[3]
LPCS pumps at full speed	36.2[2]/36[3]
LPCS pumps deliver rated flow	41.6[2]/45[3]
LPCS injection valves full open	53.2[1,2]/53[1,3]
Core spray minimum flow valve full closed	59
Peak clad temperature occurs	176.5[2]/175[3]

1. Minimum bypass valves are assumed to be open initially. Core spray minimum flow valves are assumed to be full closed 25 seconds after the valves receive a close signal when core spray flow exceeds 1250 gpm.

2. Event Timing applicable to Unit 2.

3. Event timing applicable to Unit 3.

Table 6.3-14

Table deleted

Table 6.3-15

Table deleted

Table 6.3-16

Table deleted

Table 6.3-17

Intentionally deleted

Table 6.3-18

LONG-TERM NPSH MARGIN

LPCI/CS Pumps	Minimum LPCI Margin (ft)	Minimum CS Margin (ft)
4/2 (5000/4500)	-18.2	-12.1
3/2 (2@2500/1@5000/4500)	-2.5	2.0
2/1 (5000/4500)	-1.1	3.8
1/2 (5000/4500)	1.1	4.2
1/1 (5000/4500)	3.7	6.8

Table 6.3-19a

This table has been intentionally deleted.

Table 6.3-19b

This table has been intentionally deleted.

Table 6.3-19c

LEAKAGE ANALYZED IN DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS FOR GE14, 9X9-2 AND ATRIUM-9B AT 2957 MWt

Source	Analyzed Leakage (gpm)
RPV Penetration Assembly Design Leakage + Upper T-Box Vent Hole Leakage + Core Spray Weld Piping Cracks End-Of Cycle Leakage (1-Loop)	250
Core Shroud Weld Cracks	184
Access Hole Cover	78
Bottom Head Drain	Explicitly accounted for in break area.
Jet pump bolted joint (total for 10 jet pumps)	582
Jet pump riser crack	32.33

Table 6.3-19d

LEAKAGE ANALYZED IN DRESDEN WESTINGHOUSE LOCA ANALYSIS FOR SVEA-96 OPTIMA2 FUEL AT 2957 MWt

Description	Analyzed Leakage (gpm)	Notes
LPCS (per pump)		
Outside Shroud	186[1] / 250[2]	Leakage is modeled proportionately to the runout injected flow. Leakage added to downcomer.
Inside Shroud	187[1] / 403.5[2]	Leakage is modeled proportionately to the runout injected flow. Leakage added to upper plenum.
LPCI		
Jet pump leaks	14.33	Leakage is modeled proportionately to the runout injected flow. Leakage added to downcomer.
Jet pump slip joints	225	Distributed over all 20 jet pumps and based on 2/3 core height flooding. Leakage added to downcomer.
Shroud		
Upper	0	
Lower	262	Based on prescribed initial operating conditions. Leakage varies with calculated pressure differences. Leakage added to downcomer.
Lower head drain to recirculation suction line	104	Based on 2/3 core height flooding. Leakage added to recirculation suction line of the unselected loop.

1. Assumption applicable to Unit 2.

2. Assumption applicable to Unit 3.

Table 6.3-20

This table has been intentionally deleted.

Table 6.3-20b

PLANT PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, 9X9-2 AND ATRIUM-9B AT 2957 MWT

Plant Parameters	Nominal	Appendix K
Core Thermal Power[(1)] (MWt)	2957	3016
Corresponding Power (% of 2957 MWt)	100	102
Vessel Steam Output (1bm/hr)	11.71×10^6	11.97×10^6
Rated Core Flow (1 bm/hr)[(2)]	98×10^6	98×10^6
Vessel Steam Dome Pressure (psai)	1020	1020
Maximum Recirculation Suction Line Break Area (ft^2)	4.281[(3)]	4.281[(3)]

(1) The core thermal power corresponds to 117% of the pre-LPU value of 2527 MWt.

(2) Rated core flow but the limiting LOCA cases were analyzed for a core flow range of 95% to 108% of rated core flow.

(3) Includes area of bottom head drain.

Table 6.3-20b

ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, 9X9-2 AND ATRIUM-9B AT 2957 MWT

1. Low Pressure Coolant Injection (LPCI) System

Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid	250
b. Minimum flow with minimum flow bypass valve open		
• Vessel pressure at which below listed flow rates are quoted	psid (vessel to drywell)	20
• 2 LPCI pumps injecting into the lower plenum	gpm	7690
• 4 LPCI pumps injecting into the lower plenum	gpm	12190
c. Minimum flow at 0 psid with minimum flow valve open		
• 2 LPCI pumps injecting into the lower plenum	gpm	8060
• 4 LPCI pumps injecting into the lower plenum	gpm	12690
d. Initiating Signals		
• Low-low water level	inches (above vessel zero)	444
or		
• High drywell pressure	yes/no	yes(1)
e. Vessel pressure at which injection valve may open	psid	300
Time from initiating signal (Item 1.d) to system capable of delivering full flow (power available, pump at rated speed, injection valve fully open, and discharge valve closed)	sec	68
g. Injection valve stroke time-opening(2)	sec	30
h. Recirculation discharge valve stroke time closing(3)	sec	48
i. Minimum detectable break size	ft^2	0.15

(1) SAFER does not model the drywell pressure, so the drywell pressure setpoint is not actually used in the analysis. However, the modeling assumes that the setpoint is reached at the start of the event.

(2) The analysis assumes no LPCI flow until the injection valve is fully open.

(3) The analysis assumes no LPCI flow until the discharge valve is fully closed.

Table 6.3-20b

ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, 9X9-2 AND ATRIUM-9B AT 2957 MWT

2. Core Spray (CS) System

Variable	Units	Analysis Value
a. Maximum vessel pressure at which pumps can inject flow	psid (vessel to drywell)	314
b. Minimum flow with min. flow valve open		
• Vessel pressure at which below listed flow rate is quoted	psid (vessel to drywell)	90
• Minimum flow to upper plenum	gpm	3850
c. Minimum flow to upper plenum at 0 psid with min. flow valve open	gpm	4740
d. Initiating Signals		
• Low-low water level	inches (above vessel zero)	444
or		
• High drywell pressure	yes/no	yes[4]
e. Vessel pressure at which injection valve may open	psid	300
f. Injection valve stroke time-opening[5]	sec	53
g. Time from initiating signal (Item 2.d) to system capable of delivering full flow (power available, pump at rated speed and injection valve fully open)	sec	68

(4) SAFER does not model the drywell pressure, so the drywell pressure setpoint is not actually used in the analysis. However, the modeling assumes that the setpoint is reached at the start of the event.

(5) The analysis takes credit for core spray flow with the valve partially open after the pump is at rated speed.

Table 6.3-20b

ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, 9X9-2 AND ATRIUM-9B AT 2957 MWT

3. High Pressure Coolant Injection (HPCI) System

Variable	Units	Analysis Value
a. Operating vessel pressure range		
• Minimum pressure	psia	165
• Maximum pressure	psia	1,135
b. Minimum flow required over the entire pressure range	gpm	4,400
c. Maximum vessel pressure at which pump can inject flow	psia	1,135
d. Initiating Signals		
• Low-low water level	inches (above vessel zero)	444
or		
• High drywell pressure	yes/no	yes[6]
e. Maximum allowable time delay from initiating signal (Item 3.d) to system capable of delivering full flow (pump at rated speed and injection valve fully open)	Sec	48

(6) SAFER does not model the drywell pressure, so the drywell pressure setpoint is not actually used in the analysis. However, the modeling assumes that the setpoint is reached at the start of the event.

Table 6.3-20b

ECCS PARAMETERS USED IN
DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS
FOR GE14, 9X9-2 AND ATRIUM-9B AT 2957 MWT

4. Automatic Depressurization System (ADS)

Variable	Units	Analysis Value
a. Number of ADS valves		
• Total number of relief valves with ADS function		5
• Total number of relief valves with ADS function assumed available in the analysis		5
b. Pressure at which below listed capacity is quoted	psid	1,135
c. Minimum flow capacity for one ADS valve	lbm/hr	540,000
d. Initiating Signals		
• Low-low water level	inches (above vessel zero)	444
and		
• ADS Timer Delay – maximum	sec	121.85

Table 6.3-20c
PLANT PARAMETERS USED IN
DRESDEN WESTINGHOUSE LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

A. PLANT PARAMETERS (APPENDIX K)		
	Units	Analysis Value
Core Thermal Power	MWt	3016
% of Rated Core Thermal Power	%	102
Vessel Steam Output	Mlbm/hr	11.95
% of Rated Steam Output	%	102
Core Flow	Mlbm/hr	93.39 – 105.84
% of Rated Core Flow	%	95.3 – 108
Vessel Steam Dome Pressure	psia	1020
Maximum Recirculation Line Break Area	ft^2	3.62[1]

[1] Pump suction leg pipe area. Bottom head leakage area handled separately.

Table 6.3-20c
PLANT PARAMETERS USED IN
DRESDEN WESTINGHOUSE LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

B. EMERGENCY CORE COOLING SYSTEM PARAMETERS		
Low Pressure Coolant Injection System	Units	Analysis Value
System Pressure – Flow Delivery (2 pumps injecting into recirculation loop discharge piping)	gpm/psid	0 / 275 6000 / 150 9000 / 20 9400 / 0
System Pressure – Flow Delivery (4 pumps injecting into recirculation loop discharge piping)	gpm/psid	0 / 275 10000 / 150 14200 / 20 14700 / 0
Maximum Reduction In LPCI Due To Minimum Flow Bypass (2 pumps)	gpm	695
Initiating Signals		
Low-Low Water Level AND Low Reactor Vessel Pressure OR	inch/psig	444[2] / 300
High Drywell Pressure OR	psig	2.5
Low-Low Water Level AND Time Delay	inch/sec	444 / 600
Reactor Vessel Pressure at Injection Valve May Open	psig	300
Injection Valve Stroke Time	sec	30
Recirculation Discharge Valve Stroke Time	sec	45[3]
Minimum Break Size for Which Loop Selection Logic Assumed to Select Intact loop	ft^2	0.15
Time for Diesel Generator Output Closure	sec	16.0
Swing Bus Transfer Time	sec	26
Time to Load Pump A	sec	4
Time to Load Pump B	sec	9.7[4]
Time for Pump to Reach Rated Speed	sec	5.3

[2] Above vessel zero
[3] After closure pressure permissive for loop selection for single loop operation (860 psig, analysis value is 800 psig) and time delay for loop selection (5.25 sec)
[4] Time to load pump B has applied an additional 0.3 sec delay for conservatism.

Table 6.3-20c
PLANT PARAMETERS USED IN
DRESDEN WESTINGHOUSE LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

B. EMERGENCY CORE COOLING SYSTEM PARAMETERS (CONTINUED)		
Low Pressure Core Spray System	Units	Analysis Value
System Pressure – Flow Delivery	gpm/psid	0 / 325 3000 / 200 4500 / 90 (5500 / 0)[1] (5650 / 0)[2]
Maximum Reduction in LPCS Due to Minimum Flow Bypass	gpm	308
Maximum Core Spray Delivery to Initiate Isolation of Minimum Flow Bypass	gpm	1250
Maximum Stroke Time for Minimum Flow Bypass Isolation Valve	sec	25
Initiating Signals		
Low-Low Water Level AND Low Reactor Vessel Pressure OR	inch/psig	444 / 300
High Drywell Pressure OR	psig	2.5
Low-Low Water Level AND Time Delay	inch/sec	444 / 600
Reactor Vessel Pressure at Injection Valve May Open	psig	300
Injection Valve Stroke Time	sec	30
Time for Diesel Generator Output Closure	sec	16.0
Time to Load Pump	sec	15.2
Time for Pump to Reach Rated Speed	sec	5

1. Assumption applicable to Unit 2.

2. Assumption applicable to Unit 3.

Table 6.3-20c
PLANT PARAMETERS USED IN
DRESDEN WESTINGHOUSE LOCA ANALYSIS
FOR SVEA-96 OPTIMA2 AT 2957 MWt

B. EMERGENCY CORE COOLING SYSTEM PARAMETERS (CONTINUED)		
High Pressure Coolant Injection System	Units	Analysis Value
Operating Reactor Vessel Pressure Range	psid	150 – 1120
Minimum Rated Flow Over Range	gpm	5000
Initiating Signals		
Low-Low Water Level OR	inch	444
High Drywell Pressure	psig	2.5
Maximum Time Delay from Initiating Signal to Rated Flow Available and Injection Valve Full Open	sec	45
Automatic Depressurization System		
Total Number of Valves Installed	--	5
Number of Valves Used in Analysis	--	5
Valve Capacity		
4 Relief Valves (each)	Mlb/hr	0.540 at 1135 psig
1 Safety / Relief Valve	Mlb/hr	0.622 at 1125 psig
Initiating Signals		
Low-Low Water Level AND	inch	444
High Drywell Pressure AND	psig	2.5
Timer 1 Delay AND	sec	120
Low Pressure ECCS Pump Running with Sufficient Discharge Pressure OR		
Low-Low Water Level AND	inch	444
Timer 2 Delay AND	sec	600
Low Pressure ECCS Pump Running with Sufficient Discharge Pressure		
ADS Re-close on Reactor Vessel Pressure	psig	50
ADS Reopen on Reactor Vessel Pressure	psig	100
Valve Opening Time	sec	0.4
Valve Closing Time	sec	10

Table 6.3-21

This table has been intentionally deleted.

Table 6.3-21b

SINGLE FAILURE EVALUATION IN DRESDEN/QUAD CITIES SAFER/GESTR-LOCA ANALYSIS FOR GE14, 9X9-2 AND ATRIUM-9B AT 2957 MWT

Assumed Failure[(1)]	System Remaining[(2)(3)]
Diesel Generator (D/G) or 125 Volt DC Battery	5 ADS, 1 CS, HPCI, 2 LPCI[(4)]
LPCI Injection Valve (LPCI IV)	5 ADS, 2 CS, HPCI
HPCI	5 ADS, 2 CS, 4 LPCI
ADS	4 ADS, 2 CS, 4 LPCI, HPCI

(1) Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the assumed failures.
(2) Systems remaining, as identified in this table, are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed, less the ECCS system in which the break is assumed.
(3) The small break analyses were performed with all ADS valves assumed operable except for when it was the single failure.
(4) The D/G failure is analyzed with and without HPCI, although there is no single failure in Dresden/Quad Cities that will fail both the D/G and HPCI. The D/G failure without HPCI has the same available systems as the battery failure in the generic analysis. The large break analysis does not take credit for HPCI and the small break analysis does not permit a D/G failure without HPCI.

Table 6.3-21c
SINGLE FAILURE EVALUATION USED IN WESTINGHOUSE DRESDEN LOCA ANALYSIS FOR SVEA-96 OPTIMA2 FUEL AT 2957 MWt

Assumed Failure[2]	Systems Remaining[3]
LPCI Injection Valve	2 LPCS, HPCI, 5 ADS
Diesel Generator or 125-VDC	1 LPCS, 2 LPCI, HPCI, 5 ADS
HPCI	2 LPCS, 4 LPCI, 5 ADS
Loop Select Logic	2 LPCS, 4 LPCI, HPCI, 5 ADS
ADS	2 LPCS, 4 LPCI, HPCI, 4 ADS

[2]Other postulated failures are not specifically considered because they all result in at least as much ECCS capacity as one of the assumed failures.
[3] Systems remaining as identified in this table are applicable to all non-ECCS line breaks. For a LOCA from an ECCS line break, the systems remaining are those listed less the ECCS system in which the break is assumed.

Table 6.3-22

This table has been intentionally deleted.

Table 6.3-23

This table has been intentionally deleted.

6.4 HABITABILITY SYSTEMS

Habitability systems are provided to ensure that control room operators are able to remain in the control room, operate the plant safely under normal conditions, and maintain the plant in a safe condition under accident conditions. The worst-case design basis accident (DBA) for habitability considerations is postulated as a loss-of-coolant accident (LOCA) with main steam isolation valve leakage at Technical Specification limits. The control room is included in the control room envelope (CRE) as described in Section 6.4.2.1.

The habitability systems consist of systems and equipment which protect the control room operators against such postulated releases as radioactive materials, toxic gases, and smoke. Detailed descriptions of the various habitability provisions are discussed in other sections of the UFSAR, as stated below:

A. Tornado protection is addressed in Section 3.3;

B. Flood protection is discussed in Section 3.4;

C. Lighting systems are described in Section 9.5.3;

D. Protection against dynamic effects associated with the postulated rupture of piping is addressed in Section 3.6; and

E. Plant communication systems are described in Section 9.5.2.

6.4.1 Design Basis

The control room and its supporting systems are designed to ensure that doses to its occupants do not exceed the limits of 10 CFR 50.67 and GDC 19. The supporting radiological analysis is done in accordance with USNRC Regulatory Guide 1.183.

6.4.2 System Design

The Dresden Station has the following capabilities to ensure habitability of the control room envelope (CRE) under accident conditions:

A. The control room heating, ventilation, and air conditioning (HVAC) systems are capable of maintaining the control room atmosphere suitable for occupancy throughout the duration of a DBA.

B. The control room area contains food, adequate water and sanitary facilities. All these are available within the control room envelope (CRE). A supply of potassium iodide is available in the plant.

C. The HVAC systems are capable of detecting and protecting control room personnel from radioactive contamination or smoke released to the atmosphere.

D. Emergency breathing air, supplied by a bottled air reservoir or by self-contained air packs, is provided to protect control room personnel from exposure to contaminated air.

E. The HVAC system Train A is capable of manual transfer from the normal operating mode to the smoke purge mode. The HVAC systems are capable of manual transfer from the normal operating mode to the isolation/pressurization or isolation/recirculation modes. Emergency monitors and control room equipment are provided as necessary to ensure this capability, as described in Sections 6.4.4.1, 6.4.4.2, and 6.4.4.3.

The control room is a Class I structure. Seismic design is addressed in Section 3.7. Seismic qualification of instruments and electrical equipment is addressed in Section 3.10. Missile protection is addressed in Section 3.5.

6.4.2.1 Definition of Control Room Envelope

SRP 6.4 provides guidance for defining the boundaries for a control room envelope. Within this zone, the plant operators are adequately protected against the effects of accidental radioactive gas releases. This zone also allows the control room to be maintained as the center from which emergency teams can safely operate during a design basis radiological release. To accomplish this, the following areas are included in the envelope:

A. Main control room for Units 1, 2, and 3, which includes kitchen, toilet, and locker rooms;

B. Train B HVAC equipment room.

Areas outside the CRE are isolated in emergency conditions. Support rooms such as the Shift Manager's office are accessible to operators with the aid of breathing equipment. The auxiliary computer room is permanently isolated from the CRE. The Train A HVAC equipment room, the auxiliary electrical equipment room, and the auxiliary computer room are not included in the CRE. The boundaries of the CRE are shown on Figure 6.4-1.

Figure 6.4-2 shows the arrangement of equipment in the control room and points of entry. Figure 6.4-3 is a plan view showing the location of radioactive material release points and control room air inlets.

6.4.2.2 Ventilation System Design

The HVAC equipment described in this section is also discussed in Section 9.4.1, which explains normal use of the equipment. This section addresses emergency service requirements and the response and operation of control room HVAC equipment under emergency conditions. The control room HVAC system is shown in the control room HVAC P&IDs: Drawings M-273, Sheet 1 and 2, and Drawing M-3121.

The control room HVAC system consists of a Train A HVAC system, a Train B HVAC system, an air filtration unit, and a smoke detection system. The multizone Train A system is the primary train for the control room envelope. Since Train A is used primarily during normal operations, it is described in Section 9.4.

The Train B HVAC system is a single zone system which provides the necessary cooling required in case of failure of the Train A system. The discharge air from the air handling unit (AHU) is divided into two zones, zone 1 is ducted to the control room and zone 2 is ducted to the Train B HVAC equipment room . The air distribution from each train is aligned through the use of air-operated isolation dampers. These dampers fail to the Train B mode since this train is powered from the emergency bus during a loss of offsite power (LOOP). The Train B AHU contains a centrifugal supply air fan, a direct-expansion cooling coil, and a medium-efficiency filter bank.

Train B provides cooling through the use of a reciprocating compressor and direct-expansion cooling coil. The condensing unit is normally cooled with the service water system. However, upon loss of service water, the condenser may be cooled with the containment cooling service water (CCSW) system. The CCSW supply to the refrigerant condenser can be drawn from either loop of the Unit 2 CCSW system. Refer to Section 9.2.1.2 for a description of the CCSW system.

The air filtration unit (AFU) complies with Regulatory Guide 1.52 and is located in the Train B HVAC equipment room.

The Train A makeup air intake and exhaust dampers are bubble tight, with an area of 25 square feet each. The isolation dampers for the AFU bypass intake, kitchen and locker room/toilet exhaust ducts are leak tight. Isolation of the normal makeup air intake takes approximately 20 seconds.

6.4.2.3 Leak-Tightness

The infiltration of unfiltered air into the control room emergency zone occurs through three different paths:

A. Through the emergency zone boundary;

B. Through the system components located outside the emergency zone; and

C. Through backflow at the zone boundary doors as a result of ingress or egress to or from the emergency zone.

Using the guidance of SRP 6.4, the infiltration through the emergency zone boundary is assumed to be zero when the system is in the isolation/pressurization mode. During emergency pressurized modes of operation, the control room ventilation system supplies 2000 ft^3/min (standard) of outdoor air to maintain the control room at 1/8-in.H_2O positive pressure with respect to the adjacent areas. Intentionally admitting outdoor air into the emergency zone prevents infiltration through the emergency zone boundary by assuring that air is exfiltrating from the zone at an adequate velocity (a velocity through the emergency zone boundary penetrations of approximately 1400 ft/min is required to develop a backpressure of 1/8-in.H_2O).

During the isolation/recirculation mode, infiltration through the emergency zone boundary is initially negligible because the control room will be at a positive pressure at the time of system isolation.

In support of the full implementation of Alternate Source Term (AST) as described in and in accordance with the guidance of Regulatory Guide 1.183, Alternate Source Term (AST) radiological consequence analyses are performed for calculation of offsite and control room personnel Total Effective Dose Equivalent (TEDE) doses. Radiological consequences of infiltration are included in the radiological assessment addressed in USFAR 15.6.5.5. The ductwork and components under negative pressure and located outside the control room envelope are shown on Figure 6.4.1.

The infiltration analysis resulted in a total unfiltered infiltration rate of 263 ft^3/min (standard). The ductwork and components that are under a negative pressure and are located outside the emergency zone are shown on Figure 6.4-1. This figure also shows the leakage flowrate through the various components. A breakdown of the infiltration through the different leakage paths as is currently measured is shown in Table 6.4-1. Radiological consequences of infiltration are included in the radiological assessment addressed in UFSAR Section 15.6.5.5.2.

6.4.2.4 Interaction with Other Zones and Pressure-Containing Equipment

Potential adverse interactions between the control room emergency zone and adjacent zones that may allow the transfer of toxic or radioactive gases into the control room are minimized by maintaining the control room at a positive pressure of 1/8-in.H_2O during the isolation pressurization mode, with respect to adjacent areas. In addition, both the intake dampers and the dampers which isolate the emergency zone are automatically isolated or actuated by the operator in response to the odor of toxic gas or the reactor building ventilation system high radiation alarm.

Steam lines are not routed in the vicinity of any control room wall. Pressurized breathing air cylinders are located above the control room.

6.4.2.5 Shielding Design

The control room design consists of poured-in-place reinforced concrete with 6-inch floor and ceiling slabs and 18- to 27-inch walls. The radiation streaming effect in the control room is considered negligible during normal operation and provides 30-day integrated dose post-LOCA as considered in section 15.6.5. This dose estimate is expected to increase by 19% following extended power uprate. Further details of the design of the control room shielding are contained in Section 12.3.2.2.4. Figures 12.3-1 through 12.3-5 illustrate the relative location of the control room and radiation sources and show the paths and shield thicknesses.

6.4.3 System Operational Procedures

For normal conditions, the Train A HVAC system operates as discussed in Section 9.4.1. If desired, Train B can be used for normal plant operations. Outside air is supplied to Train B by the AHU fan in this operating mode. Upon failure of the operating HVAC system train, that train is isolated and the redundant train is energized.

The control room HVAC system has three emergency modes:

A. The isolation/pressurization mode protects the control room personnel from airborne radioactive contaminants. In this mode, the normal outside air intakes are isolated, and the AFU provides makeup air to maintain pressurization. This mode is described more fully in Section 6.4.4.1.

B. The isolation/recirculation mode protects personnel from toxic gases. In this mode, all outside air intakes are isolated, and the control room air is recirculated through the operating HVAC train. This mode is described more fully in Section 6.4.4.2.

C. The smoke purge mode protects personnel from fire and smoke. In this mode, the Train A control room HVAC System exhausts 100% of the control room envelope air and replaces it with 100% outside air. This mode is described more fully in Section 6.4.4.3.

6.4.4 Design Evaluations

This section evaluates the effectiveness of the HVAC system design in protecting the control room personnel from the postulated hazards of radioactive material, toxic gases, and smoke contaminating the control room atmosphere.

6.4.4.1 Radiation Protection

The control room HVAC system provides radiation protection by pressurizing the control room emergency zone with filtered air, isolating the normal outdoor air intakes, and isolating the kitchen and locker room exhaust fan dampers. This zone isolation with a filtered pressurization air-type system provides radiation protection by minimizing the infiltration of unfiltered air into the control room emergency zone. A positive pressure of 1/8-in.H_2O with respect to adjacent areas is maintained by passing 2000 ft^3/min of outdoor air through a HEPA filter unit tested and maintained in accordance with Technical Specification 5.5.7, Ventilation Filter Testing Program. The filter unit, booster fans, and associated controls are powered from the emergency bus.

Radiation protection is provided to allow control room access and occupancy for the duration of a DBA. Satisfactory protection is provided based on isolating and pressurizing the control room emergency zone with filtered outdoor air no later than 40 minutes after radiation has been detected in the reactor building ventilation manifolds.

Operator action is required within the time limit specified above to isolate the control room emergency zone and to activate the air filter unit. Isolation consists of closing the outdoor air intakes for both the Train A and B systems and closing the kitchen and locker room exhaust isolation dampers. Additionally, the exhaust fans are tripped from limit switches on the isolation dampers, thereby preventing the induction of unfiltered air into the control room via the exhaust duct.

In the event of a LOOP or loss of instrument air, the isolation dampers fail to the isolation/pressurization mode. However, the pneumatic AFU booster fan discharge dampers also fail closed, thereby requiring manual operation prior to activating the booster fans during loss of instrument air. This failure mode is required to protect the emergency zone from a toxic chemical release during a loss of instrument air.

Section 15.6.5.5 contains an evaluation of the maximum expected dose to the control room during a DBA LOCA. The present analysis utilizes the Alternative Source Term (AST) methodology and conforms to USNRC Regulatory Guide 1.183. The resulting doses are within the limits of 10 CFR 50.67.

6.4.4.2 Toxic Gas Protection

The control room HVAC system does not provide automatic toxic gas protection to the control room emergency zone in case of either an onsite or offsite toxic chemical accident. The results of the toxic chemical survey are provided in Section 2.2.3. An analysis of survey results was carried out to conform to Regulatory Guide 1.78, which discusses the requirements and guidelines to be used for determining the toxicity of chemicals in the control room following a postulated accident. The guidelines for determining the toxicity of a given chemical include quantity, shipment frequencies, distance from source to site, and general properties of the chemical such as vapor pressure and toxicity limits.

6.4.4.2.1 Analysis Assumptions

Three types of standard limits are considered in defining toxicity. The first limit is the toxicity limit, which is the maximum concentration that can be tolerated for 2 minutes without physical incapacitation of an average human. If the toxicity limit is not available for a given chemical, other limits, called the short-term exposure limit (STEL), or the threshold limit value (TLV), are used. STEL is defined as the maximum concentration to which workers can be exposed for 15 minutes without suffering from irritation, tissue damage, narcosis leading to accident proneness, or reduction of work efficiency. The TLV is defined as the concentration below which a worker may be exposed 8 hours per day, 5 days per week without adverse health effects. These limits are taken from Regulatory Guide 1.78 and References 1 and 2.

Based on the toxicity guidelines given in Regulatory Guide 1.78, compounds were screened based on toxicity, quantity, and distance from source to the Dresden Station control room air intake to determine if air dispersion modeling would be required to determine the potential concentration of each compound in the control room.

For the initial screening of compounds, spill, release, and air dispersion models were selected from version 1.0 of a software program entitled Automated Resource for Chemical Hazard Incident Evaluation (ARCHIE) prepared by the Federal Emergency Management Agency.[3] Flash calculations for subcooled gases or superheated liquids are taken from Reference 4. The concentration rise in the control room was calculated from NUREG-0570.

The models include a consideration of the following assumptions:

A. Chemicals in the analysis include:

   1. Chemicals listed in Regulatory Guide 1.78, Table C-1;

   2. Chemicals included in the original Control Room Habitability Study[5] and found to be still present in greater than threshold quantities; and

   3. Chemicals identified as being stored onsite at Dresden Station.

B. Threshold quantities for chemicals included in the analysis include:

   1. Highway shipments - 10 tank trucks per year;

   2. Rail shipments - 30 tank cars per year;

   3. Barge shipments - 50 barges per year;

   4. Onsite chemicals - greater than 100 pounds stored in a singe container; and

5. Offsite facilities - threshold quantities determined via procedure given in Regulatory Guide 1.78.

C. There is a failure of one container of toxic chemicals being shipped on a barge, tank car, or tank truck releasing all of its contents to the surroundings. Instantaneously, a puff of that fraction of chemical which would flash to a gas at atmospheric pressure is released. The remaining chemical is assumed to spread uniformly on the ground and boil or evaporate as a function of time due to the heat acquired from the sun, ground, and surroundings. Further, no losses of chemicals are assumed to occur as a result of absorption into the ground, cleanup operations, or chemical reactions.

D. A spill from a railroad tank car is assumed to spread roughly over a circular area. Similarly, a spill occurring in the highways is also assumed to spread over a circular area.

E. The initial puff due to flashing, as well as the continuous plume due to evaporation, is transported and diluted by the wind to impact on the control room inlet. The atmospheric dilution factors are calculated based on the methodology of Regulatory Guide 1.78 and NUREG-0570.

F. Modeling is based on maximum concentration chemical accidents for offsite releases. Maximum concentration-duration chemical accidents were not considered due to an inability to obtain information on safety relief valves. It is believed that maximum concentration chemical release will provide conservative worst case accident scenarios as compared to maximum concentration-duration chemical releases.

G. To determine which chemicals need monitoring, the control room ventilation systems were assumed to continue normal operation for the analysis. The chemical concentrations as a function of time were calculated and the maximum levels determined. These were compared to the toxicity limits. Wherever the toxicity limits were not available, STEL values, or TLVs were used in lieu of toxicity limits.

H. When the concentration in the control room does not exceed the toxicity limit within 2 minutes after detection by odor, operator action to isolate the control room was assumed. Wherever the toxicity limits were not available, STEL values, or TLVs were used in lieu of toxicity limits.

The control room outdoor concentration is calculated for each compound studied using the atmospheric dispersion model. The control room indoor concentration is computed from the outdoor concentration and the control room air exchange rate. Both concentrations, outdoor and indoor, are functions of time for specific meteorological conditions.

The chemical concentration inside the control room reaches the odor detection limit at time t_1 minutes. The chemical concentration inside the control room continues to build up to the toxicity limit at time t_2 minutes. The time required for buildup of a hazardous chemical from the odor detection concentration to the toxicity limit inside the control room is calculated as (t_2 - t_1) minutes. In Regulatory Guide 1.78, 2 minutes is considered sufficient time for a trained operator to put self-contained breathing apparatus (SCBA) into operation. The estimated time (t_2 - t_1) is compared against the 2 minutes. If the time (t_2 - t_1) is less than 2 minutes, it means that the operator would not have sufficient time to put a SCBA on. In this case the control room is considered to become uninhabitable during the chemical release under specific meteorological conditions.

The air dispersion model included in the ARCHIE software calculates peak concentration of compounds at the control room air intake. The time required for buildup of a chemical from odor detection to the toxicity limit was calculated using this peak concentration. Using this calculation procedure a list of compounds was put together where (t_2 - t_1) was less than 2 minutes. These compounds were then studied in more detail using an air dispersion model following Regulatory Guide 1.78 methodology which factors in the time dependance of concentration at the control room air intake. This model gives a more accurate estimation of potential control room concentrations than the ARCHIE software which overestimates these concentrations.

6.4.4.2.2 Analysis Results

The onsite chemicals listed in Table 2.2-7 were screened and analyzed[6] to determine if the release of any of those chemicals could pose a threat to control room habitability. The screening shows that none of the chemicals stored onsite pose a threat.

The offsite chemicals considered include the chemicals listed in Regulatory Guide 1.78, along with those chemicals listed in the original Bechtel Control Room Habitability Study.[5] Each of the chemicals included in the analysis was evaluated based on toxic, physical, and chemical properties. Some were eliminated based on Regulatory Guide 1.78 (Table C-2) criteria. The remaining chemicals were analyzed assuming a fresh air intake of 2000 ft^3/min to the air handling system and no isolation. At this flowrate, without isolation, the following chemicals exceeded the toxicity limit or TLV in the control room: acrylonitrile, ammonia, 1,3-butadiene, chlorine, ethylene oxide, and hydrochloric acid. Detailed analyses for each of these chemicals are provided in Reference 6. Protection provisions are described below.

6.4.4.2.3 Protection Provisions

Operators are protected against the above chemicals by placing the control room HVAC system in the isolation/recirculation mode. This isolation mode provides for 100% recirculated air with no outside makeup. Operator action to isolate the control room is required (within 2 minutes after detection of odor) for chemicals whose control room concentrations would otherwise exceed the toxicity limits after that time. The chemicals requiring operator action are hydrochloric acid, chlorine, and 1,3-butadiene.

The concentration of acrylonitrile could slightly exceed the TLV in approximately 42 minutes after the plume reaches the control room air intake. This concentration is an order of magnitude below the toxicity limit and the odor threshold. The TLV has been established based on chronic effects, and for this reason air monitoring for this chemical is not necessary.

The estimated probabilities of control room uninhabitability due to release of ammonia or ethylene oxide are an order of magnitude below the SRP 2.2.3 criterion for realistic estimates. Therefore, the proposed risk is acceptable and monitoring is not required.

6.4.4.3 Fire and Smoke Protection

The control room HVAC system is designed to isolate and maintain the design conditions within the control room during fires in either the control room or outside the emergency zone.

Smoke detectors, located in the control room return air ducts, will annunciate in the control room and the Train A HVAC system will be switched manually to the smoke purge mode. During this mode, the system supplies 100% outdoor air. This will prevent the recirculation of smoke into any of the occupied areas in the event of fire while exhausting 100% of the return air to the outdoors. The smoke purge capability is only available on Train A.

A smoke detector in the Train A control room HVAC System outside air intake will annunciate and the Train A HVAC system will be manually switched to the recirculation mode. This will prevent the intake of smoke into the control room envelope in the event of an outside fire adjacent to the Train A HVAC system outside air intake.

SCBA units are located in the control room. In addition, a bank of emergency air bottles is located in the Unit 2 battery room, and can be connected to the SCBAs by 50-foot hoses stored in the control room. The control room emergency air system can be used during release of radioactivity, toxic gas, or smoke.

6.4.5 Testing and Inspection

The AFU is periodically operated and tested in accordance with Technical Specification Section 5.5.7, Ventilation filter Testing Program.

6.4.6 Instrumentation Requirements

The AFU has instrumentation installed to support the testing outlined in Section 6.4.5. Differential pressure is monitored across the rough prefilter, the HEPA prefilter, the HEPA afterfilter, and the complete unit. Temperature is monitored at the inlet, after the electric heater, and after the activated carbon adsorber bed. An additional readout is provided as part of the electric heater temperature control circuit. The temperature element after the activated carbon adsorber provides an interlock to allow the fire protection deluge to be activated.

6.4.7 References

1. Dangerous Properties of Industrial Materials, Irving Sax, Richard Lewis, Van Nostrand Reinhold, N.Y., N.Y., 1989.

2. Technical Guidance for Hazardous Analysis, U.S. EPA, 1987.

3. Handbook of Chemical Hazard Analysis Procedures, Federal Emergency Management Agency, 1989.

4. Estimating Releases and Waste Treatment Efficiencies for the Toxic Chemical Release Inventory Form, U.S. EPA document 560/4-88-002, December 1987.

5. Control Room Habitability Study for Dresden Units 2 and 3, Commonwealth Edison Company, Bechtel Power Co., December 1981.

6. Control Room Habitability Study Update for Dresden Units 2 and 3, Commonwealth Edison Company, Scientech Inc., December 2000.

Table 6.4-1

Deleted

6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS

6.5.1 Engineered Safety Feature Filter Systems

The secondary containment system is the only engineered safety feature (ESF) which uses a filter system to control fission product releases. This filter system is the standby gas treatment system (SBGTS) described in Section 6.5.3. The ESFs are described in Section 6.0.

6.5.2 Containment Spray Systems

The containment spray system is part of the containment cooling system described in Section 6.2.2.

6.5.3 Fission Product Control Systems

The SBGTS is provided to maintain a small negative pressure in the reactor building under isolation conditions, in order to prevent ground level escape of airborne radioactivity. Filters are provided to remove radioactive particulates, and charcoal adsorbers are provided to remove radioactive halogens which may be present in concentrations significant to environmental dose criteria. Any radioactive noble gases passing through the filter/adsorbers are diluted with air and dispersed into the atmosphere from the 310-foot chimney. The system is also used to dispose of purge and vent gases from the primary containment, and to assist with containment inerting/deinerting. The exhaust duct radiation monitor provides a continuous indication of radioactivity entering the system, and the chimney monitor samples the effluent. The SBGTS is shown in Drawing M-49. The primary containment vent, purge, and inerting systems are discussed in Section 6.2.5. The radiation monitoring system is discussed in Section 11.5.

6.5.3.1 Design Objectives

The system is sized to maintain the reactor building at a negative pressure of ¼ in.H_2O relative to the atmosphere under neutral wind conditions. The nominal flowrate is 4000 ft^3/min to achieve these objectives. Two separate filter/ adsorber/ fan units are provided. One train is selected as primary and the other train is placed in standby. If the primary train fan or heater fails to start, the standby train will be started automatically. Both units receive power from the emergency electrical supply. The system is designed for Class I seismic conditions. The equipment is located in the shielded center tunnel between the two main condenser rooms. The exhaust pipe runs through the radwaste building and up into the 310-foot chimney.

6.5.3.2 System Description

In the direction of airflow, each standby gas treatment unit has the following major components:

A. Inlet valve - This is a motor-operated butterfly valve which is normally closed. It opens automatically upon system initiation.

B. Cooling air supply line - This line draws 300 ft^3/min of cooling air from the turbine building to remove decay heat from the standby SBGTS train, or can be used to purge contaminated air from the SBGTS area. Upon initiation of the primary train, a normally open motor-operated butterfly valve closes to isolate this train from the line. Cooling air is drawn via the supply line through another normally open valve into the standby train.

C. Demister - The demister reduces the moisture content of the steam-air mixture routed through SBGTS. It consists of a woven nylon mesh which traps water droplets. Water removed from the steam-air mixture is routed through a loop seal arrangement to the "A" waste neutralizer tank in the radwaste building.

D. Electric heater - The electric heater raises the temperature of the entering air by at least 14°F to ensure a relative humidity of less than 70%. The heater energizes automatically upon adequate system flow. Downstream temperature instrumentation provides an alarm in the main control room on high temperature. Station procedures direct operators to shut down the running train to ensure that the activated charcoal bed is not damaged by excessive heat. The heater is powered from the emergency bus.

E. Rough prefilter - The rough prefilter removes dust and other debris which may enter the system. This filter increases the usable life of the downstream high efficiency particulate air (HEPA) prefilter. The prefilter is capable of withstanding a temperature of 500°F.

F. HEPA prefilter - Radioactive particulates entering the SBGTS are removed by the HEPA prefilters. The HEPA filters are designed to have a removal efficiency of not less than 99% for 0.3-µm particles and were factory-tested using PSL spheres to verify this capability. The HEPA prefilter is designed to withstand 500°F temperatures.

G. Activated charcoal adsorber - Filtered air is passed through an activated charcoal adsorber bed capable of removing 95% of fission product iodine. Flowrates above the design range lower air retention time and lower the bed's efficiency. Samples of the carbon are placed in the adsorber inlet for periodic removal and analysis. High temperature charcoal (626°F ignition temperature), framing, and sealing materials are specified. The bed consists of charcoal adsorbent contained in twelve cells. Each cell contains at least 50 pounds of activated charcoal for a total bed weight of at least 600 pounds. The design charcoal adsorption requirement is 95% methyl iodide removal at a relative humidity of 70% and a temperature of 30°C (86°F). The geometry of the SBGTS charcoal cells is shown on

Figure 6.5-2. Replacement charcoal shall be qualified according to the guidelines of Regulatory Guide 1.52.

H. Test orifice - A test orifice is installed downstream of the charcoal adsorber bed. The orifice produces turbulent gas flow for more complete mixing, ensuring that the sample taken is a representative one. This orifice also serves as a flow element to automatically start the standby train on low flow in the primary train.

I. HEPA afterfilter - The HEPA afterfilters are similar to the HEPA prefilters (see Item F) and are provided to remove any activated charcoal particles that may be released from the activated charcoal adsorber.

J. Crosstie line - A crosstie line, with restricting orifice and manual butterfly valve (which is normally locked open), interconnects the two trains so that the operating train fan can provide filter decay heat cooling air at the proper flowrate through the idle train. The valve allows isolation of the two trains when required for test purposes or when one train is down for maintenance.

K. Flow control valve - This is an air-operated butterfly valve which maintains the flowrate through the train at 4000 ft^3/min ±10% (4300 ft^3/min through the system when cooling the standby train). This valve is normally open and is controlled by the flow element in the discharge line to the 310-foot chimney.

L. Fan - The fans operate in parallel from a common system inlet plenum to provide flow through the two separate parallel trains. They are located downstream of the filters to minimize contamination during maintenance. Fan performance is discussed in Section 6.5.3.3. The fan performance curve is shown on Figure 6.5-3.

M. Backdraft damper - A backdraft damper is provided to ensure that reverse flow through the SBGTS filter train, which could spread contamination, will not occur. This damper acts as a check valve and closes whenever airflow into the exhaust fan occurs.

N. Outlet valve - This is a motor-operated butterfly valve which is normally closed. It opens automatically upon system initiation.

The SBGTS intake ducts can take suction from the reactor building ventilation system exhaust duct, the HPCI gland seal condenser exhaust, the ACAD system, the cooling air supply line, or from primary containment. The discharges from the two SBGTS trains are joined together and the discharge from the system is routed to the 310-foot chimney through a common line. Note: valves MO 2-7503 and 3-7503 are retained open with remote control removed.

SBGTS can be started manually, but is automatically initiated by a secondary containment isolation signal (as described in Section 6.2.3).

6.5.3.3 Design Evaluation

Figure 6.5-3 defines the head flow characteristics of the SBGTS fan. The performance of the fan under various exfiltration conditions is available from this curve. The head flow characteristic of the SBGTS fan was calculated using the polynomial method to determine the constants of the fan curve in order to equate exhaust flow as a function of the reactor building pressure. The pressure drops attributed to the components of the SBGTS are presented in Table 6.5-1. See Section 6.2.3 for an analysis of reactor building exfiltration.

When SBGTS is operating, the surrounding area can experience a very high dose rate. A temperature indicator and alarm is installed in the control room to monitor the temperature of the charcoal adsorber in the SBGTS and to advise the operator of limiting operating conditions. The location of this indicator also helps reduce the radiation exposure of operating personnel. The indicator setpoints (112°C to 117°C, or 233.6°F to 242°F), which are based on experimental and manufacturer's recommendations, are to ensure integrity of the charcoal adsorbers.

Shielded doors have been installed between the SBGTS trains and their respective control cabinets to isolate the cabinets from the harsh environment caused by the filters and adsorbers on the trains. These doors do not adversely affect the operation of existing equipment because the shields are classified Class I and are safety related. These doors ensure equipment will operate in a suitable environment.

SBGTS fans, heaters, and dampers are supplied by 480-V ESS buses, which receive auxiliary power during a loss of offsite power (LOOP). The motor control center (MCC) for Train A of the SBGTS is fed from bus 29 in Unit 2, and the MCC for Train B is fed from bus 39 in Unit 3. There is a divisional separation between Train A and Train B cables. In this way, the SBGTS is protected against the possibility of a single failure to either the Unit 2 or Unit 3 125-Vdc battery system, concurrent with a LOCA and LOOP in the other unit, rendering both trains of the system inoperable. Section 8.3 contains a description of the emergency power system.

Bus 29 is required for post-fire safe shutdown. The load added by the SBGTS MCC must be manually disconnected from bus 29 to protect safe shutdown equipment following a fire.

6.5.3.4 Testing and Inspection

The preoperational tests of the SBGTS included a test to demonstrate that the SBGTS can maintain a negative internal pressure in the reactor building at 1/4-in.H_2O. Subsequent tests also demonstrated the effectiveness of the SBGTS to perform its designed functions as specified in the Technical Specifications. Further information on preoperational and startup testing is contained in Chapter 14.

Pressure buildup caused by plugging of filters or adsorbers, or pressure loss caused by development of leaks or channels through or around filters and adsorbers, is indicated by local instrumentation and will lead to initiation of appropriate maintenance. Testing for clogging or leakage is performed periodically, as directed by the Technical Specifications.

The in-place efficiency of each HEPA filter is tested periodically with the DOP portable instrumentation. The testing must demonstrate at least 99% efficiency. Iodine removal efficiency of the charcoal adsorber is tested periodically by laboratory analysis of a test canister removed from the adsorber.

6.5.3.5 Instrumentation Requirements

The SBGTS system has instrumentation installed to support the testing outlined in Section 6.5.3.4. Differential pressure is monitored across the demister, rough prefilter, HEPA prefilter, activated charcoal bed, and HEPA afterfilter. Temperature is monitored before and after the electric heater, and before and after the activated charcoal adsorber bed. Humidity is locally indicated at the adsorber bed inlet. System flowrate is monitored at the flow control valves, at a flow element in the common discharge line and in the control room. Parameters which cause automatic initiation of the SBGTS, along with damper positions and fan operation, are monitored in the control room.

Table 6.5-1

PRESSURE DROPS FOR SBGTS EXHAUST TRAIN

System Components	Pressure Drop Corresponding to 4000 f^3/min (in $H_{\{2\}}O$)
Suction ductwork up to SBGTS	0.7
Pressure drop across SBGTS equipment	10.5[(1)]
Pressure drop for flow orifice	2.0
Discharge ductwork up to base of 310-foot chimney	2.0
Allowance for system head if ventilation air flowing in chimney	0.8
Total	16.0

Notes:

1. With clean filters this Delta-P is maintained by throttling suction dampers. As filters become dirty, dampers are opened to maintain 10.5 in $H_{\{2\}}O$. Dirty filters have a Delta-P allowance of 4.0 in $H_{\{2\}}O$.

6.6 INSERVICE INSPECTION OF CLASS 2 AND 3 COMPONENTS

A summarized inservice inspection program, including information on areas subject to examination, method of examination, and relief requests, is provided in the Dresden Station Inservice Inspection Plan. This section addresses inservice inspection (ISI) for ISI Class 2 and 3 components. ISI for Class 1 components is addressed in Section 5.2. Inservice inspection and testing of pumps and valves is discussed in Section 3.9.

The ISI program was developed in accordance with the requirements of 10 CFR 50.55a and the 1995 Edition with 1996 Addenda of the ASME Code Section XI. Where these rules were determined to be impractical, specific relief was requested in writing from the NRC. The NRC is authorized by 10 CFR 50.55a(g)(6)i to grant relief from the requirements of ASME Section XI upon making the necessary findings. Relief requests are included in the Dresden ISI Plan.

The ISI Plan is effective from January 20, 2003, through and including January 19, 2013, which represents the fourth 10-year interval of the ISI program for Dresden Station Units 2 and 3.

6.6.1 Components Subject to Examination

The construction permits for Dresden Units 2 and 3 were issued on January 10, 1966, and October 14, 1966, respectively. At that time, ASME Section III covered only pressure vessels, primarily nuclear reactor vessels, and associated piping up to and including the first isolation or check valve. Piping, pumps, and valves were built primarily to the rules of USAS B31.1, the Power Piping Standard, and so the station ISI program contains no ASME Section III Class 1, 2, or 3 designed systems. The system classifications used as a basis for the ISI program are based on the requirements given in 10 CFR 50.55a(g) and Regulatory Guide 1.26, Revision 3. These classifications were developed for the sole purpose of assigning the appropriate ISI requirements for water, steam, and radioactive waste containing components. Components within the reactor coolant pressure boundary (RCPB), as defined in 10 CFR 50.2, are designated ISI Class 1 as determined by 10 CFR 50.55 a, with the exceptions allowed by 10 CFR 50.55a(c). Other safety-related components are designated as ISI Class 2 or 3 in accordance with the guidelines of Regulatory Guide 1.26. Pursuant to 10 CFR 50.55a, Paragraph (a)(1), the ISI requirements of ASME Section XI are assigned to these components, within the constraints of existing plant design. The extent of the Class 1, 2, and 3 designations for systems or portions of systems subject to the ISI requirements are identified on the P&IDs.

6.6.2 Accessibility

Paragraphs (g)(1) and (g)(4) of 10 CFR 50.55a state that plants whose construction permits were issued prior to January 1, 1971, must meet the requirements of ASME Section XI to the extent practical within the limitations of design, component geometry, and material of construction of the components. Dresden's construction permit was issued prior to this date, and the as-built configuration of ISI Class 2 and Class 3 system components sometimes does not provide adequate clearance to conduct the required inspections. In these cases, specific relief requests are made as described previously.

6.6.3 Examination Techniques and Procedures

ASME Section XI, Tables IWC-2500-1, IWD-2500-1, and IWF-2500-1 specify the type of examination to be performed (visual, surface, or volumetric) within each examination category. Requirements for these examinations are given in ASME Section XI, Subarticle IWA-2200.

6.6.4 Inspection Intervals

As defined in ASME Section XI, Paragraph IWA-2432, the inspection interval is 10 years. The interval may be extended or decreased by as much as 1 year. However, such adjustments shall not cause successive intervals to be altered by more than 1 year from the original pattern of years.

The inspection frequencies for ISI Class 2 system components is that specified in ASME Section XI, Subarticle IWC-2400 and Table IWC-2500-1. The inspection frequencies for ISI Class 3 system components is specified in ASME Section XI, Subarticle IWD-2400 and Table IWD-2500-1. The inspection frequencies for ISI Class 2 and Class 3 system component supports is specified in ASME Section XI, Subarticle IWF-2400.

6.6.5 Examination Categories and Requirements

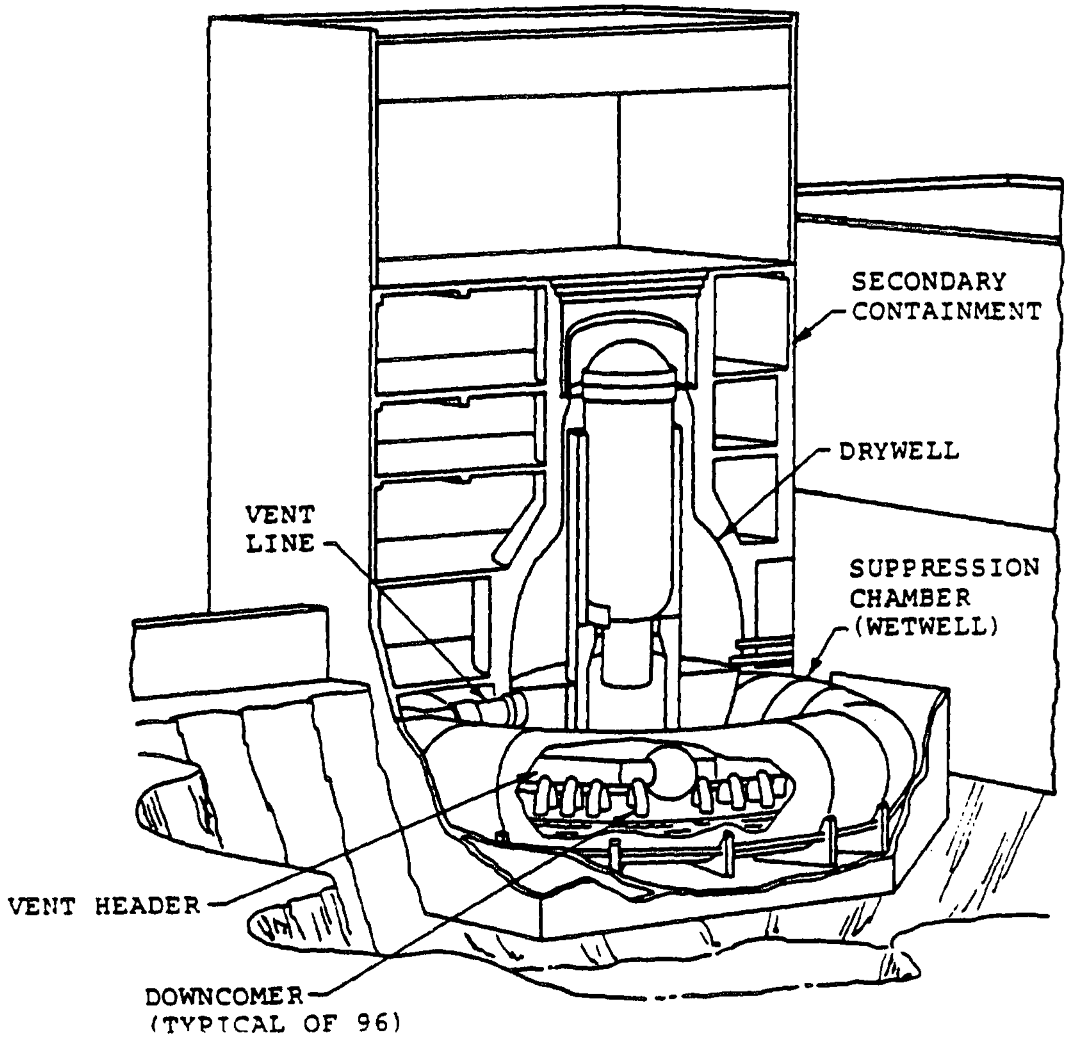
The Dresden ISI program is organized according to the inspection categories defined in ASME Section XI, Tables IWC-2500-1 for ISI Class 2, IWD-2500-1 for ISI Class 3, and IWF-2500-1 for ISI Class 2 and Class 3 component supports.

6.6.6 Evaluation of Examination Results

Flaws detected in ISI Class 2 component examinations are evaluated according to the requirements of ASME Section XI, Articles IWA-3000 and IWC-3000. Flaws detected in ISI Class 3 component examinations are evaluated according to the requirements of ASME Section XI, Articles IWA-3000 and IWD-3000. Flaws detected in ISI Class 2 or Class 3 component support examinations are evaluated according to the requirements of ASME Section XI, Articles IWA-3000 and IWF-3000. Repair/replacement activities for ISI Class 2 and Class 3 components and component supports are performed in compliance with ASME Section XI, Article IWA-4000.

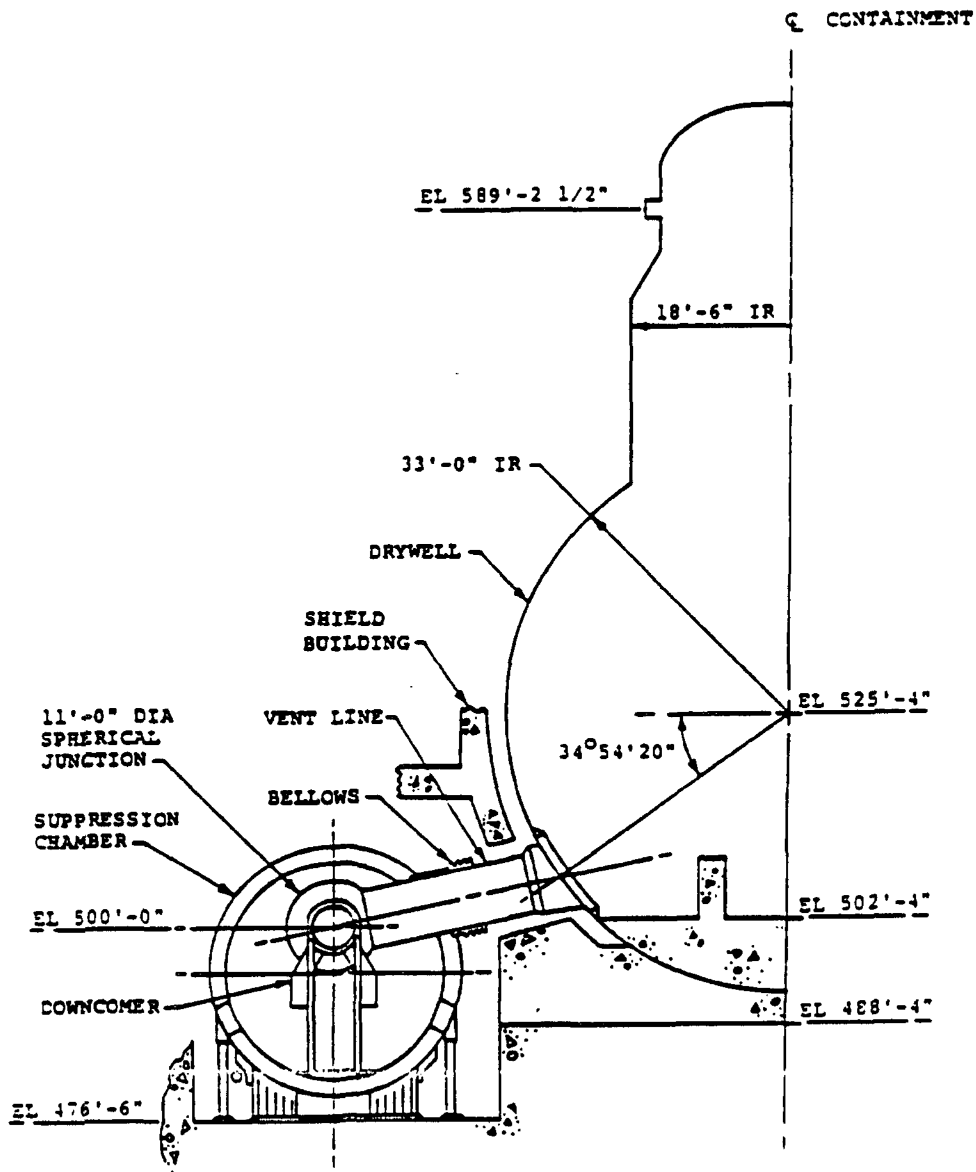
6.6.7 System Pressure Tests

Class 2 systems are pressure tested in accordance with ASME Section XI, Article IWA-5000 and Article IWC-5000. Class 3 systems are pressure tested according to ASME Section XI, Article IWA-5000 and Article IWD-5000.



1. THE DRYWELL AND SUPPRESSION CHAMBER FORM THE PRIMARY CONTAINMENT.

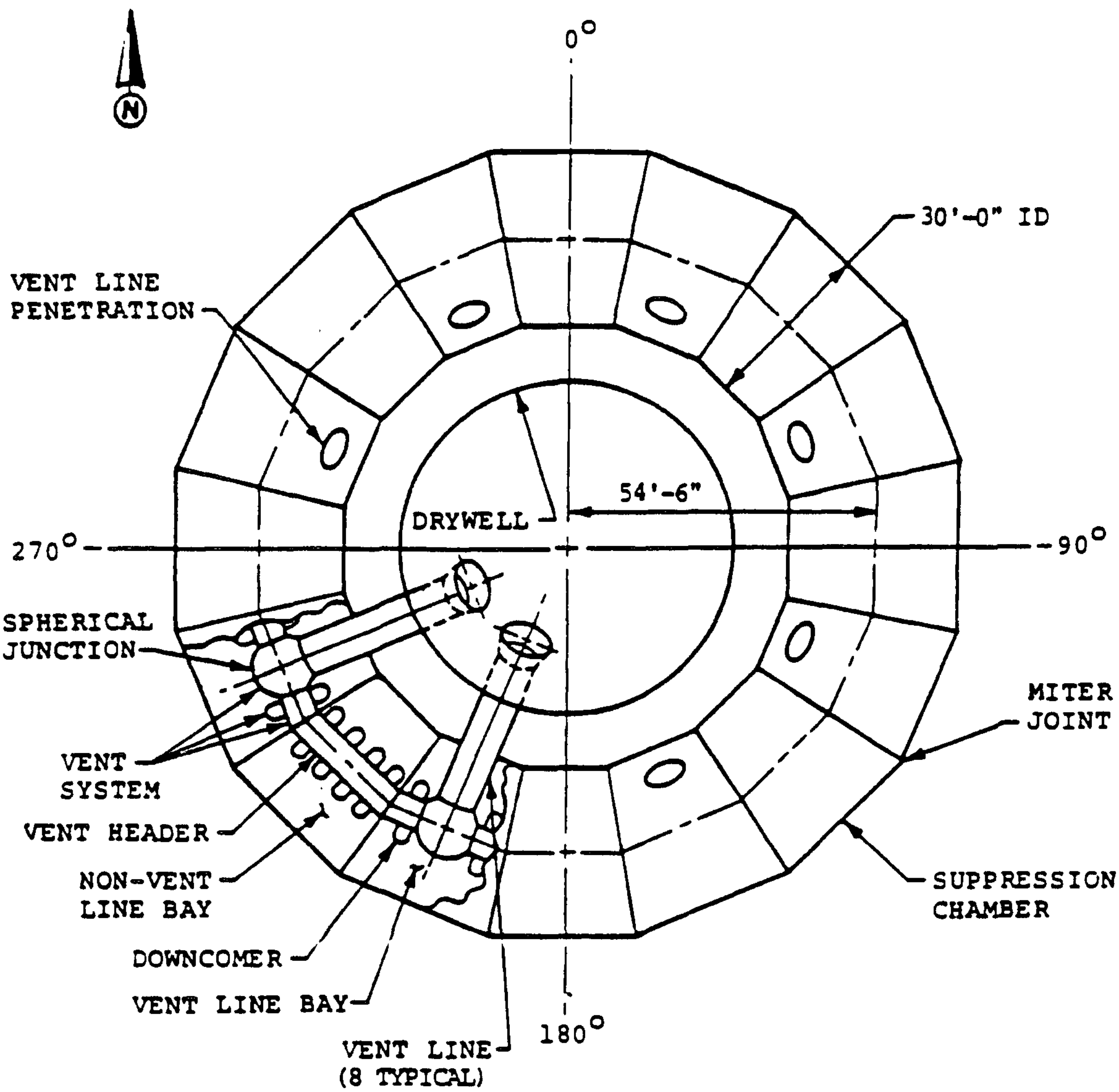
DRESDEN STATION UNITS 2 & 3
GENERAL ARRANGEMENT OF THE CONTAINMENT SYSTEMS
FIGURE 6.2-1



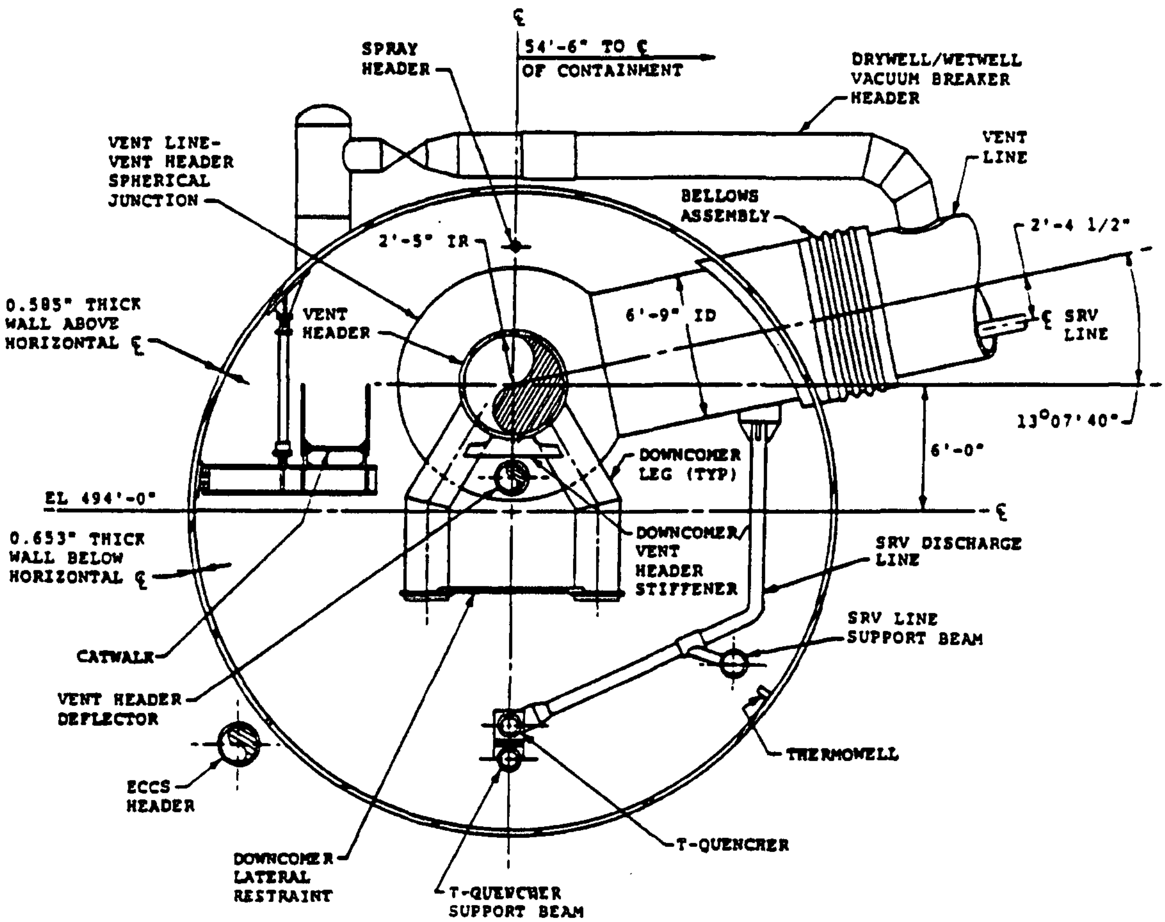
DRESDEN STATION
UNITS 2 & 3

ELEVATION VIEW OF CONTAINMENT

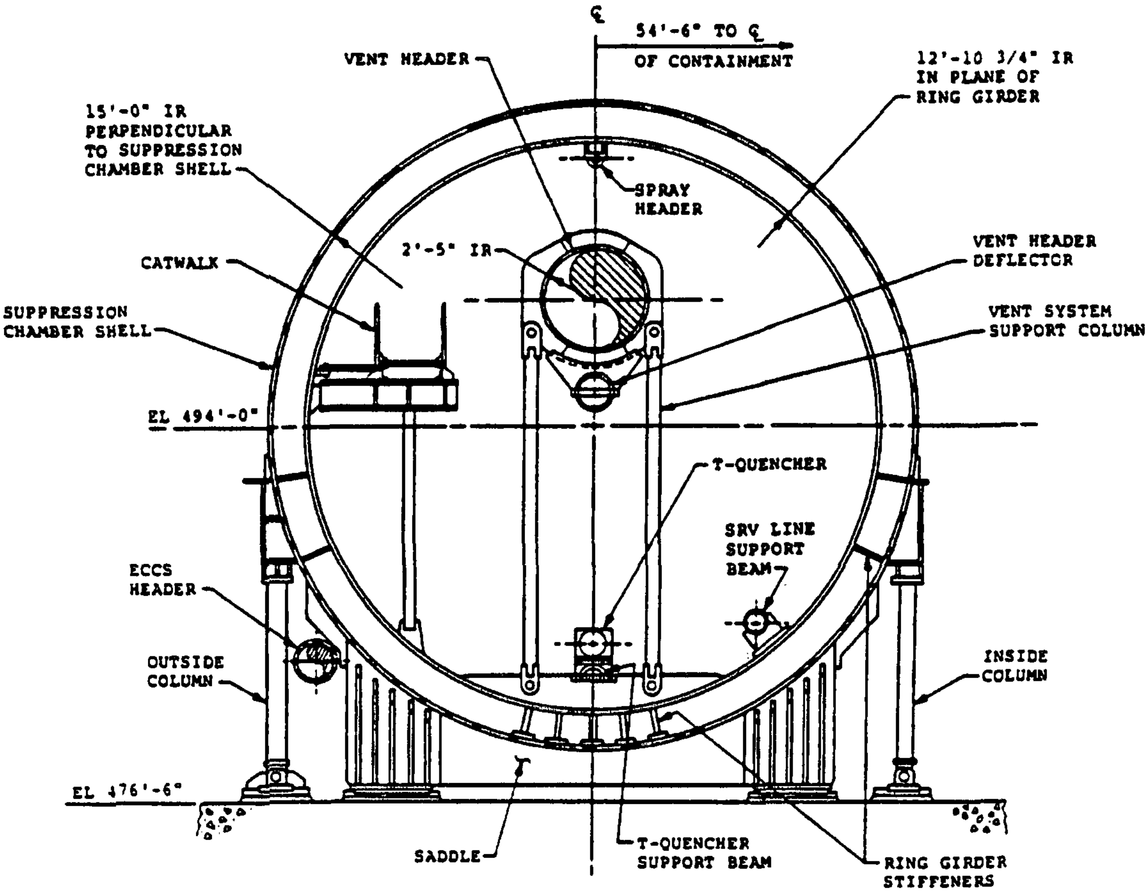
FIGURE 6.2-2



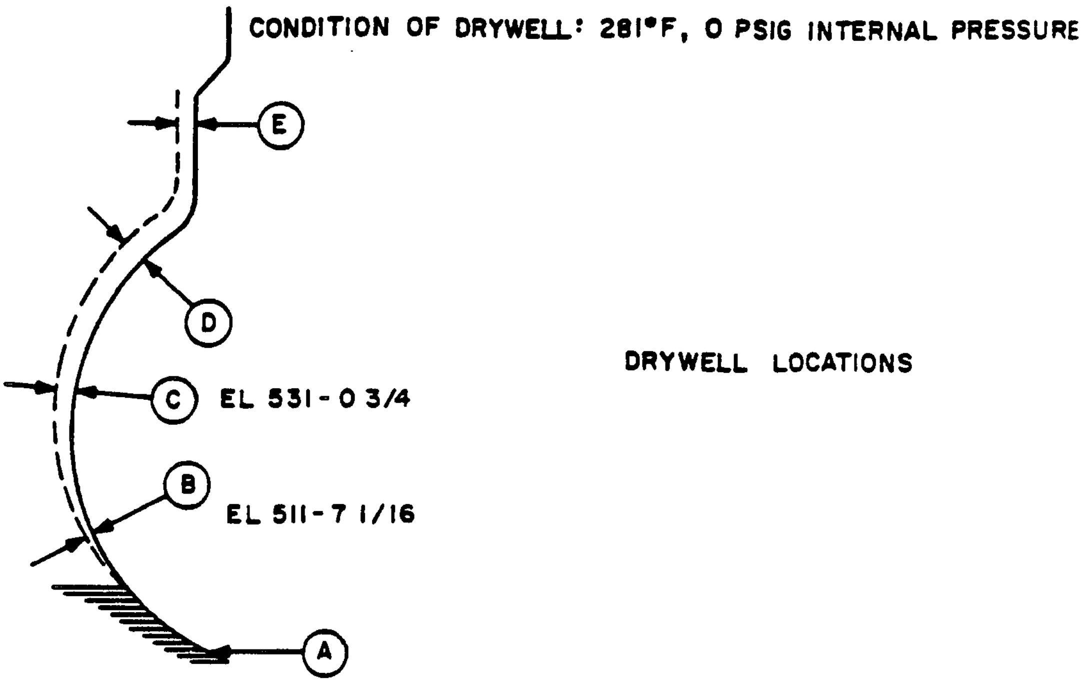
DRESDEN STATION UNITS 2 & 3
PLAN VIEW OF CONTAINMENT
FIGURE 6.2-3



DRESDEN STATION UNITS 2 & 3
SUPPRESSION CHAMBER SECTION - MIDBAY VENT LINE BAY
FIGURE 6.2-4



DRESDEN STATION UNITS 2 & 3
SUPPRESSION CHAMBER SECTION - MITER JOINT
FIGURE 6.2-5



LOCATION	(a) RESULTANT THERMAL GROWTH (INCHES)	(b) ALLOWABLE LOADING (psi)*	(c) RESULTANT LOADING (psi)	(d) DESIGN MARGIN SAFETY FACTOR
A.	0.00	1.55	0.0	-
B.	0.58	1.57	0.7	2.2
C.	0.80	3.05	0.8	3.8
D.	0.99	3.84	1.0	3.8
E.	0.33**	2.77	0.6	4.6

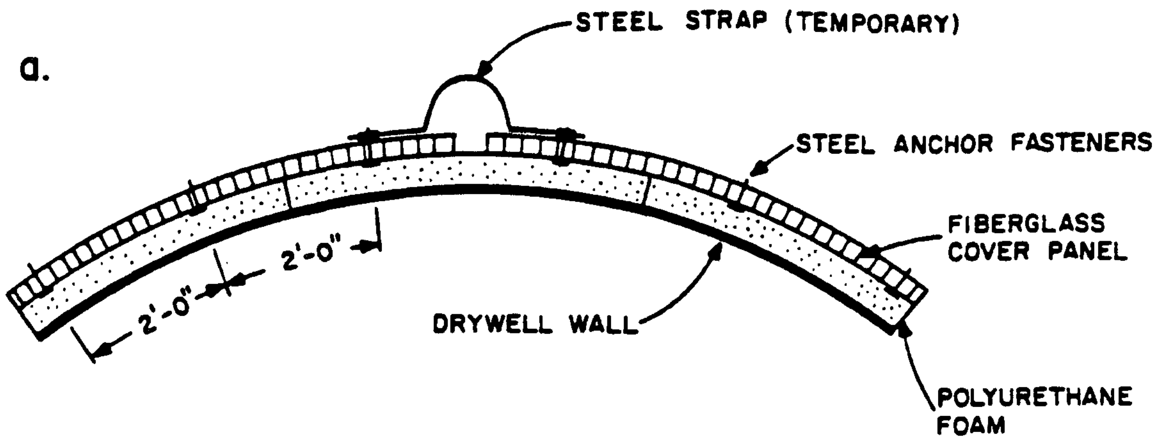
* CODE ALLOWABLE EXTERNAL UNIFORM LOADING ON DRYWELL SHELL IN EXCESS OF A 2-PSI ALLOWANCE MADE FOR GAS PRESSURE (-2 PSIG PRESSURE IN DRYWELL)

** RADIAL GROWTH ONLY. THE VERTICAL GROWTH OF THE CYLINDRICAL PORTION OF THE DRYWELL RESULTS IN A SLIP/SHEAR IN THE POLYURETHANE FOAM WHICH INCREASES THE LOADING ON THE SHELL BY A NEGLIGIBLE AMOUNT.

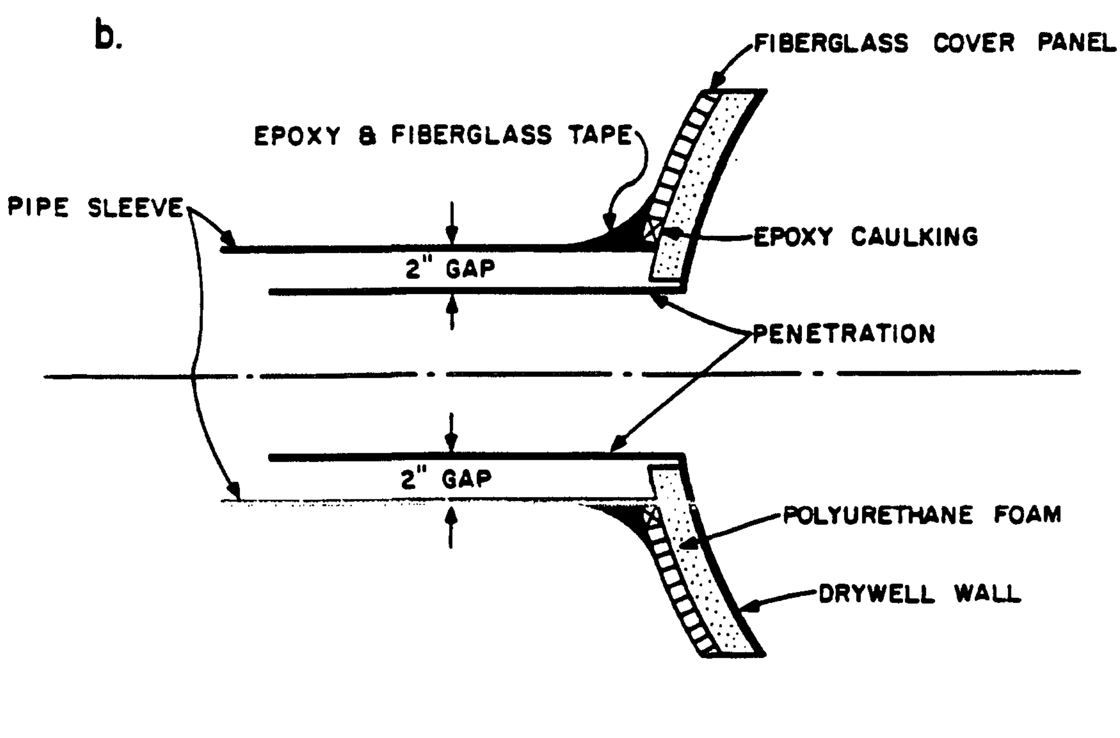
DRESDEN STATION
UNITS 2 & 3

DRYWELL THERMAL EXPANSION

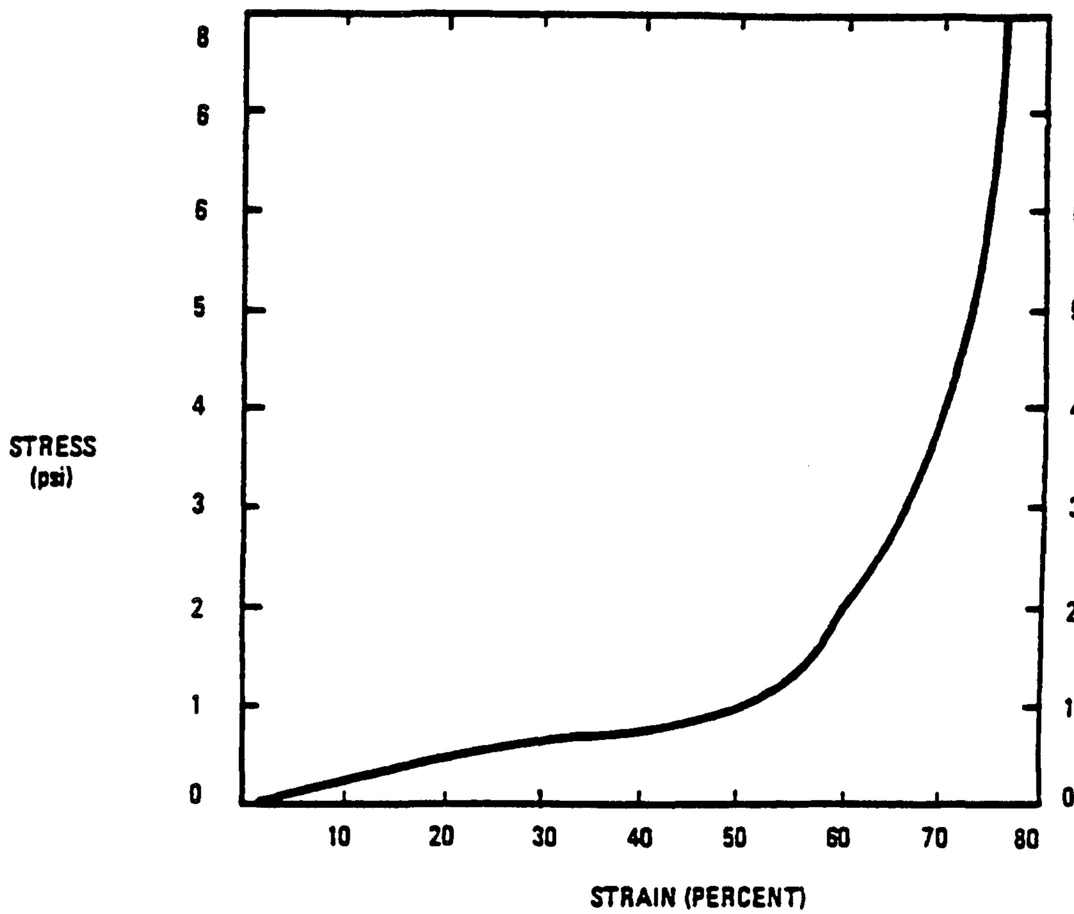
FIGURE 6.2-6



TYPICAL SECTION - SHOWING TEMPORARY STRAP



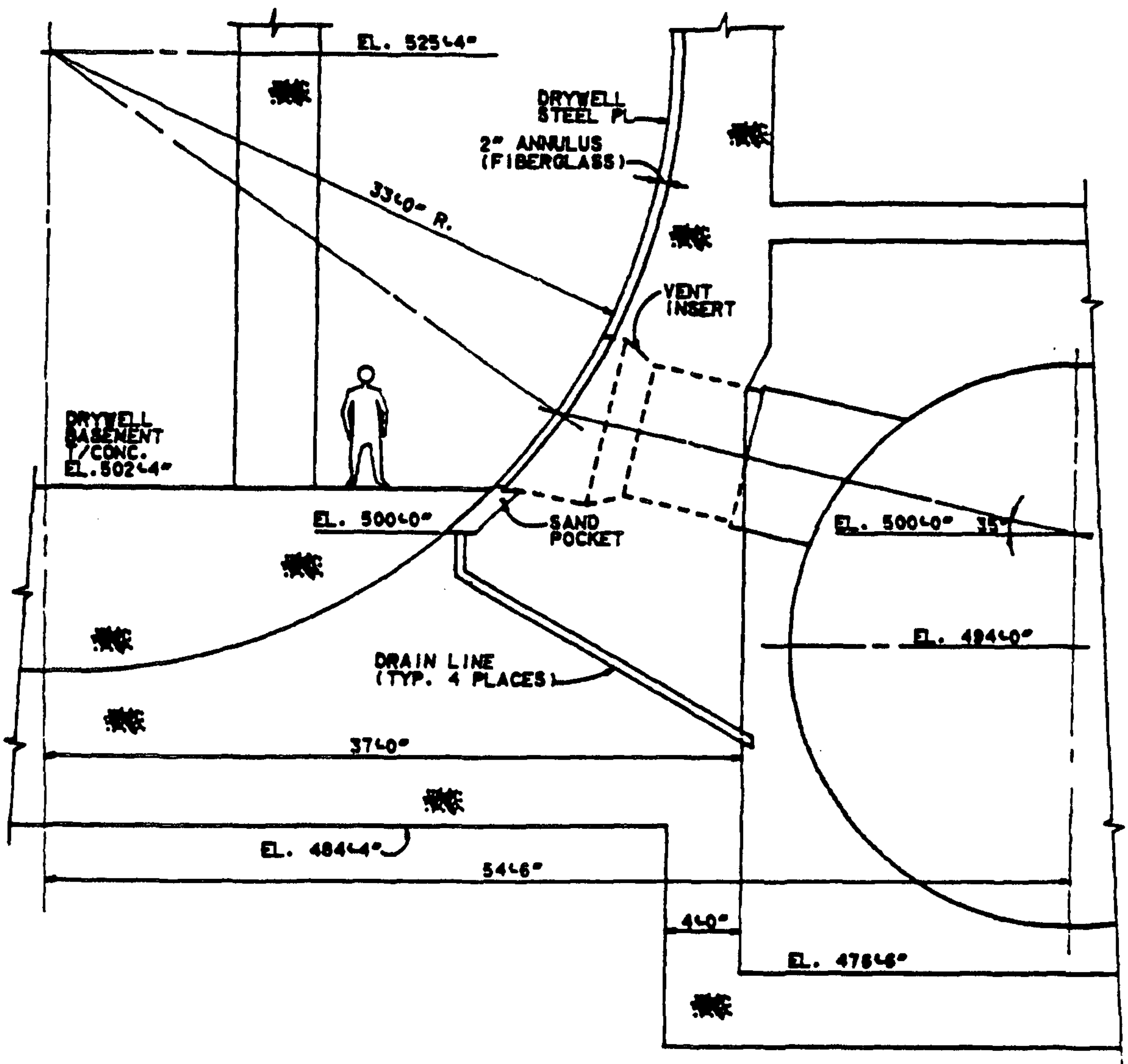
DRESDEN STATION UNITS 2 & 3
TYPICAL PENETRATION JOINT
FIGURE 6.2-7



DRESDEN STATION
UNITS 2 & 3

RESILIENT CHARACTERISTICS OF POLYURETHANE

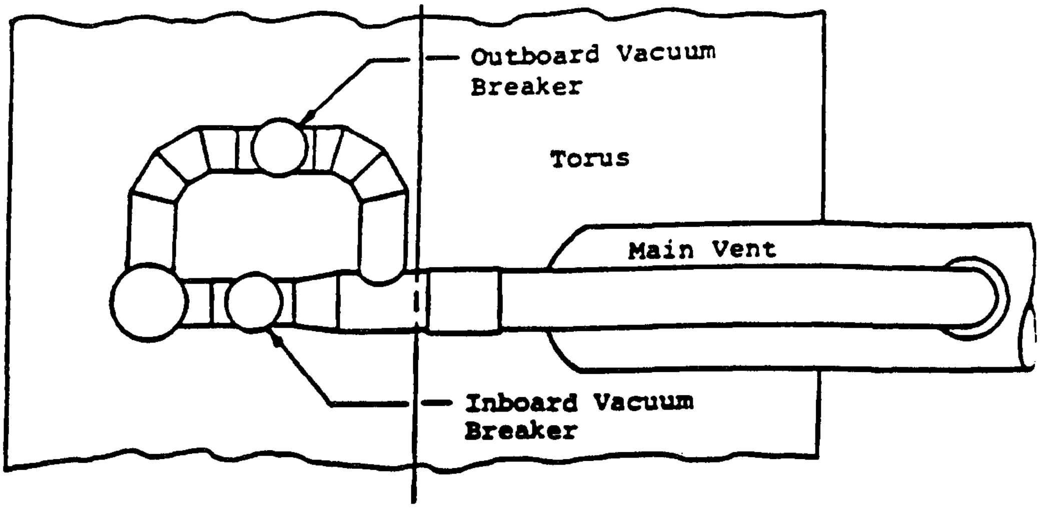
FIGURE 6.2-8



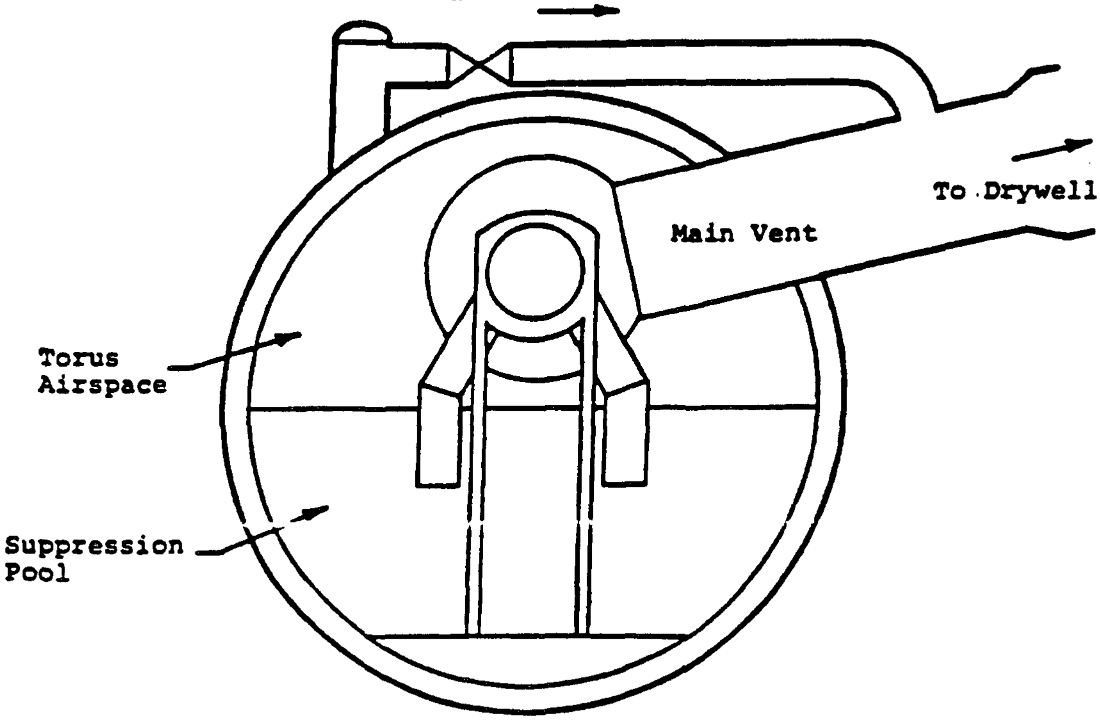
DRESDEN STATION
UNITS 2 & 3

CONTAINMENT SAND POCKET AND SAND POCKET DRAIN SYSTEM

FIGURE 6.2-9

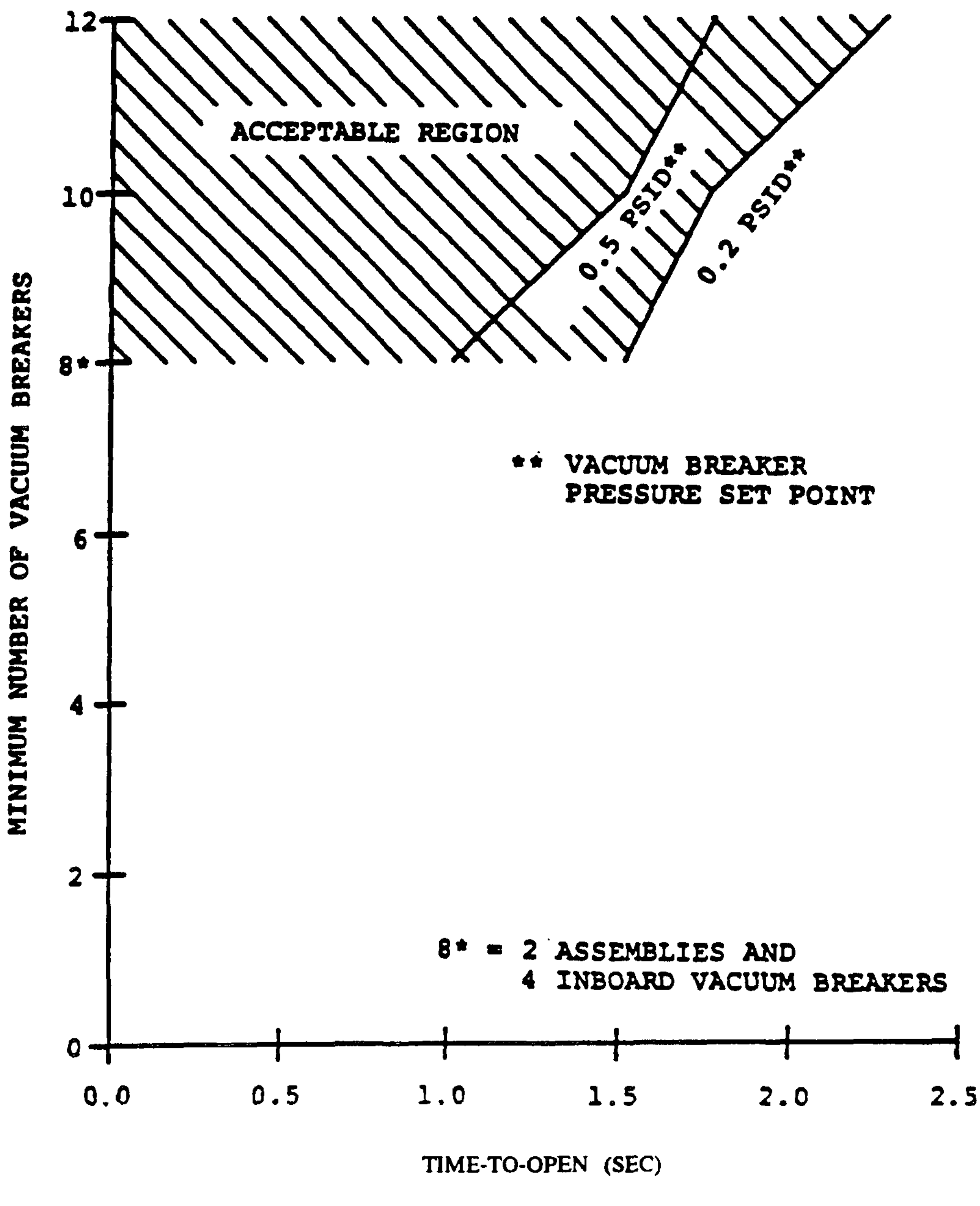


Vacuum Breaker Assembly - Plan View



Vacuum Breaker Assembly Location - Elevation

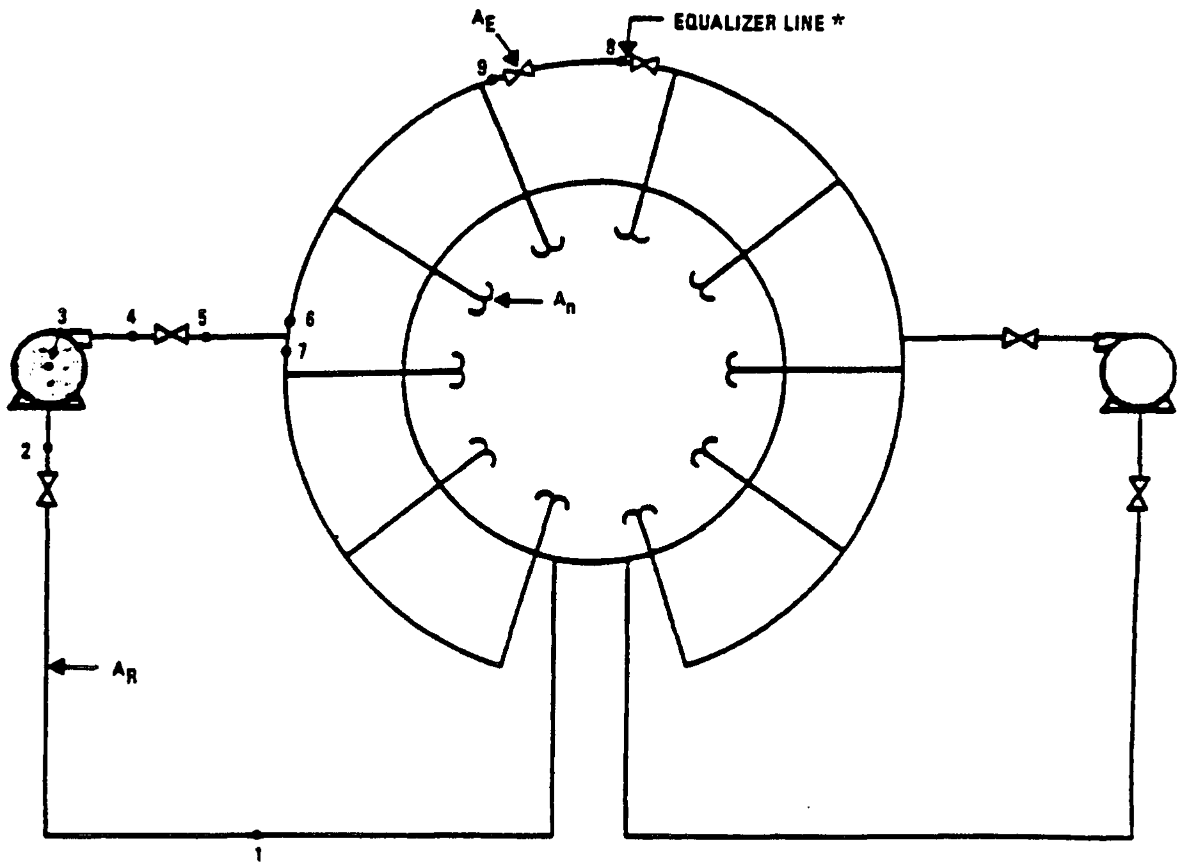
DRESDEN STATION UNITS 2 & 3
VACUUM BREAKER ASSEMBLY
FIGURE 6.2-10



DRESDEN STATION
UNITS 2 & 3

VACUUM BREAKER SIZING REQUIREMENTS

FIGURE 6.2-11



A_R = Flow area in recirculation line

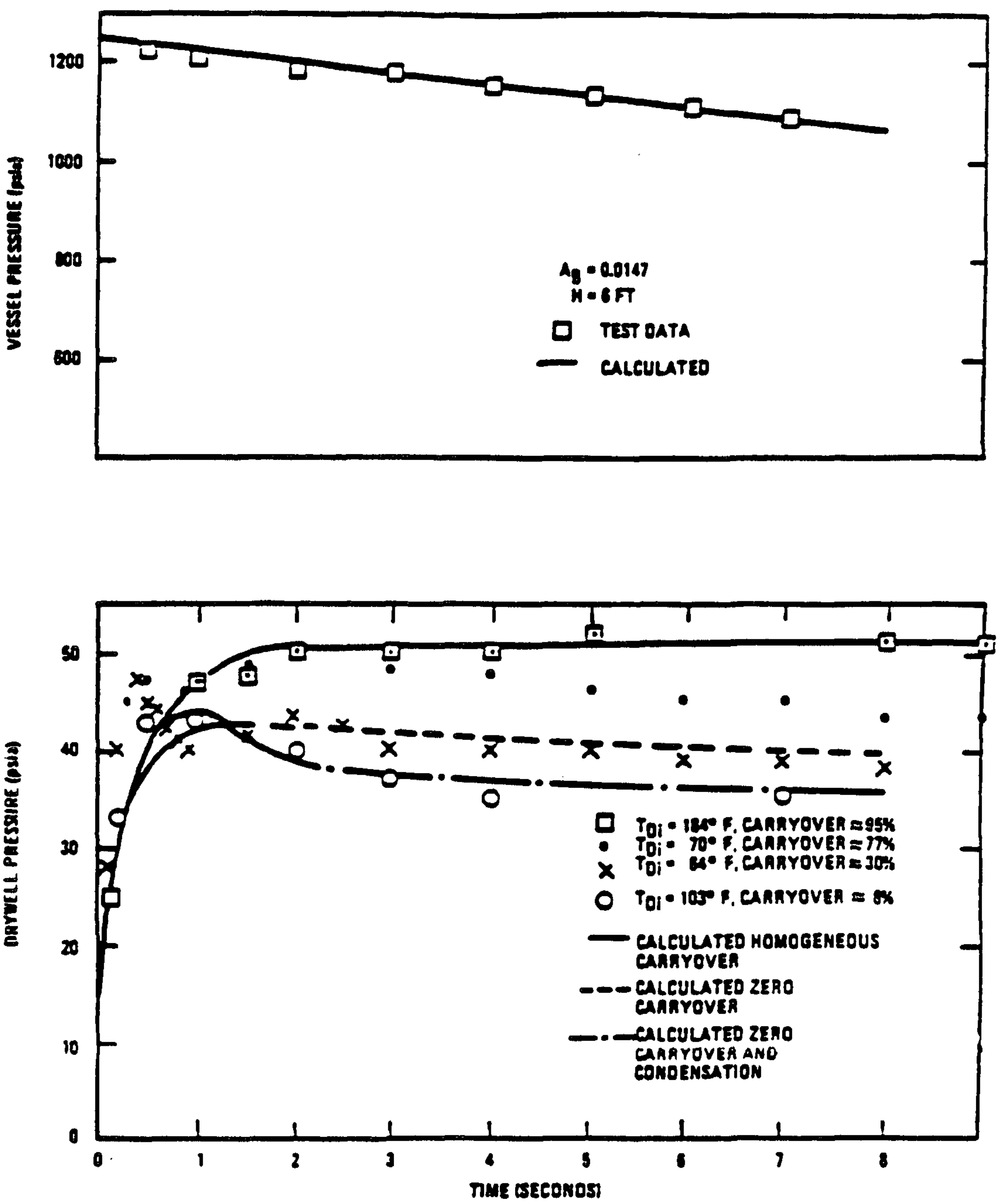
A_E = Flow area through equalizer line valve

A_n = Flow area of a jet pump nozzle

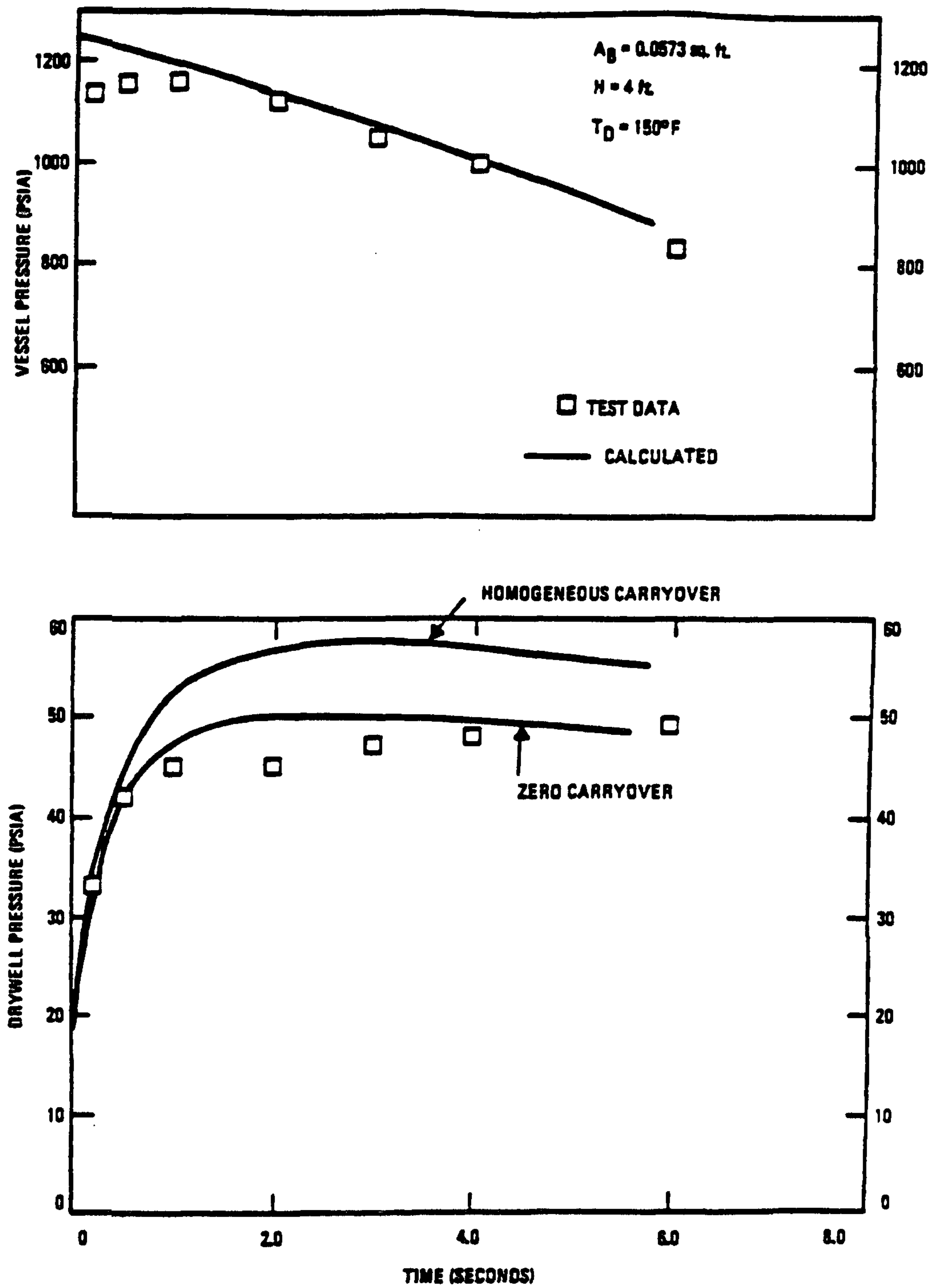
N = Number of jet pumps per header

*The equalizer line was removed on Unit 3 during the 1985-86 Recirculation Pipe Replacement Outage.

DRESDEN STATION UNITS 2 & 3
RECIRCULATION LINE BREAK - ILLUSTRATION
FIGURE 6.2-14



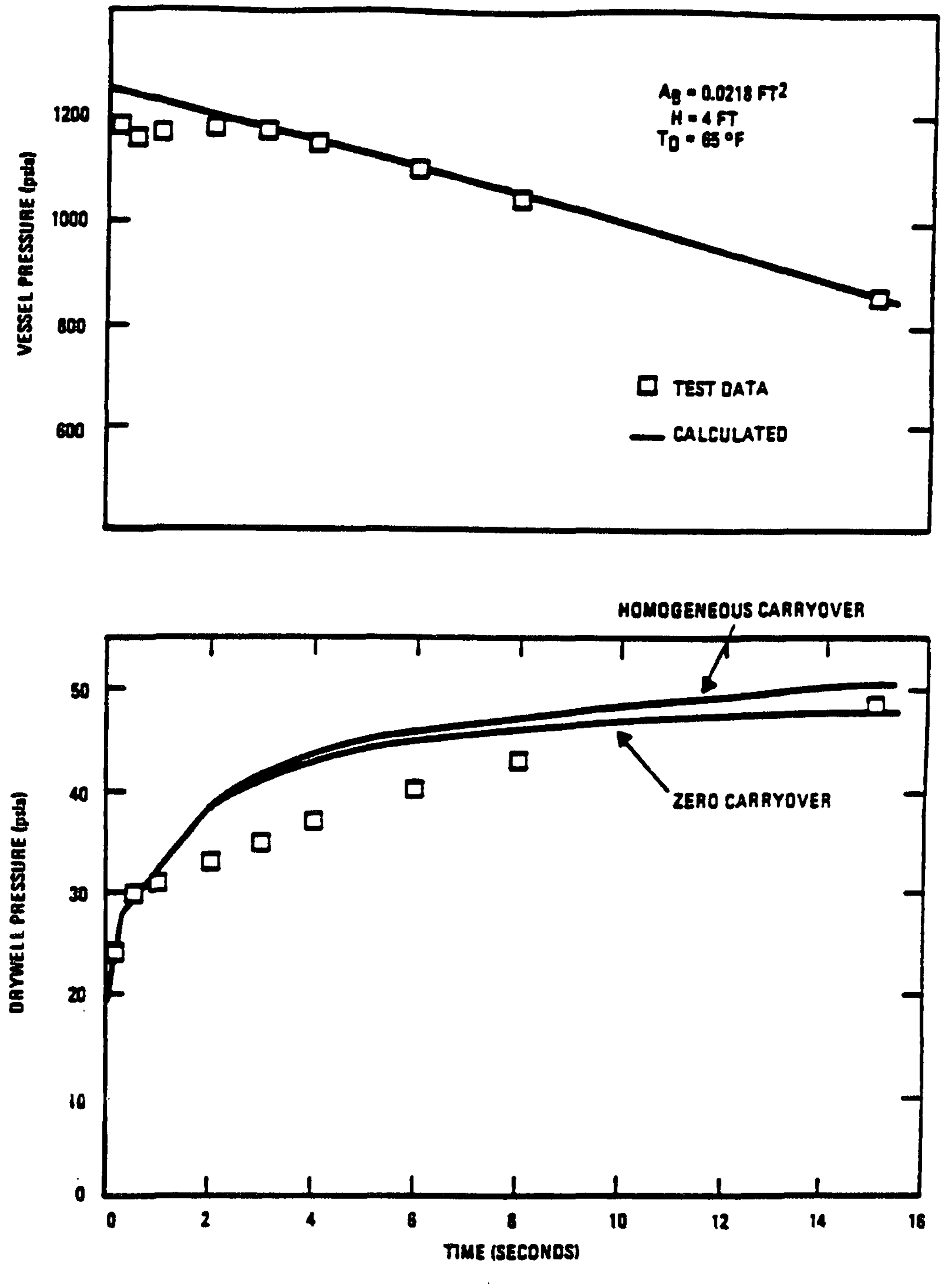
DRESDEN STATION UNITS 2 & 3
PRESSURE RESPONSE -CALCULATIONS AND MEASUREMENTS
FIGURE 6.2-15



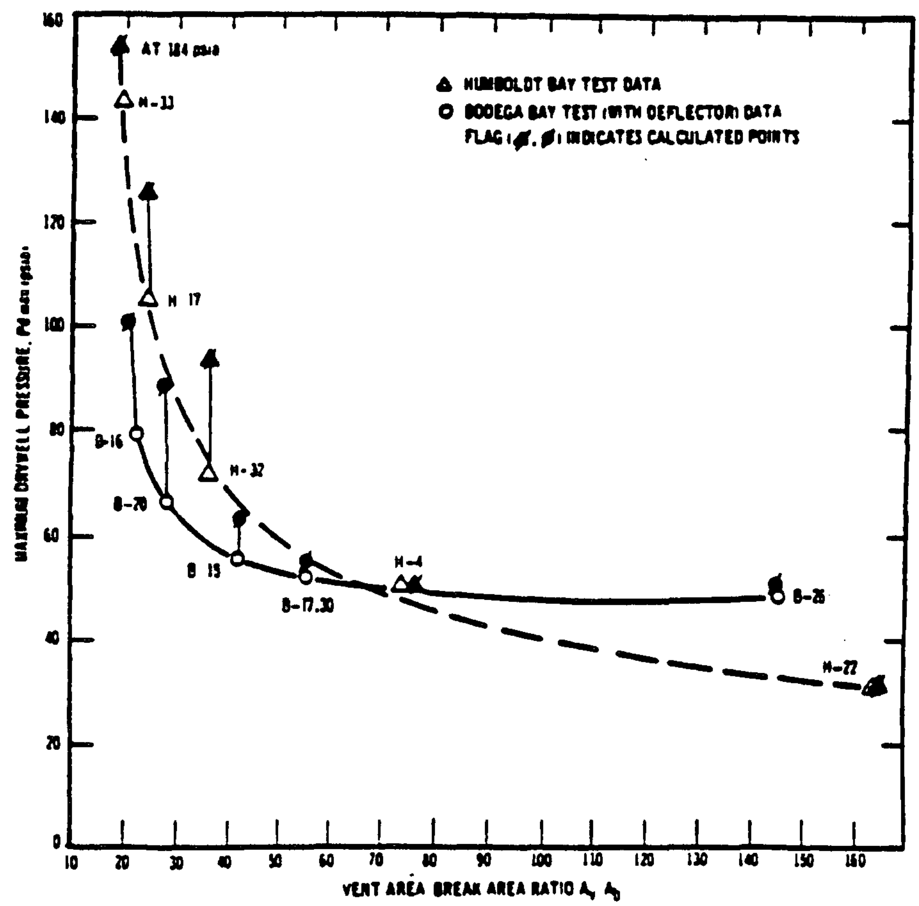
DRESDEN STATION
UNITS 2 & 3

BODEGA BAY TESTS - VESSEL PRESSURE & DRYWELL PRESSURE FOR BREAK AREA OF 0.0573 ft²

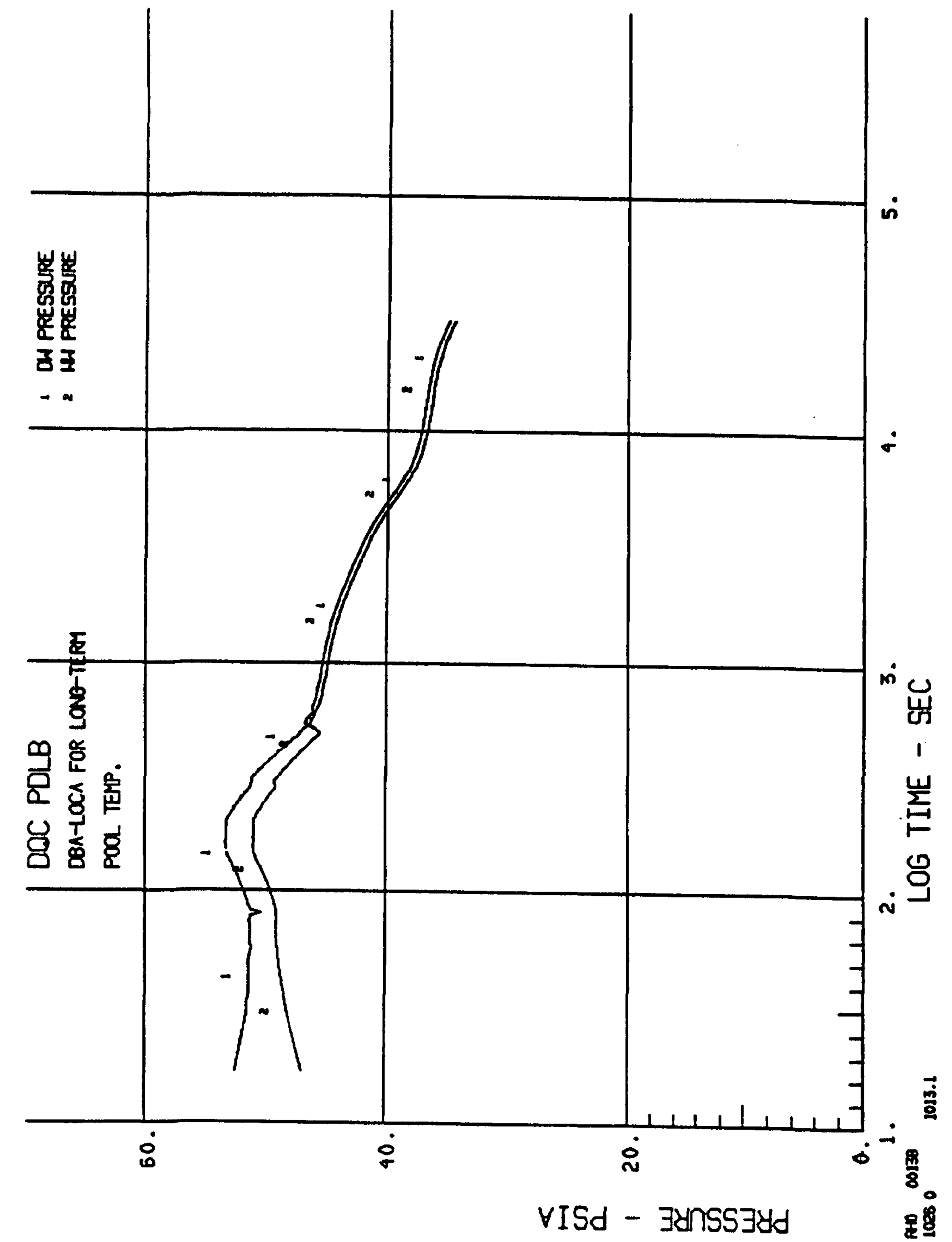
FIGURE 6.2-16



DRESDEN STATION UNITS 2 & 3
BODEGA BAY TESTS - VESSEL PRESSURE & DRYWELL PRESSURE FOR BREAK AREA OF 0.0218 ft^2
FIGURE 6.2-17



DRESDEN STATION UNITS 2 & 3
COMPARISON OF CALCULATED AND MEASURED PEAK DRYWELL PRESSURE
FIGURE 6.2-18

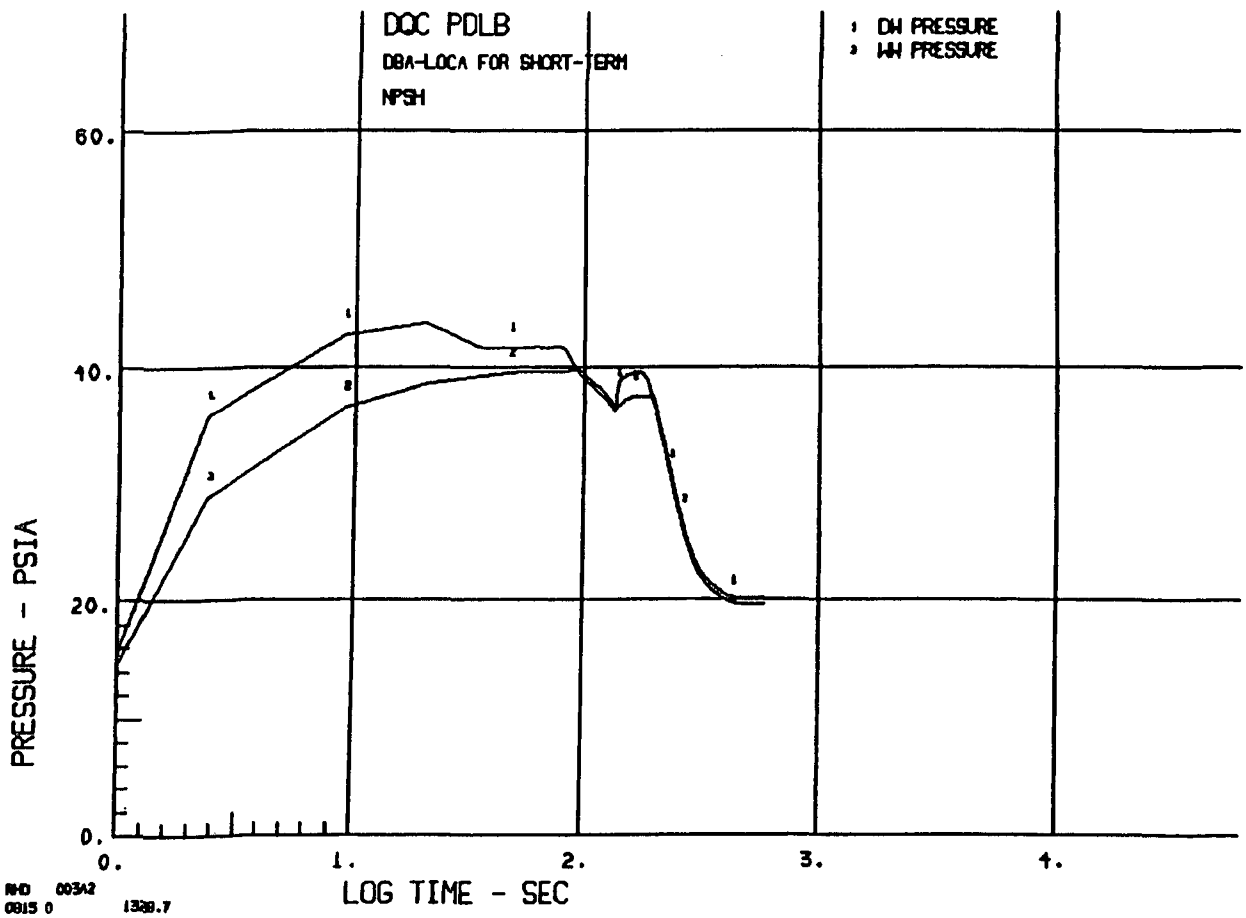


REVISION 5, JANUARY 2003

DRESDEN STATION
UNITS 2 & 3

LONG-TERM CONTAINMENT PRESSURE RESPONSE TO DBA-LOCA FOR DRESDEN (AT 2957 MWt)

FIGURE 6.2-19A



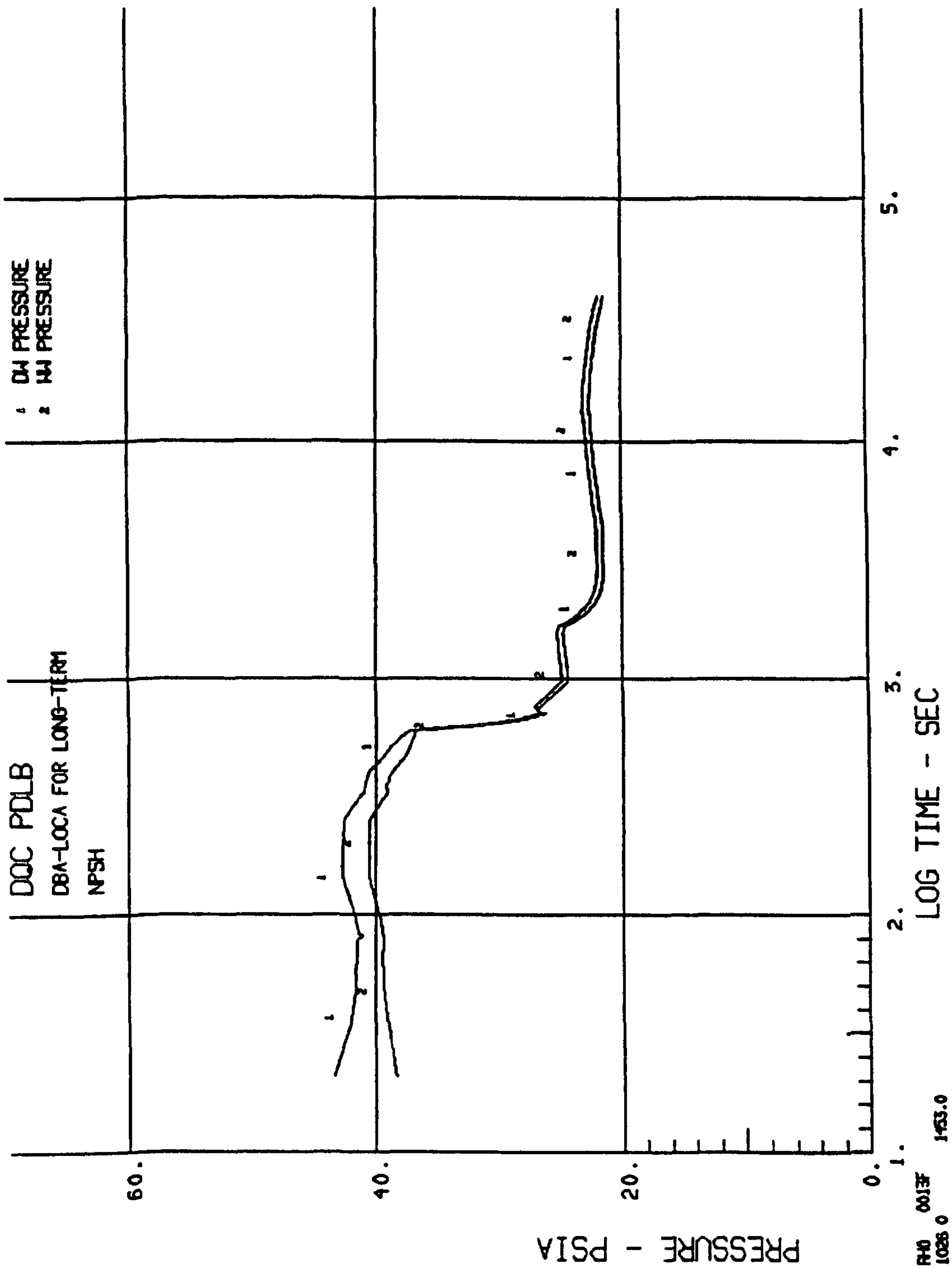
REVISION 5, JANUARY 2003

DRESDEN STATION
UNITS 2 & 3

SHORT-TERM CONTAINMENT PRESSURE RESPONSE (FOR NPSH) TO DBA-LOCA FOR DRESDEN

FIGURE 6.2-19B

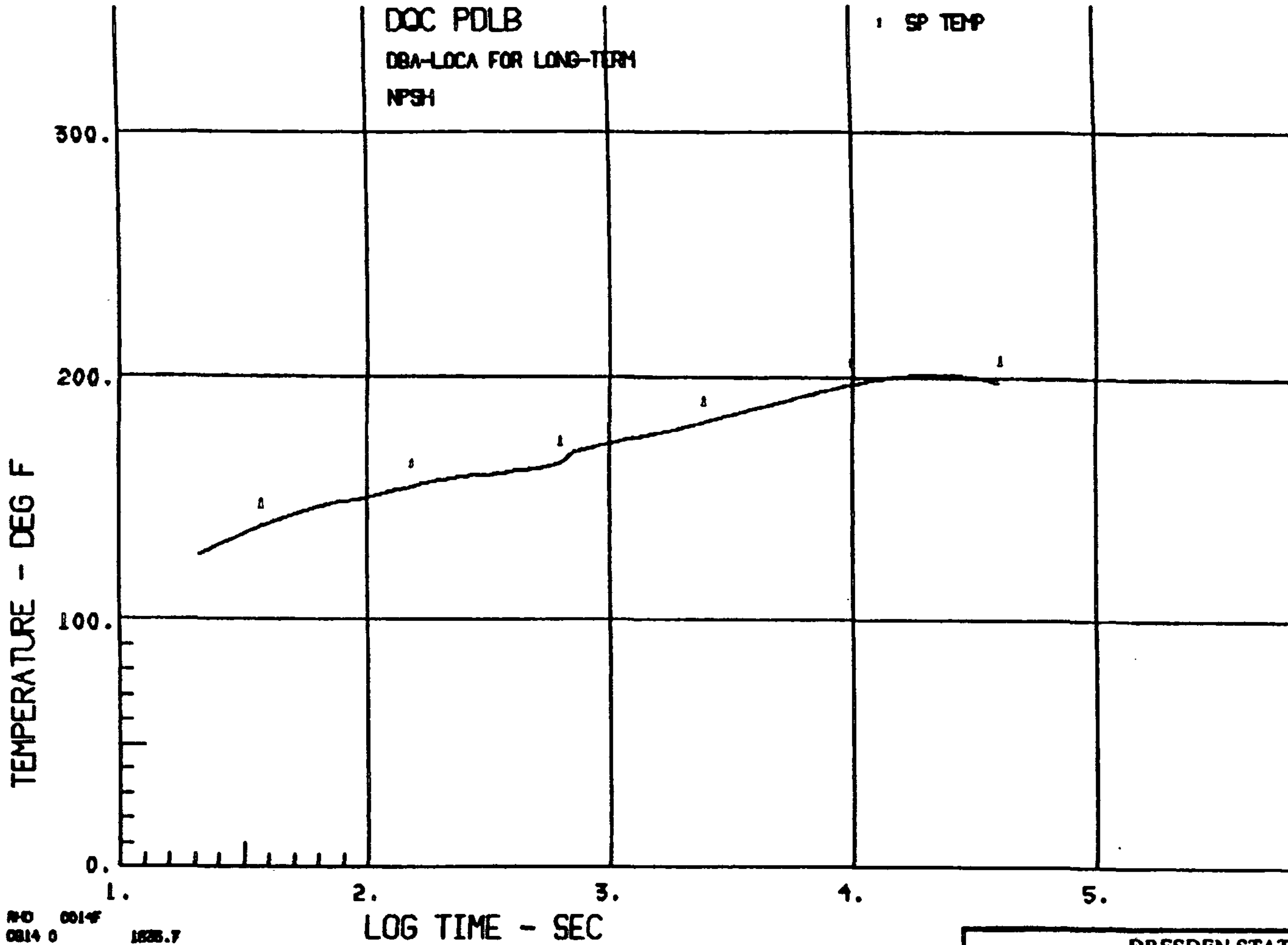
REVISION 5
JANUARY 2003



DRESDEN STATION
UNITS 2 & 3

LONG-TERM CONTAINMENT PRESSURE RESPONSE
(FOR NPSH) TO DBA-LOCA FOR DRESDEN

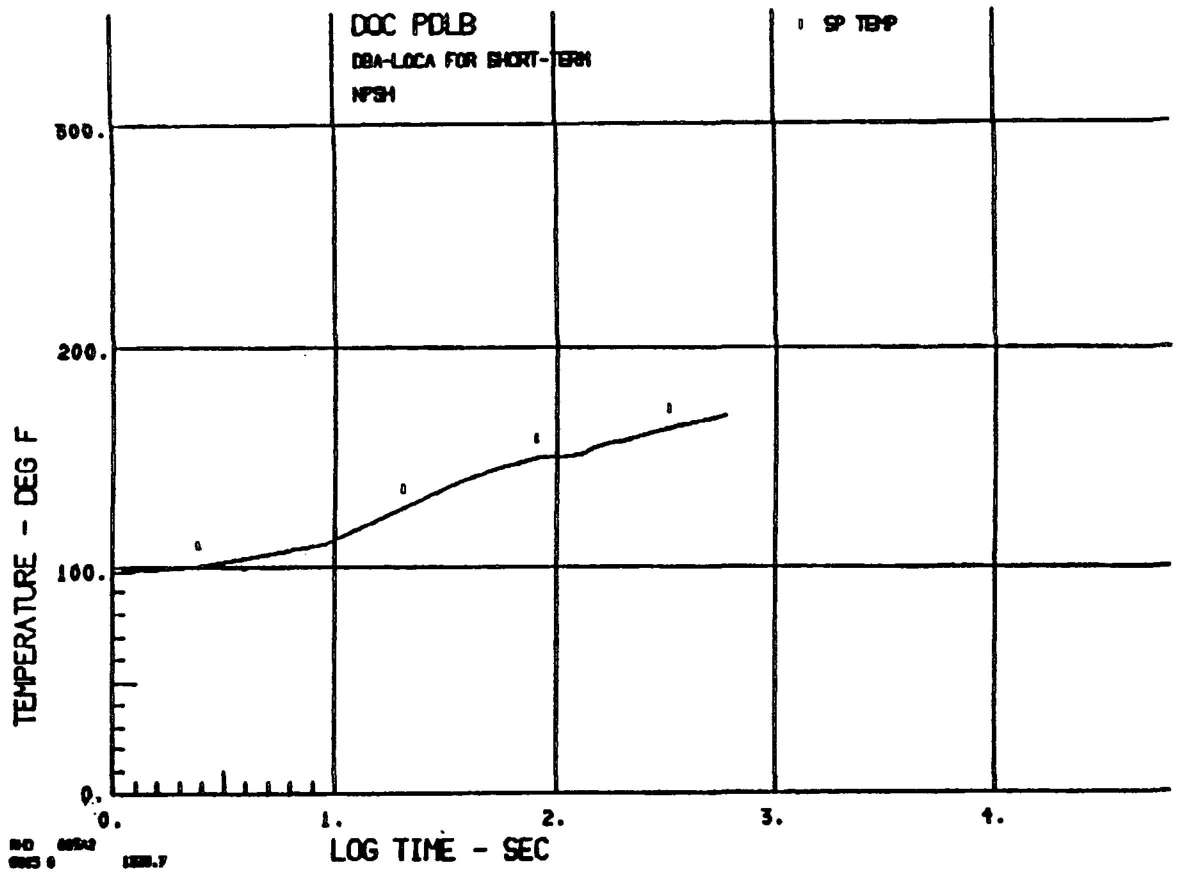
FIGURE 6.2-19C



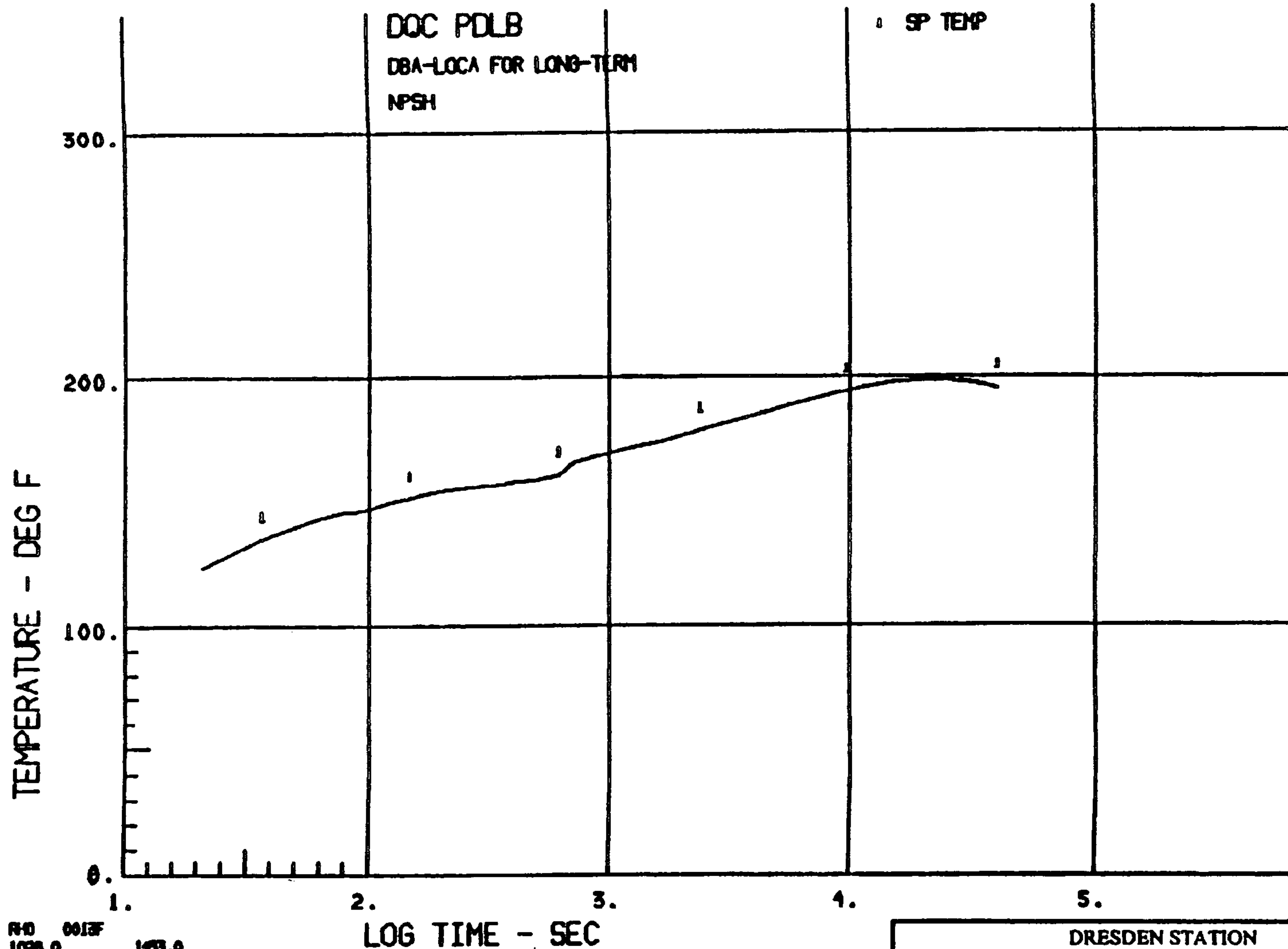
DRESDEN STATION
UNITS 2 & 3

LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE TO DBA-LOCA AT 2957 MWT

FIGURE 6.2-20A
REVISION 5, JANUARY 2003



DRESDEN STATION UNITS 2 & 3
SHORT-TERM SUPPRESSION POOL TEMPERATURE RESPONSE (FOR NPSH) TO DBA-LOCA FOR DRESDEN
FIGURE 6.2-20B REVISION 5, JANUARY 2003



DRESDEN STATION
UNITS 2 & 3

LONG-TERM SUPPRESSION POOL TEMPERATURE RESPONSE (FOR NPSH) TO DBA-LOCA FOR DRESDEN

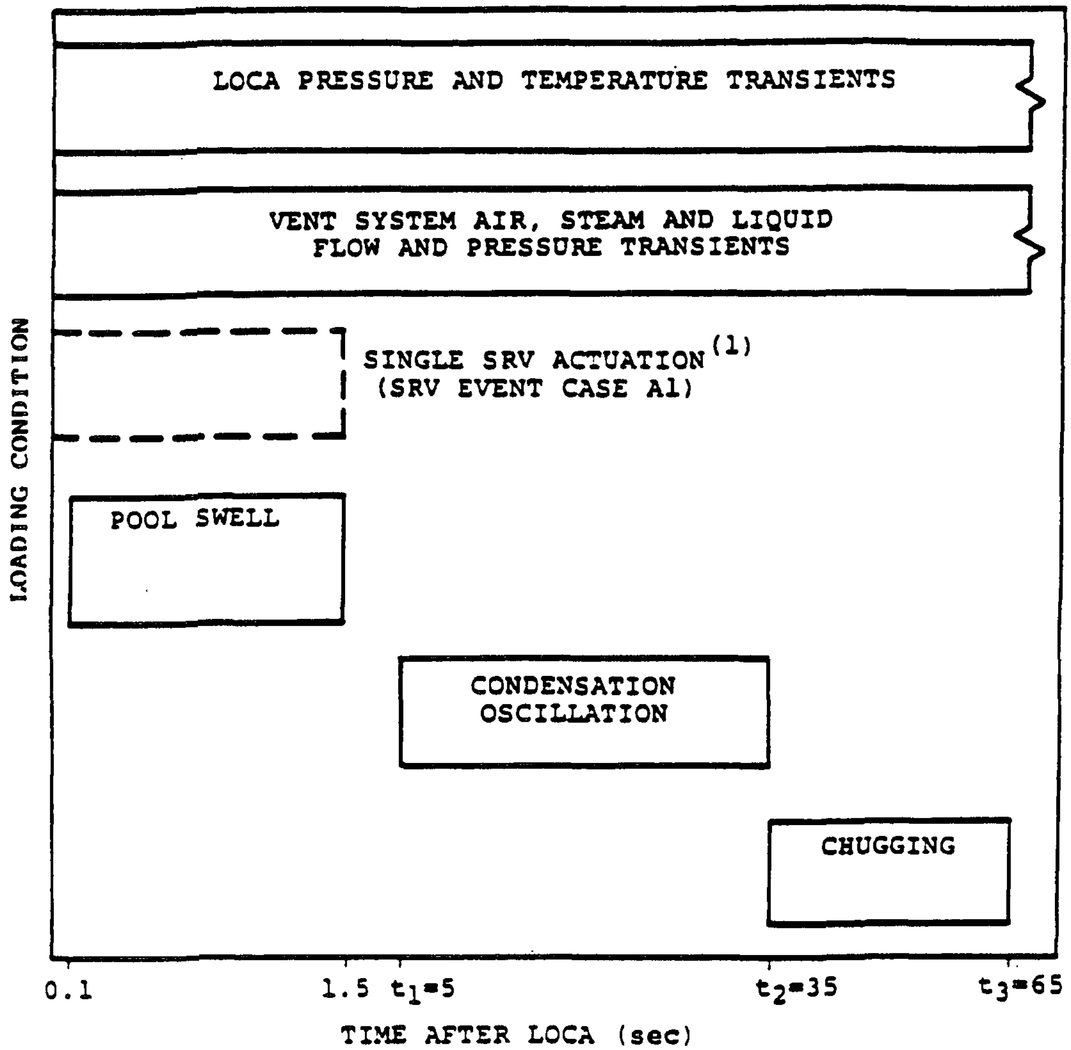
FIGURE 6.2-20C
REVISION 5, JANUARY 2003

PHENOMENON	POTENTIAL DYNAMIC LOADING CONDITION
PIPE BREAK - LOCA	• COMPRESSION WAVE • INCREASE IN VENT SYSTEM STATIC PRESSURE • START OF VENT SYSTEM THERMAL TRANSIENT
DOWNCOMERS CLEARED OF WATER AIR FLOW BEGINS	• WATER-JET LOADS ON TORUS AND SUBMERGED STRUCTURES • VENT SYSTEM REACTION LOADS • BUBBLE LOAD ON TORUS - DOWNLOAD • DOWNCOMER AIR-CLEARING LOAD
BULK POOL SWELL	• IMPACT LOADS • TORUS COMPRESSION - UPLOAD • DRAG LOADS ON SUBMERGED STRUCTURES
POOL BREAKTHROUGH	
FROTH POOL SWELL	• FROTH IMPINGEMENT LOADS
POOL FALLBACK	• FALLBACK LOADS
CONTINUED AIR/STEAM FLOW	• TORUS PRESSURIZATION • POST-SELL WAVE LOADS • FLOW REACTION LOADS ON VENT SYSTEM
CONTINUED STEAM FLOW	• PRESSURE OSCILLATIONS • DOWNCOMER LOADS
BLOWDOWN OVER	
ECCS REFLOOD	• NEGATIVE PRESSURE ON VENT SYSTEM
LONG-TERM HEATUP	• THERMAL LOADS • SECOND PRESSURE PEAK IN TORUS

DRESDEN STATION
UNITS 2 & 3

LOCA SEQUENCE OF PRIMARY EVENTS

FIGURE 6.2-21

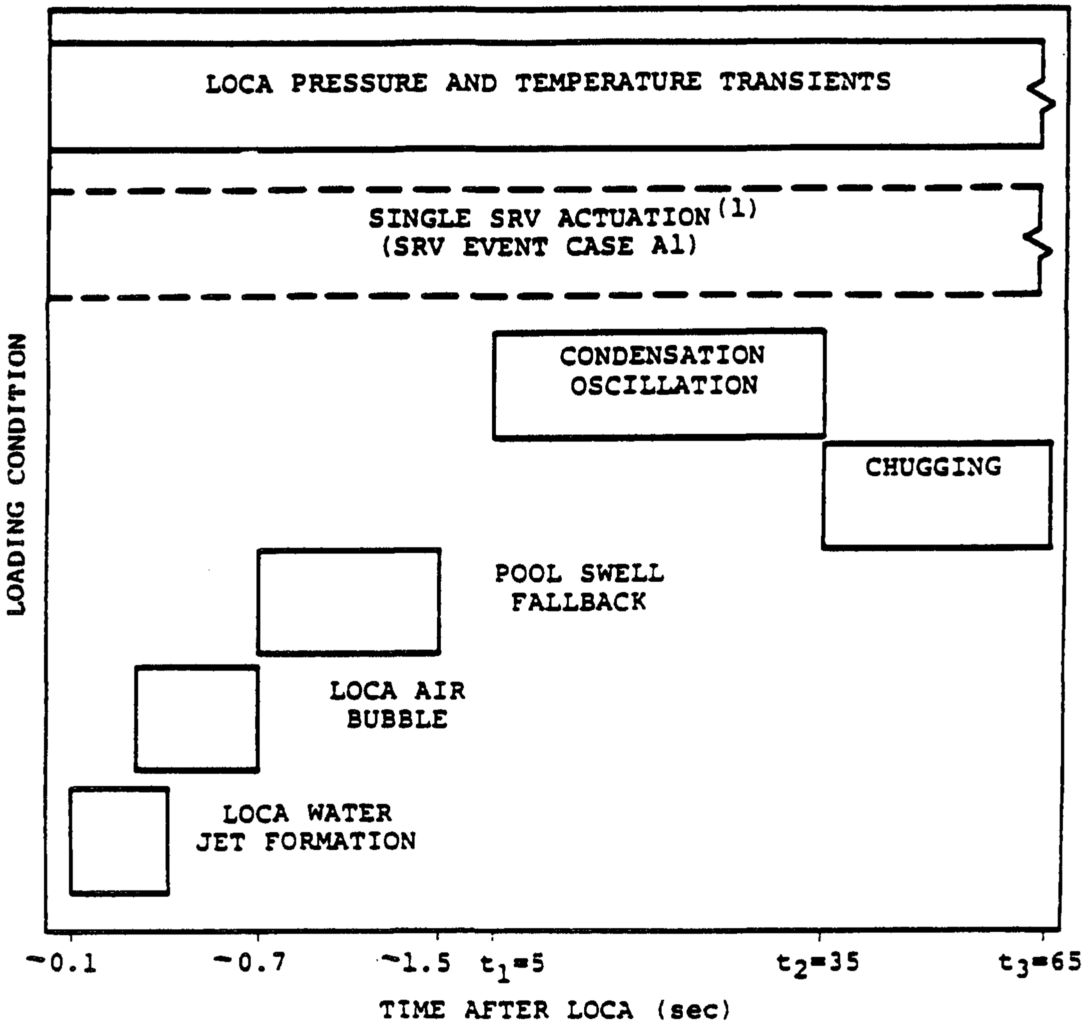


(1) THIS ACTUATION IS ASSUMED TO OCCUR COINCIDENT WITH THE POOL SWELL EVENT. ALTHOUGH SRV ACTUATION CAN OCCUR LATER IN THE DBA, THE RESULTING AIR LOADING ON THE TORUS SHELL IS NEGLIGIBLE, SINCE THE AIR AND WATER INITIALLY IN THE LINE WILL BE CLEARED AS THE DRYWELL-TO-WETWELL ΔP INCREASES DURING THE DBA TRANSIENT.

DRESDEN STATION
UNITS 2 & 3

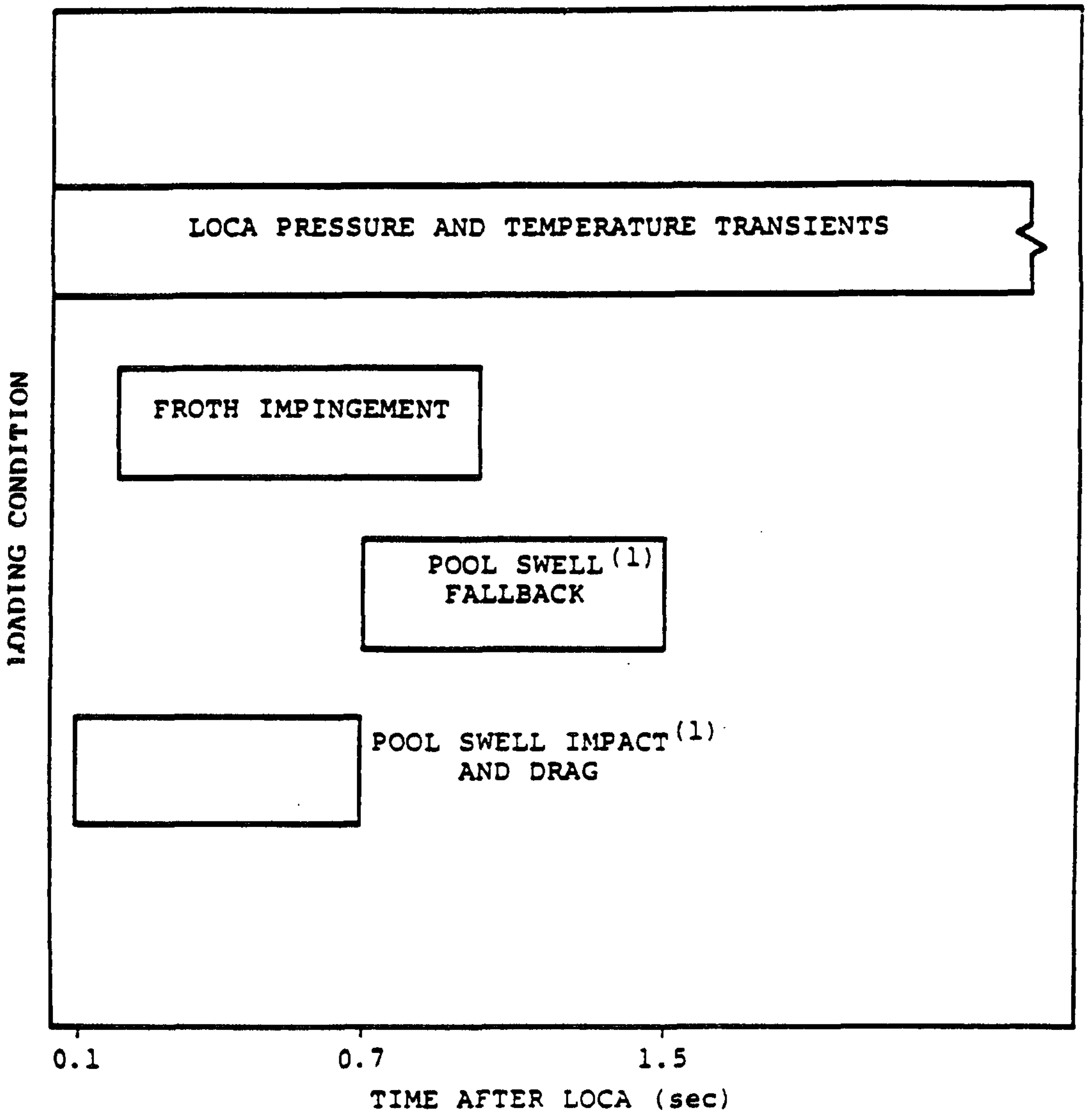
LOADING CONDITION COMBINATIONS FOR THE VENT HEADER, MAIN VENTS, DOWNCOMERS, AND TORUS SHELL DURING A DBA

FIGURE 6.2-22



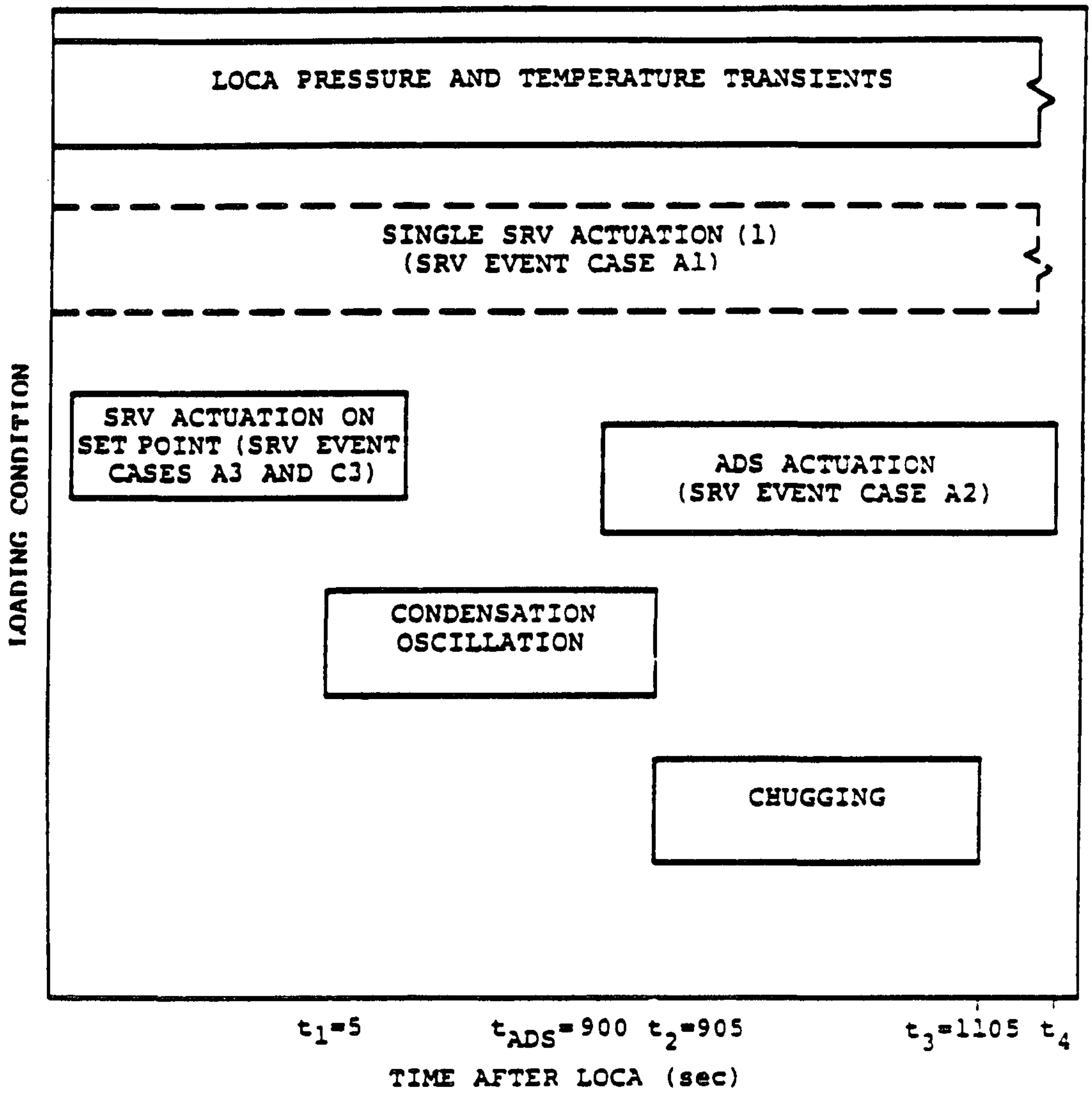
(1) THIS ACTUATION IS ASSUMED TO OCCUR COINCIDENT WITH THE POOL SWELL EVENT. ALTHOUGH SRV ACTUATION CAN OCCUR LATER IN THE DBA, THE RESULTING AIR LOADING ON THE TORUS SHELL IS NEGLIGIBLE, SINCE THE AIR AND WATER INITIALLY IN THE LINE WILL BE CLEARED AS THE DRYWELL-TO-WETWELL ΔP INCREASES DURING THE DBA TRANSIENT.

DRESDEN STATION UNITS 2 & 3
LOADING CONDITION COMBINATIONS FOR SUBMERGED STRUCTURES DURING A DBA
FIGURE 6.2-23



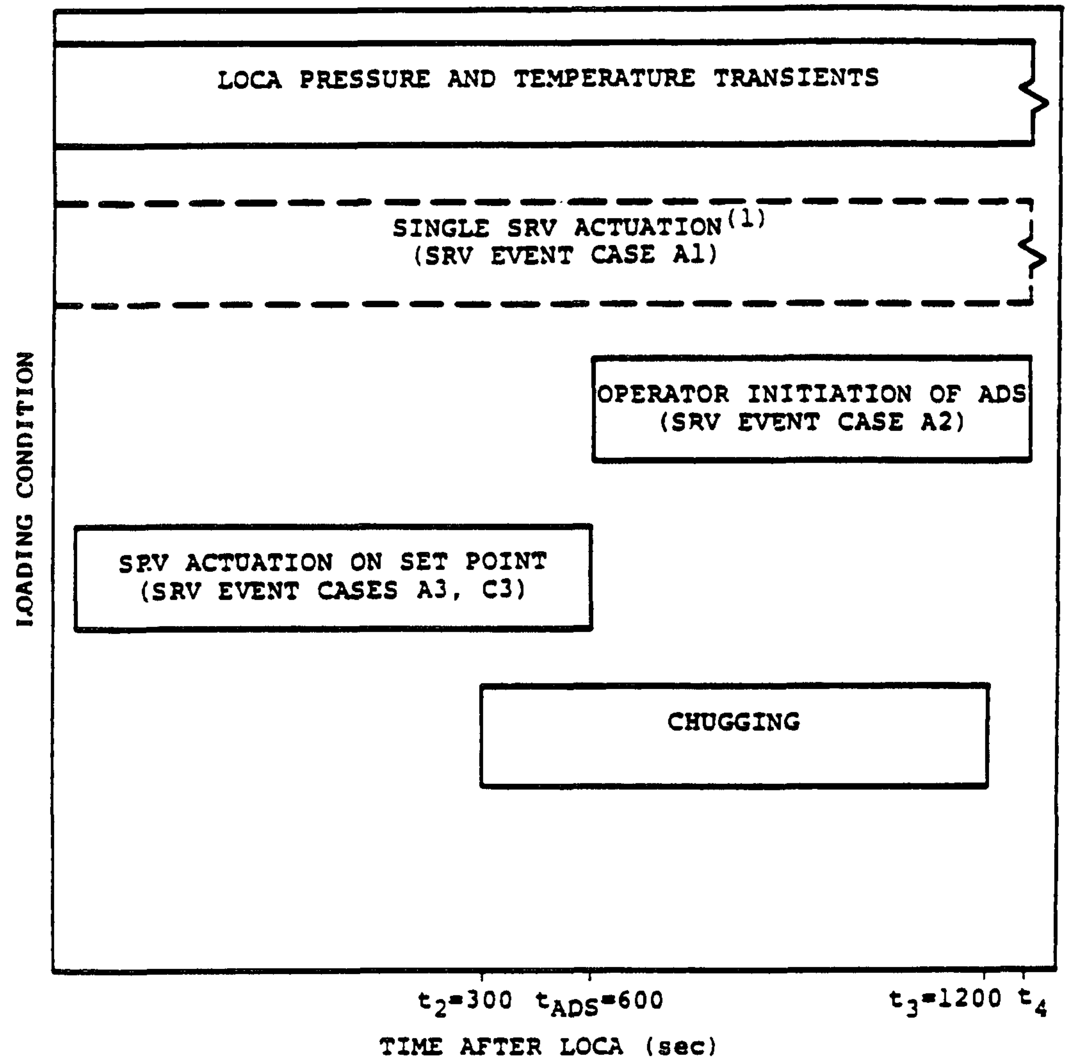
(1) STRUCTURES ARE BELOW MAXIMUM POOL SWELL HEIGHT.

DRESDEN STATION UNITS 2 & 3
LOADING CONDITION FOR SMALL STRUCTURES ABOVE SUPPRESSION POOL DURING A DBA
FIGURE 6.2-24



(1) LOADING NOT COMBINED WITH OTHER SRV CASES.

DRESDEN STATION UNITS 2 & 3
LOADING CONDITION COMBINATIONS FOR THE VENT HEADER, MAIN VENTS, DOWNCOMERS, TORUS SHELL, AND SUBMERGED STRUCTURES DURING AN IBA
FIGURE 6.2-25

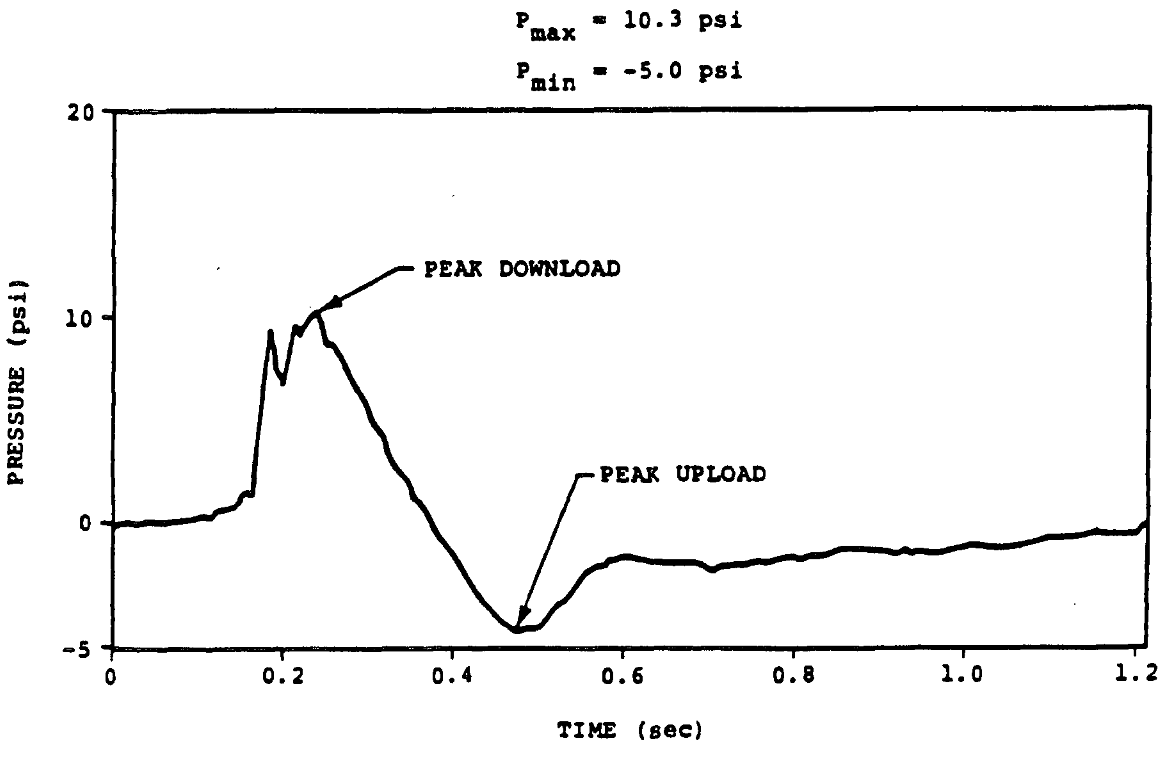


(1) LOADING NOT COMBINED WITH OTHER SRV CASES.

DRESDEN STATION
UNITS 2 & 3

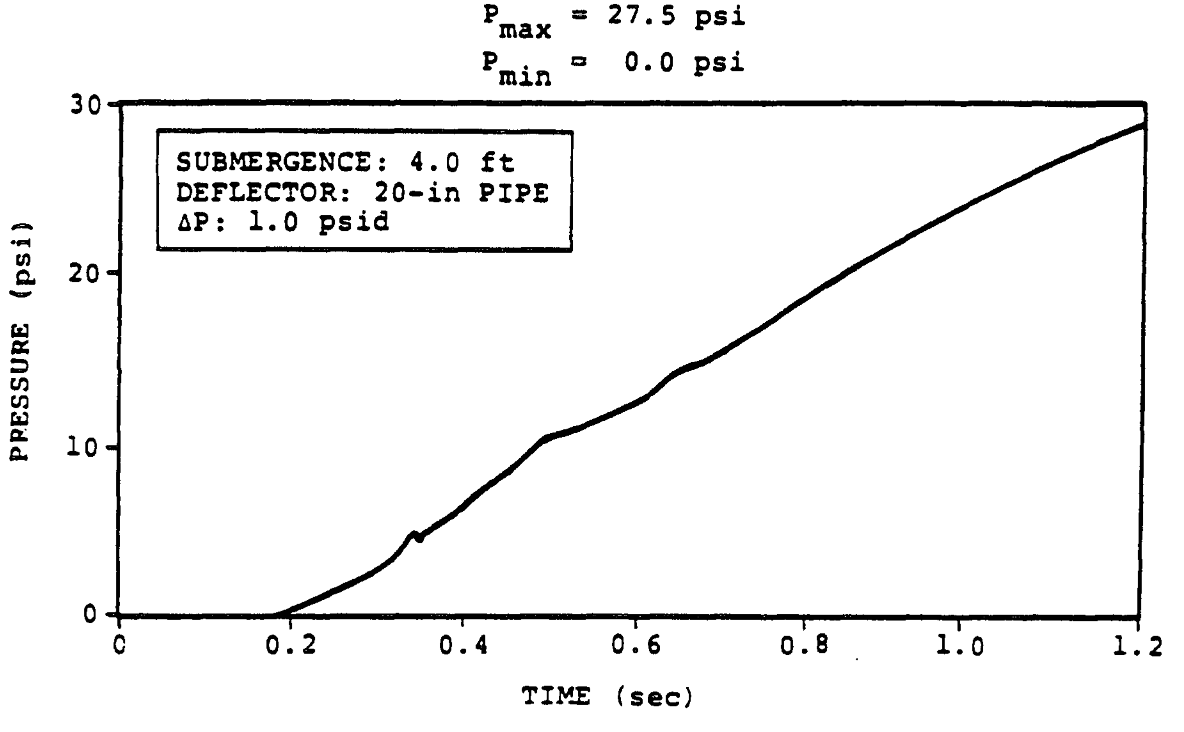
LOADING CONDITION COMBINATIONS FOR THE VENT HEADER, MAIN VENTS, DOWNCOMERS, TORUS SHELL, AND SUBMERGED STRUCTURES DURING A SBA

FIGURE 6.2-26



1. PRESSURES SHOWN DO NOT INCLUDE DBA INTERNAL PRESSURE.

DRESDEN STATION UNITS 2 & 3
POOL SWELL TORUS SHELL PRESSURE TRANSIENT AT SUPPRESSION CHAMBER MITER JOINT - BOTTOM DEAD CENTER (OPERATING DIFFERENTIAL PRESSURE)
FIGURE 6.2-27

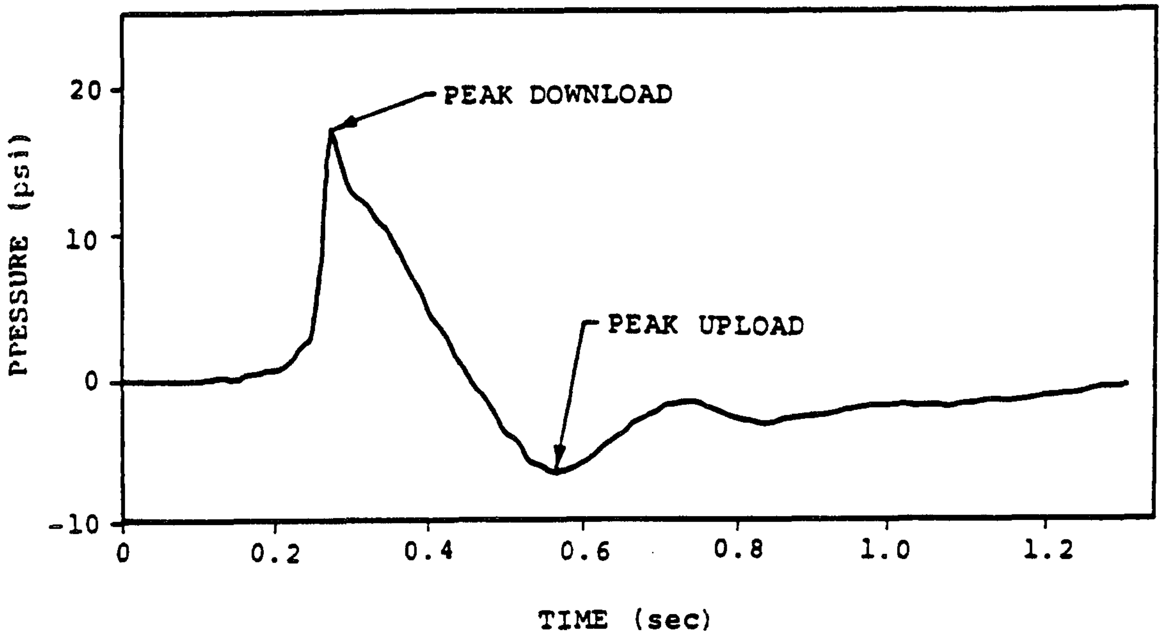


DRESDEN STATION
UNITS 2 & 3

POOL SWELL TORUS SHELL PRESSURE TRANSIENT FOR SUPPRESSION CHAMBER AIRSPACE (OPERATING DIFFERENTIAL PRESSURE)

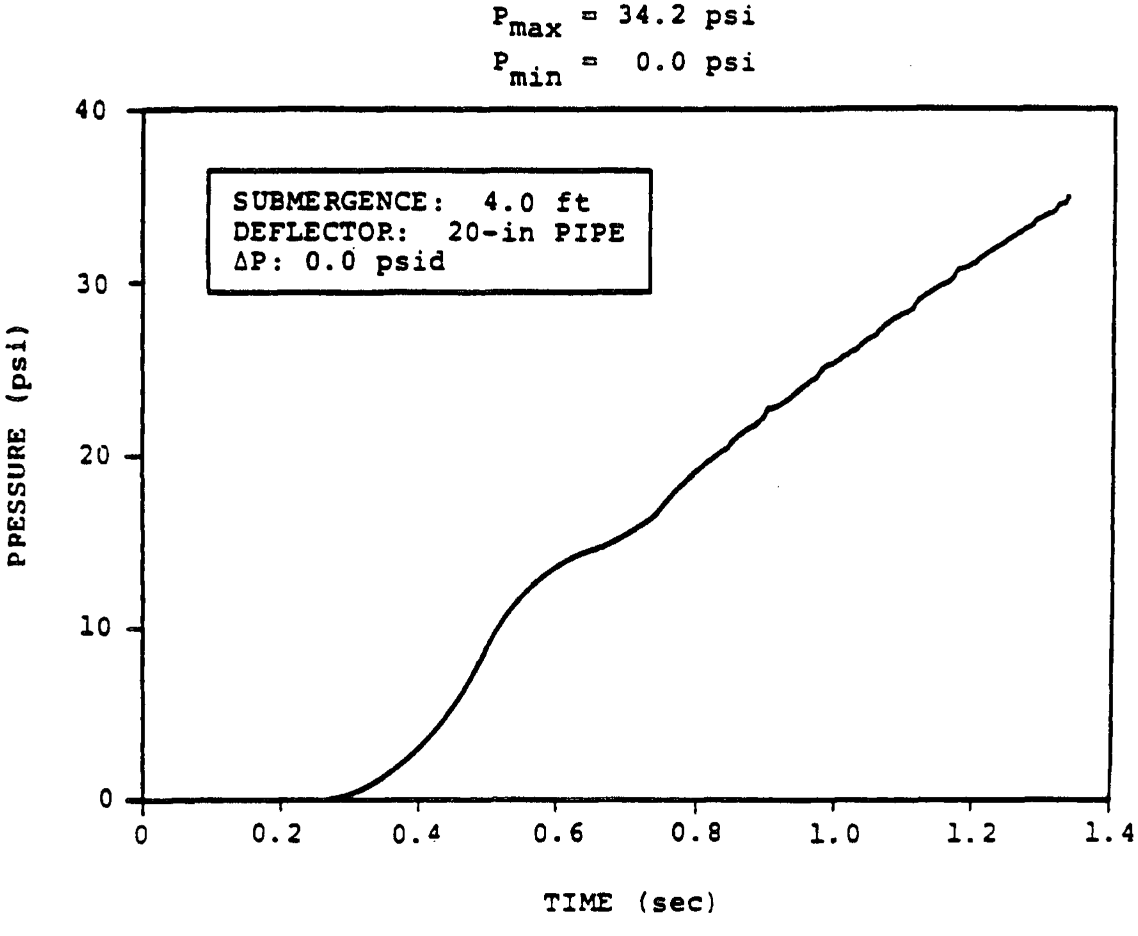
FIGURE 6.2-28

P_{max} = 17.2 psi
P_{min} = -6.2 psi



1. PRESSURES SHOWN DO NOT INCLUDE DBA INTERNAL PRESSURE.

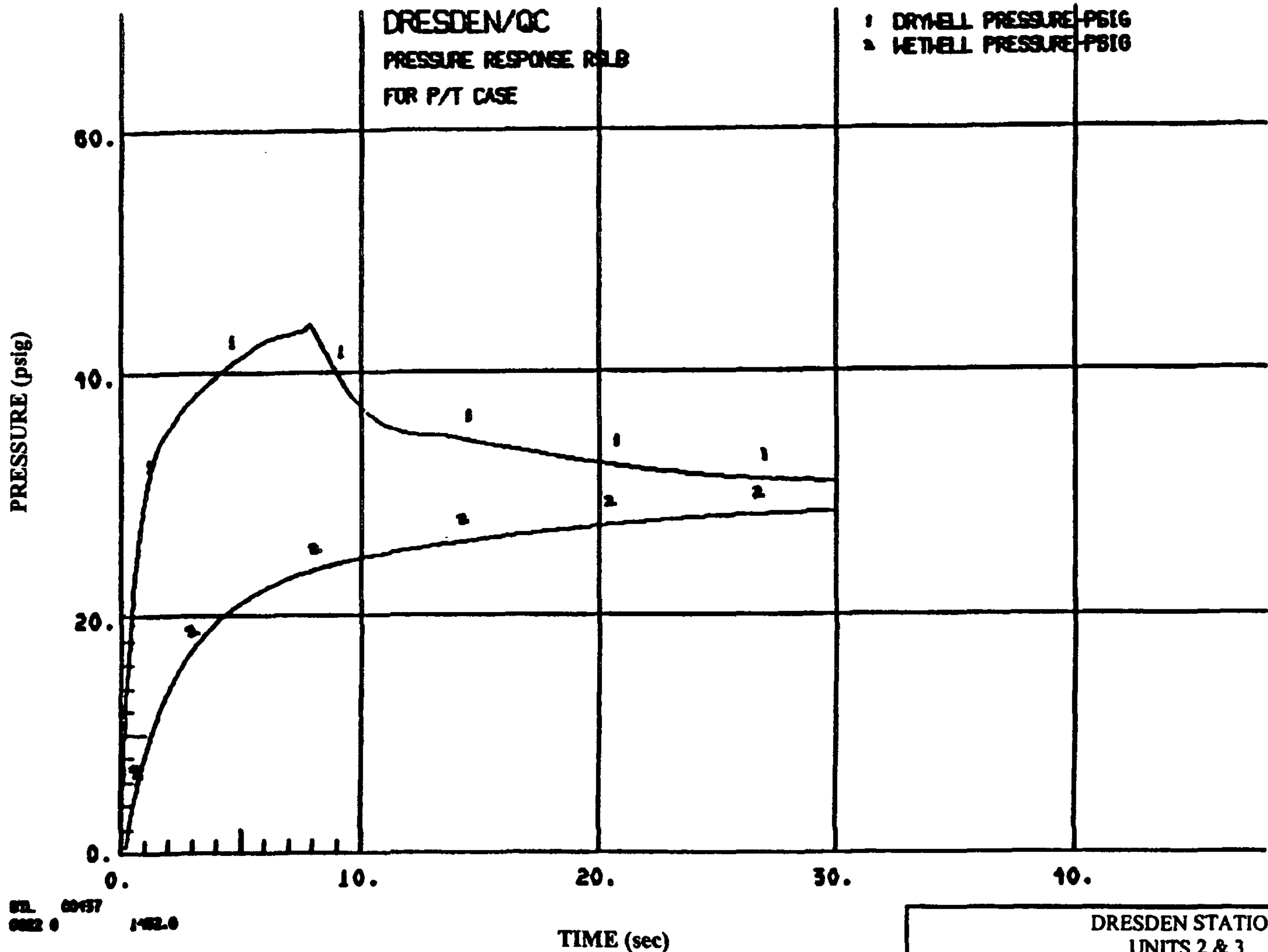
DRESDEN STATION UNITS 2 & 3
POOL SWELL TORUS SHELL PRESSURE TRANSIENT AT SUPPRESSION CHAMBER MITER JOINT - BOTTOM DEAD CENTER (ZERO DIFFERENTIAL PRESSURE)
FIGURE 6.2-29



DRESDEN STATION
UNITS 2 & 3

POOL SWELL TORUS SHELL PRESSURE TRANSIENT FOR SUPPRESSION CHAMBER AIRSPACE (ZERO DIFFERENTIAL PRESSURE)

FIGURE 6.2-30

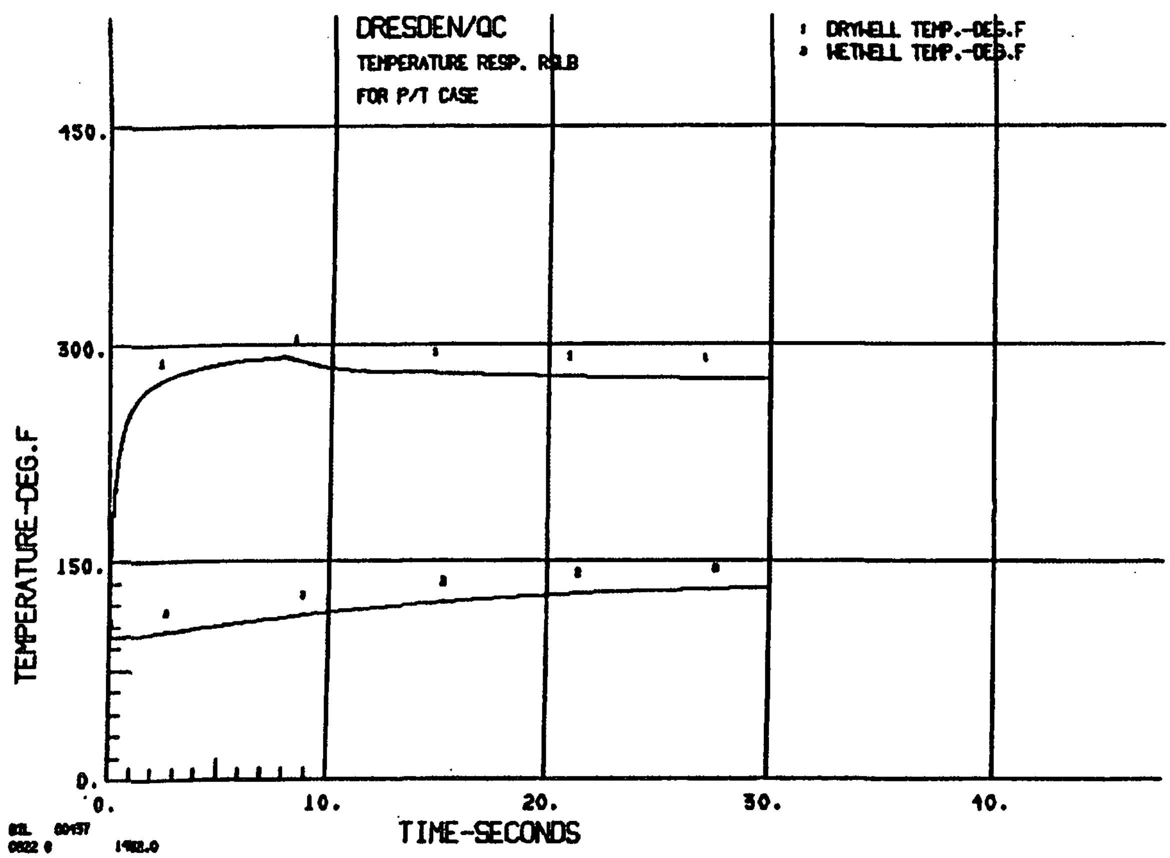


DRESDEN STATION
UNITS 2 & 3

SHORT-TERM CONTAINMENT PRESSURE RESPONSE TO DBA-LOCA FOR DRESDEN AT 2957 MWT

FIGURE 6.2-31

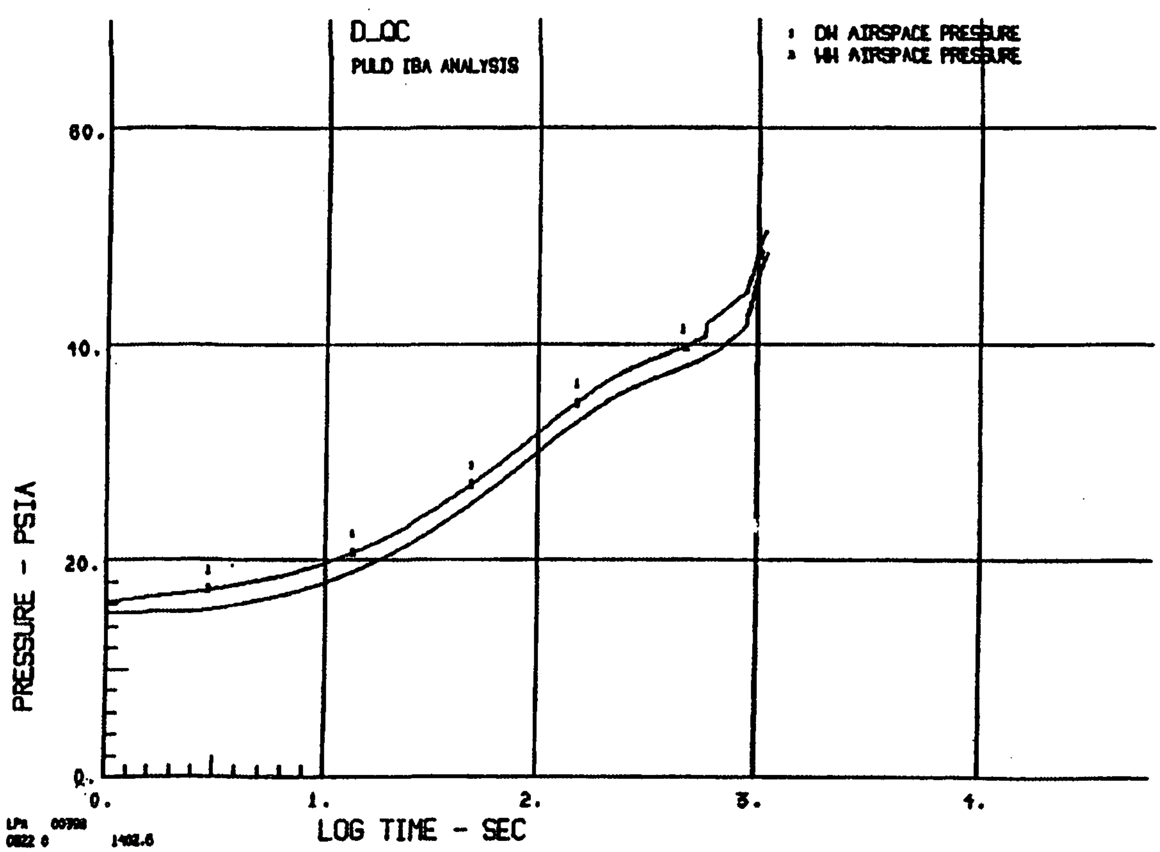
REVISION 5, JANUARY 2003



DRESDEN STATION
UNITS 2 & 3

SHORT-TERM CONTAINMENT TEMPERATURE
RESPONSE TO DBA-LOCA FOR DRESDEN
(AT 2957 MWt)

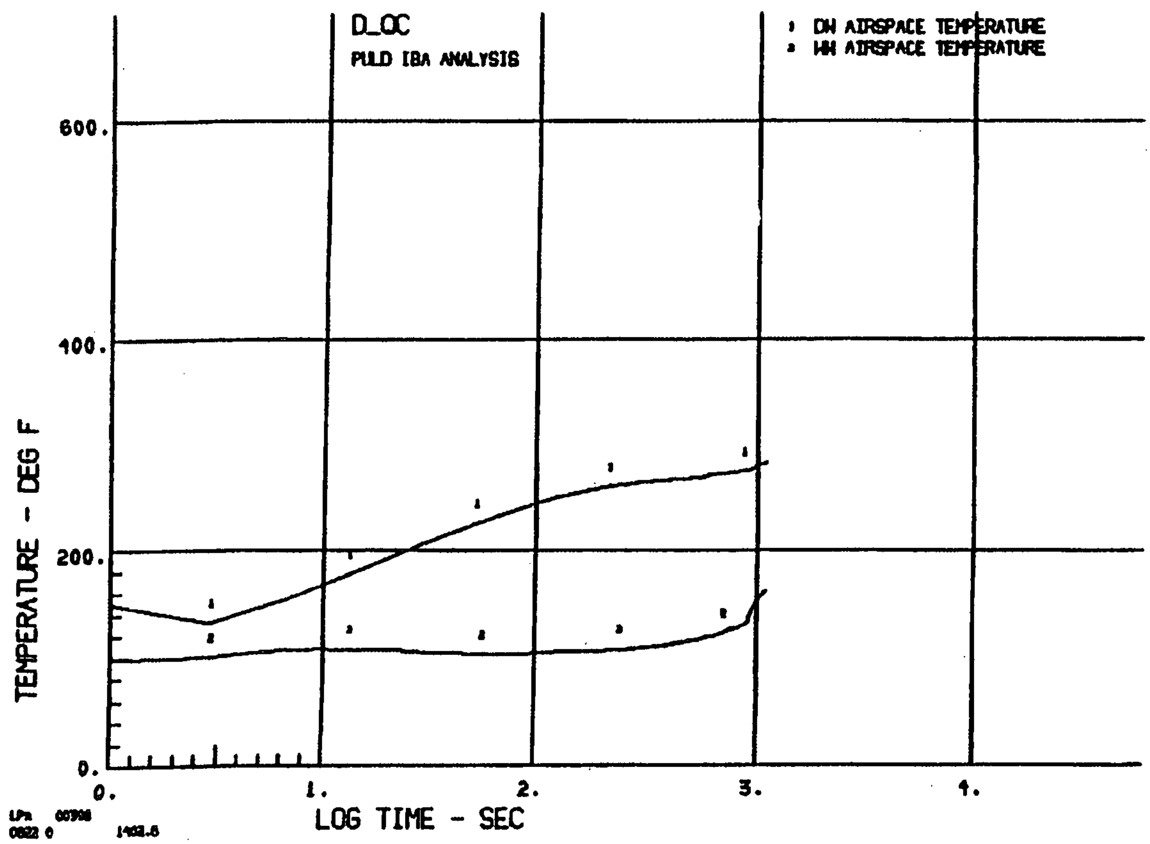
FIGURE 6.2-33



DRESDEN STATION
UNITS 2 & 3

CONTAINMENT PRESSURE RESPONSE TO IBA
FOR DRESDEN (AT 2957 MWt)

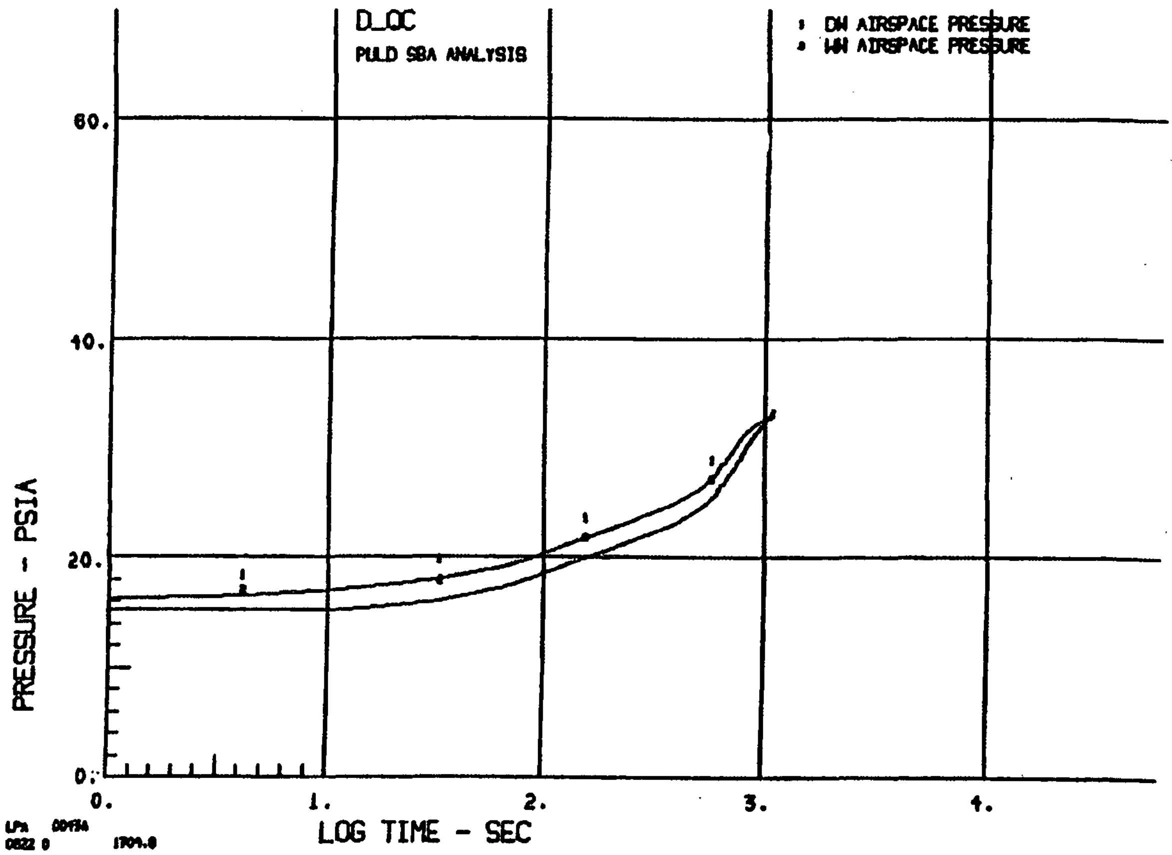
FIGURE 6.2-35



DRESDEN STATION
UNITS 2 & 3

CONTAINMENT TEMPERATURE RESPONSE TO IBA FOR DRESDEN (AT 2957 MWt)

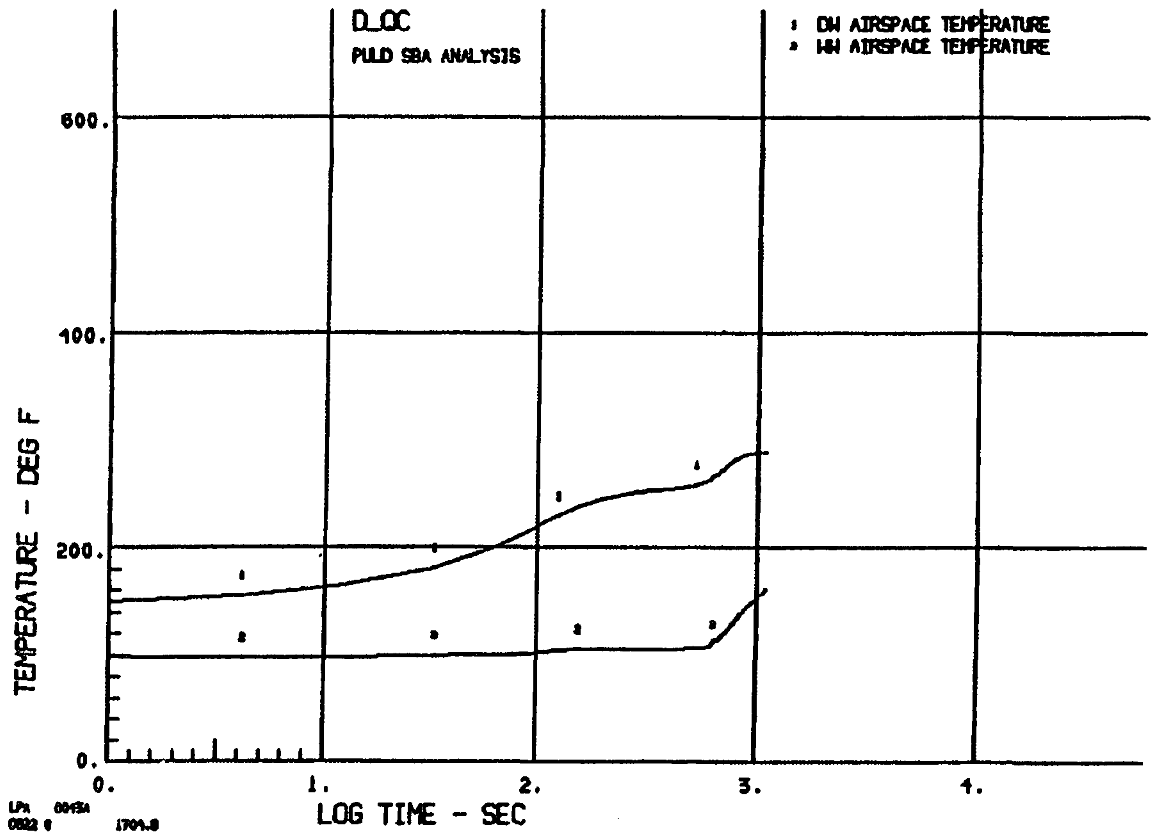
FIGURE 6.2-36



DRESDEN STATION
UNITS 2 & 3

CONTAINMENT PRESSURE RESPONSE TO SBA
FOR DRESDEN (AT 2957 MWt)

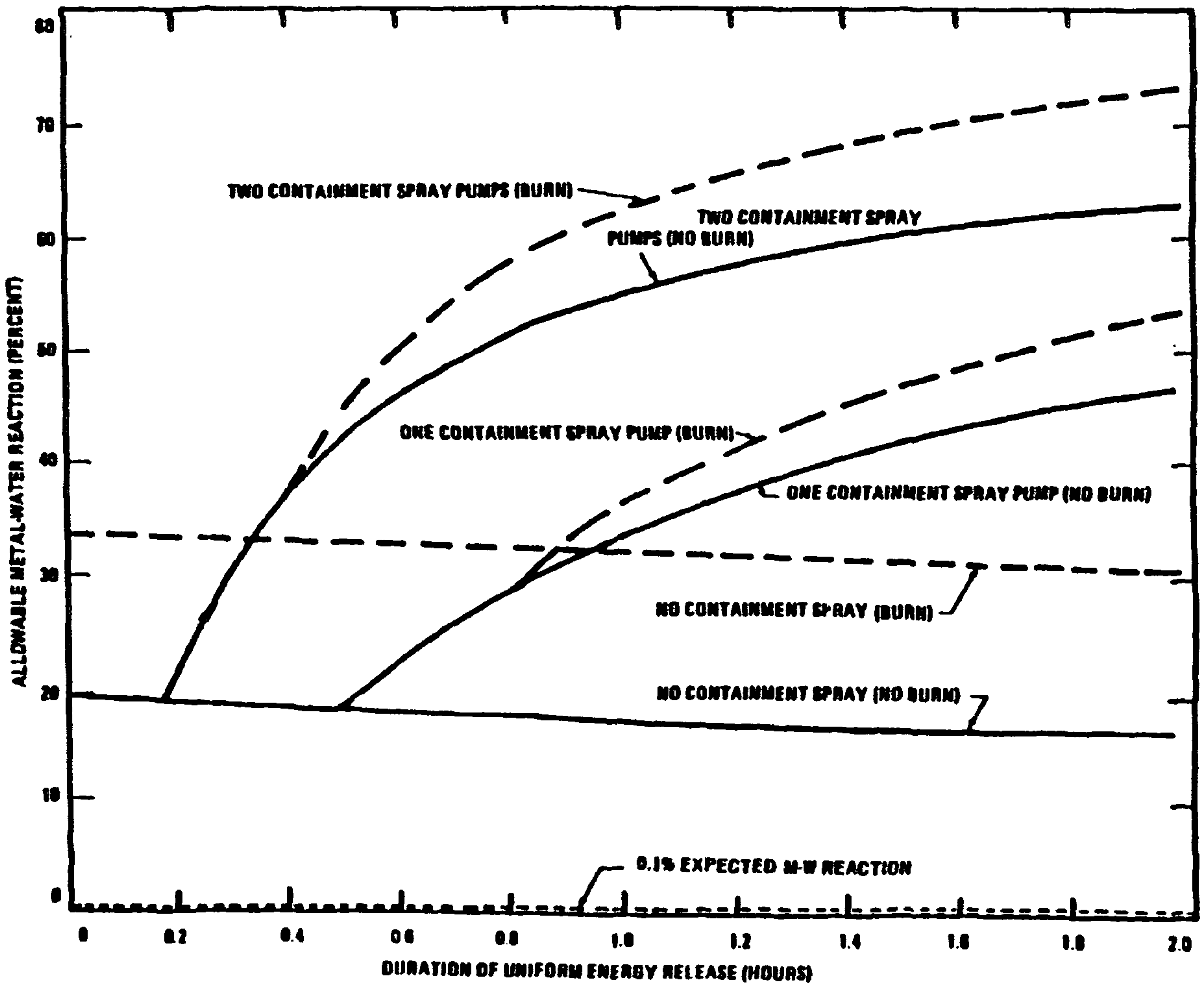
FIGURE 6.2-37



DRESDEN STATION
UNITS 2 & 3

CONTAINMENT TEMPERATURE RESPONSE TO SBA FOR DRESDEN (AT 2957 MWt)

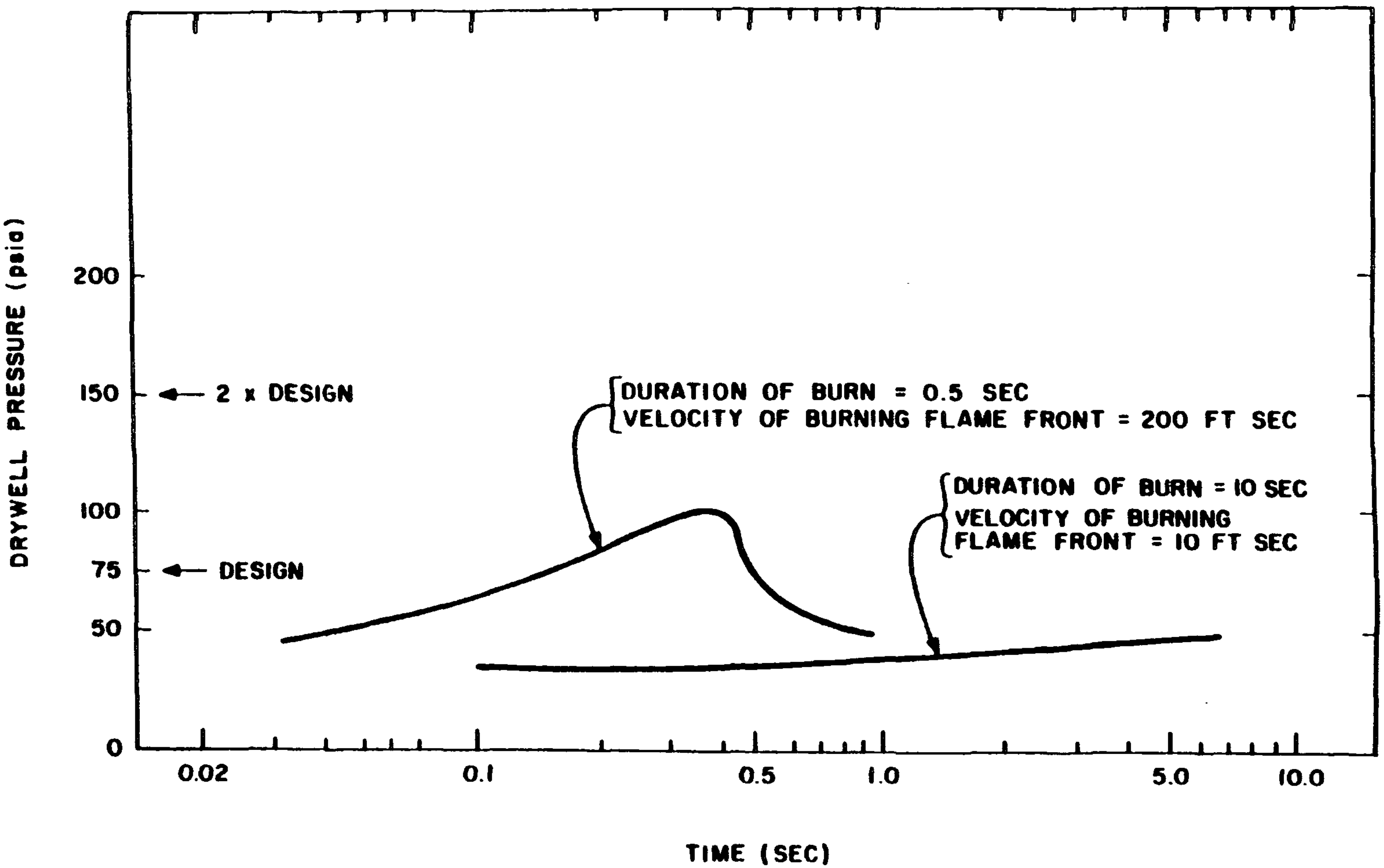
FIGURE 6.2-38



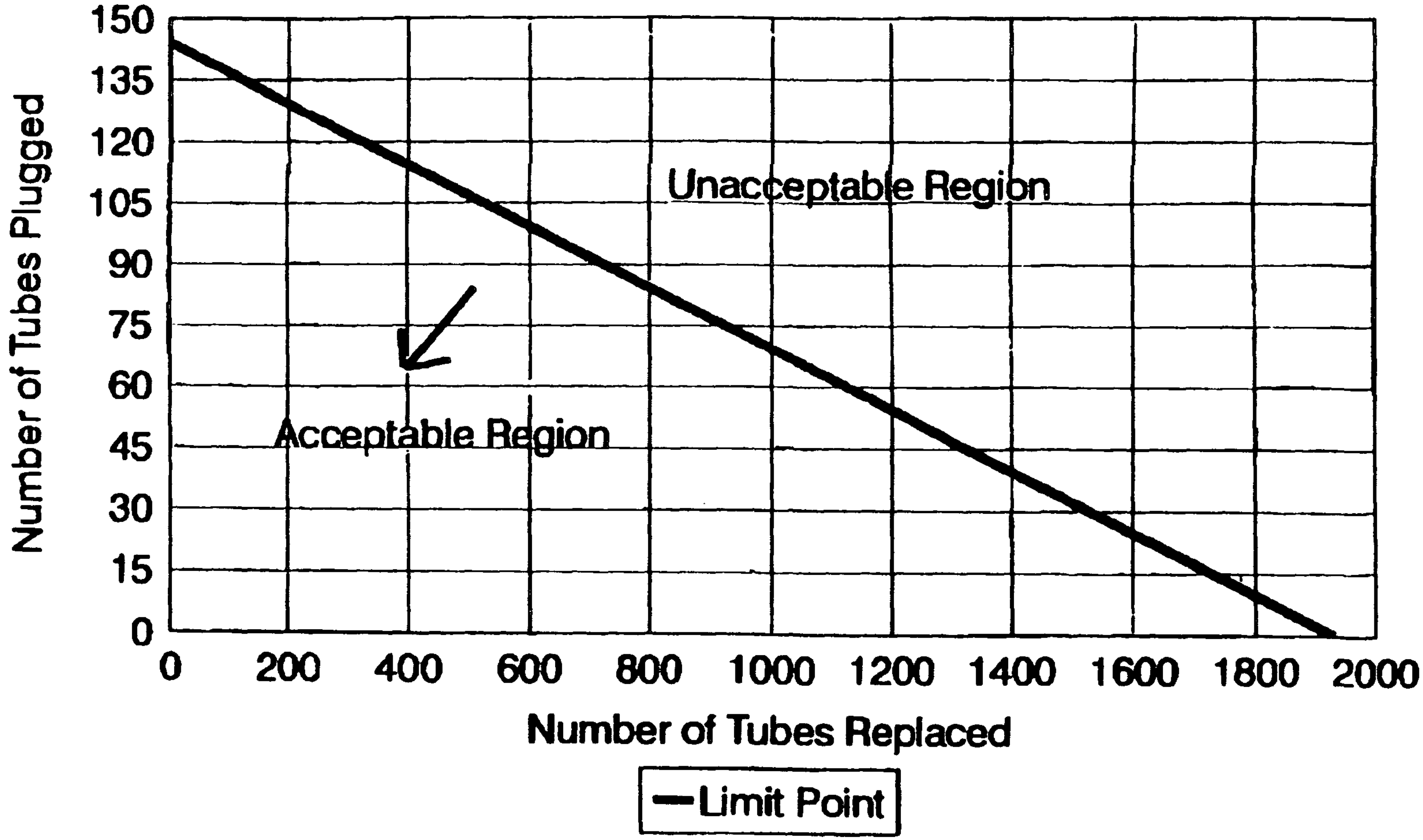
DRESDEN STATION
UNITS 2 & 3

CONTAINMENT CAPABILITY

FIGURE 6.2-40

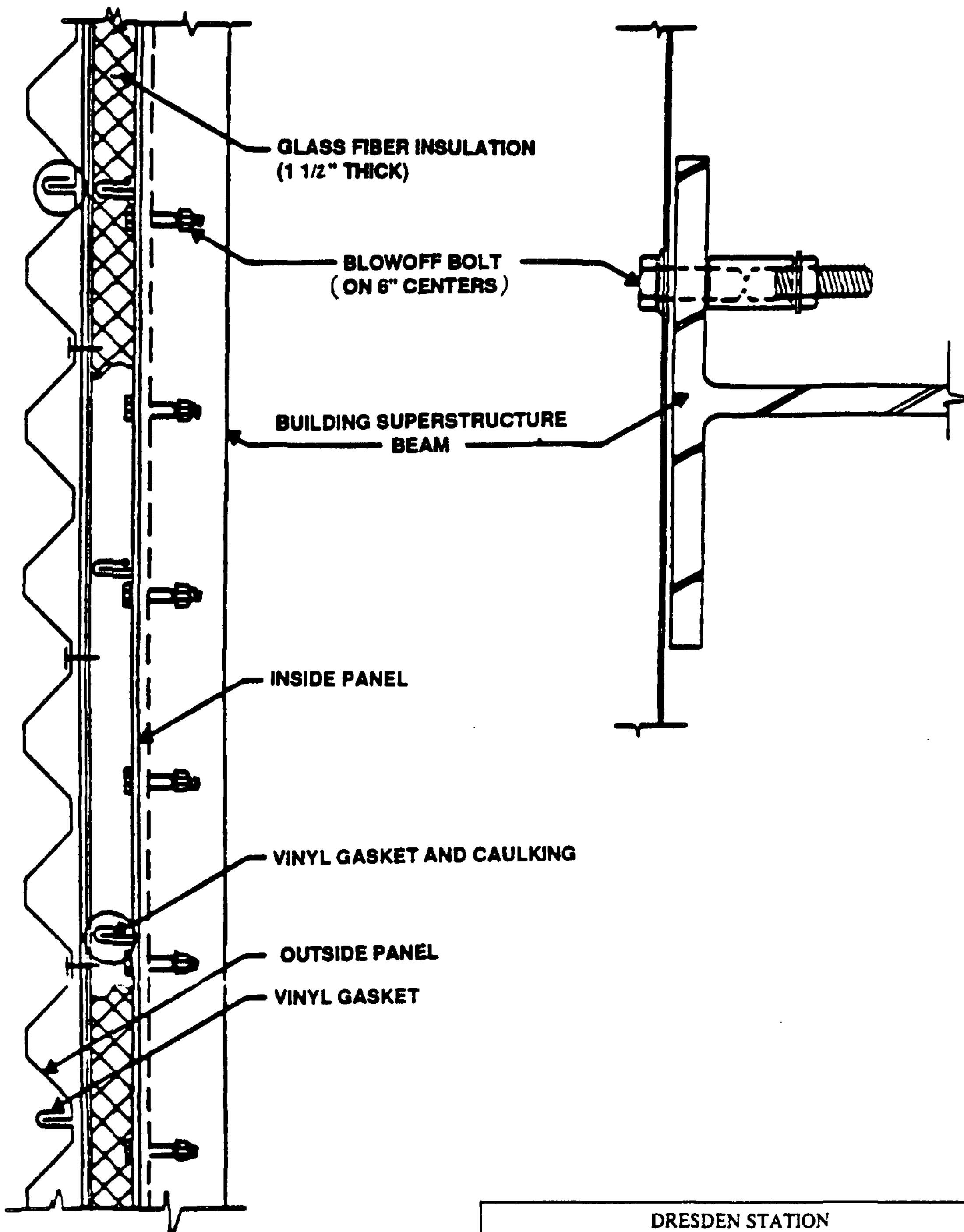


DRESDEN STATION UNITS 2 & 3
DRYWELL PRESSURE VS. TIME - RAPID BURNING IN DRYWELL
FIGURE 6.2-41

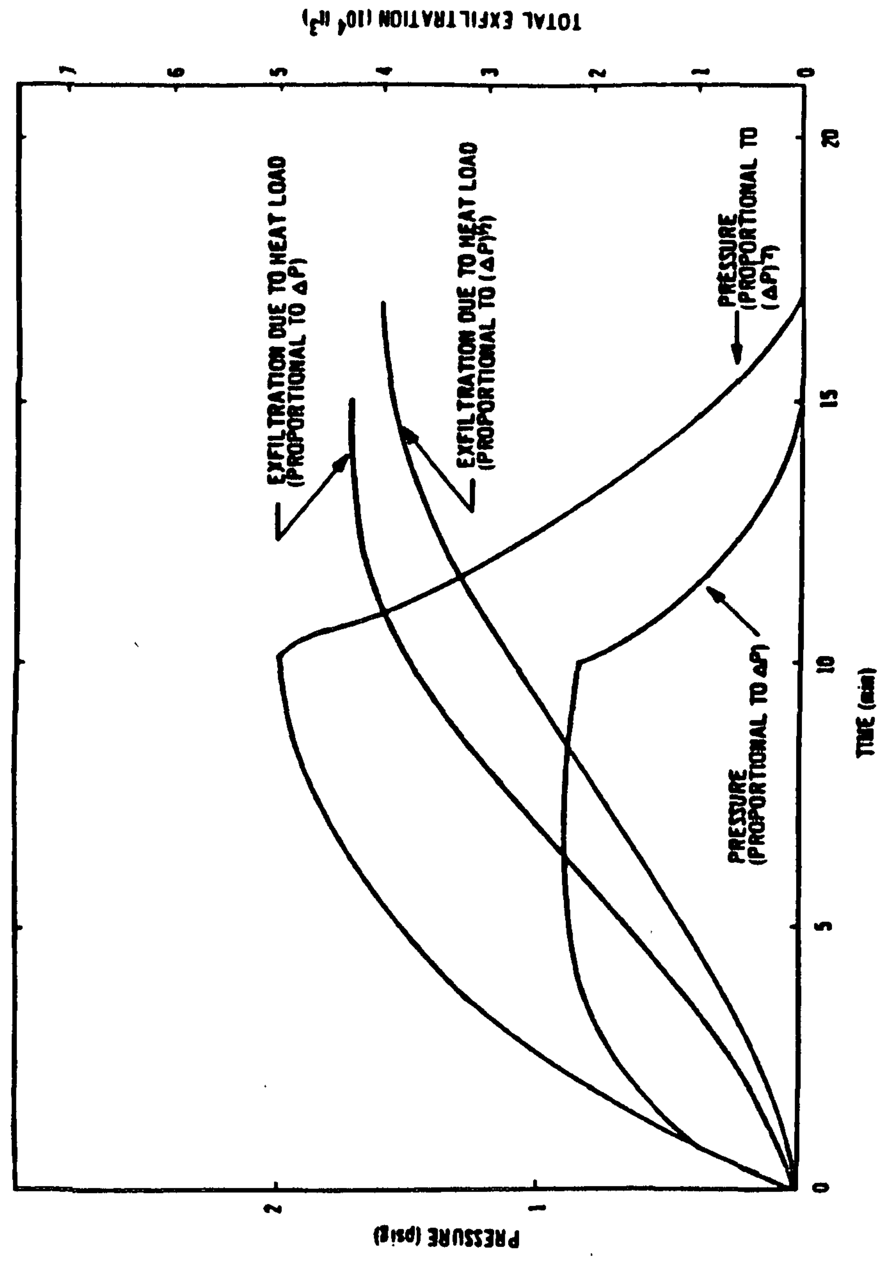


based on 6% design plugging allowance

DRESDEN STATION UNITS 2 & 3
LPCI HEAT EXCHANGER TUBE REPLACEMENT WITH AL 6XN VERSUS PLUGGING
FIGURE 6.2-42



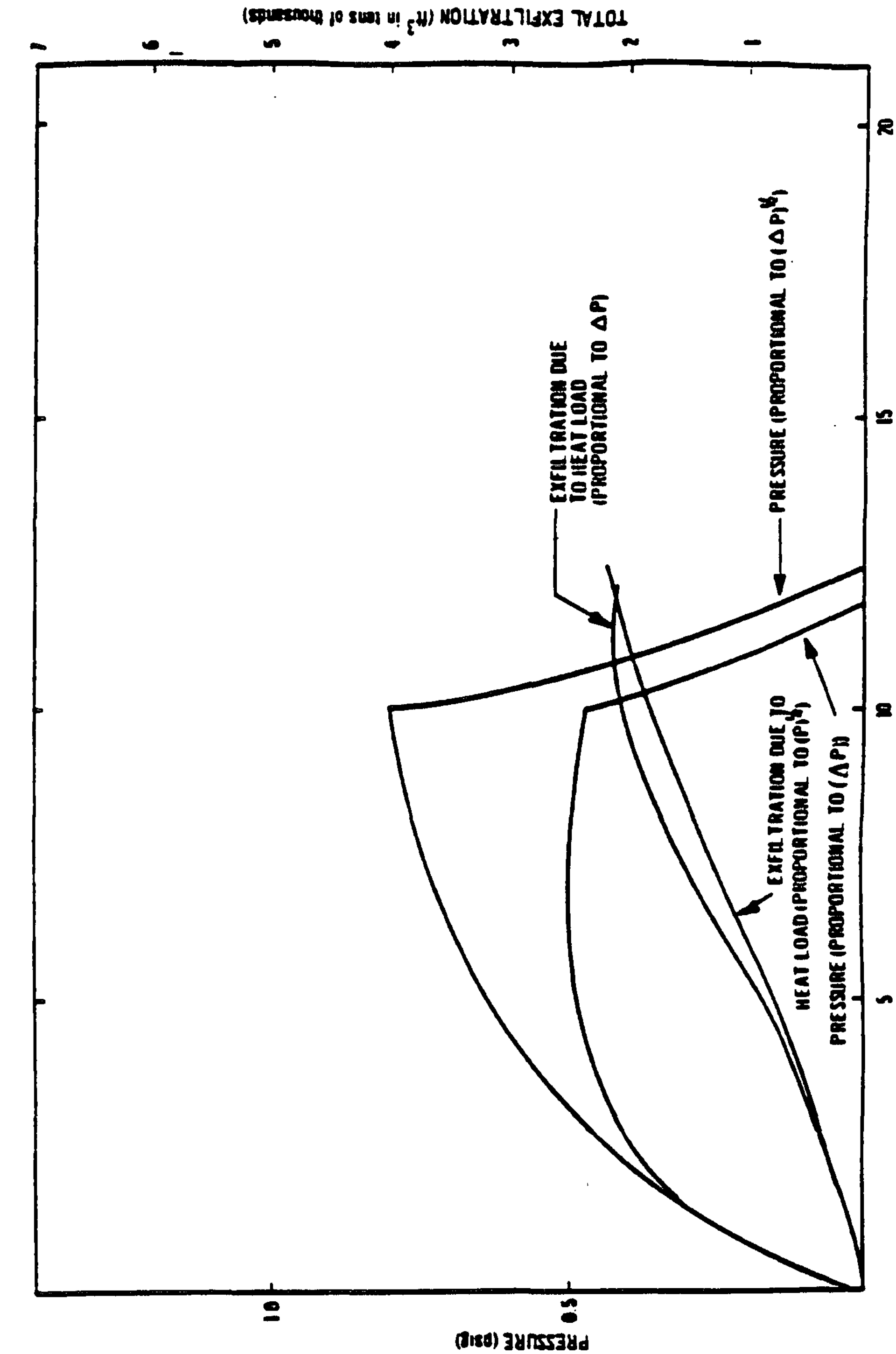
DRESDEN STATION UNITS 2 & 3
REACTOR BUILDING SUPERSTRUCTURE BLOW-OFF DETAILS
FIGURE 6.2-43



DRESDEN STATION
UNITS 2 & 3

SECONDARY CONTAINMENT PRESSURE AND EXFILTRATION AFTER A LOCA WITH FAN STARTED TEN MINUTES AFTER ACCIDENT

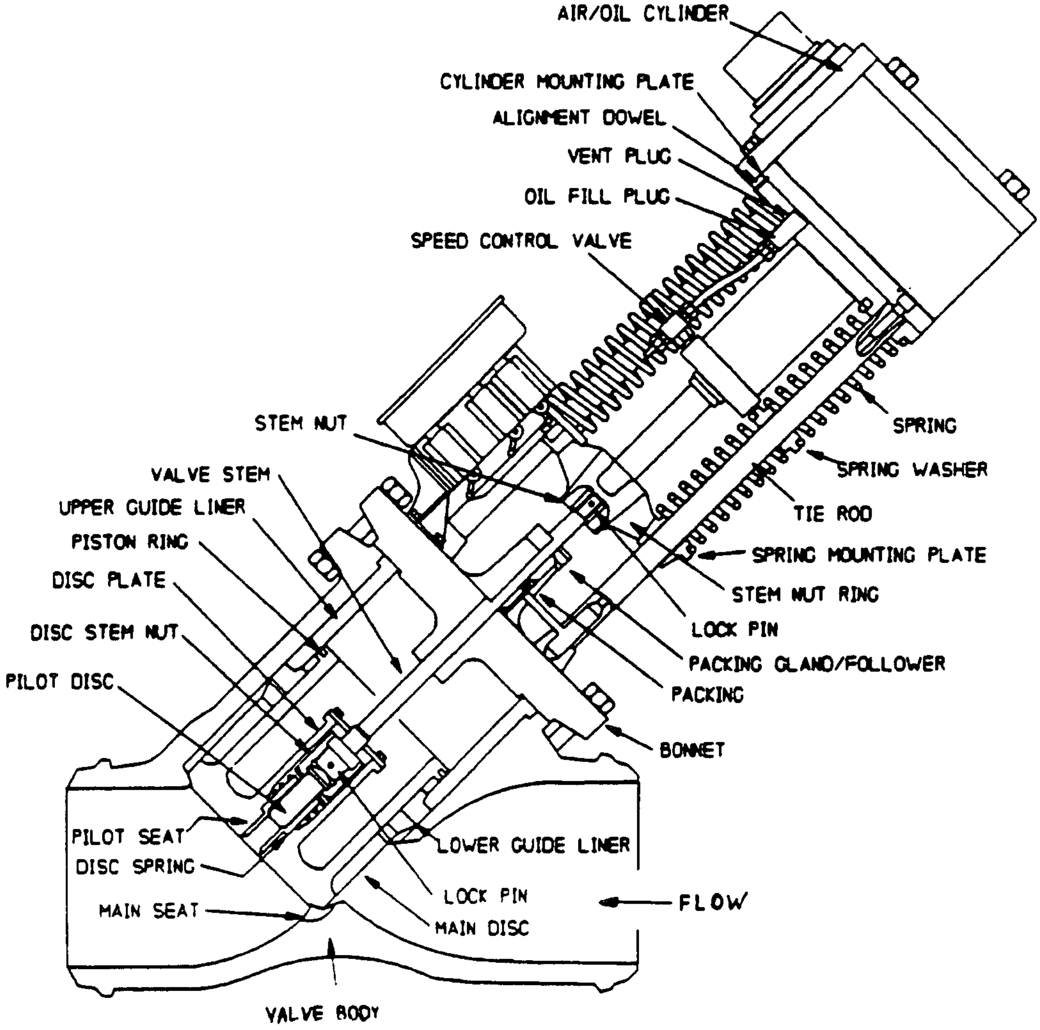
FIGURE 6.2-44



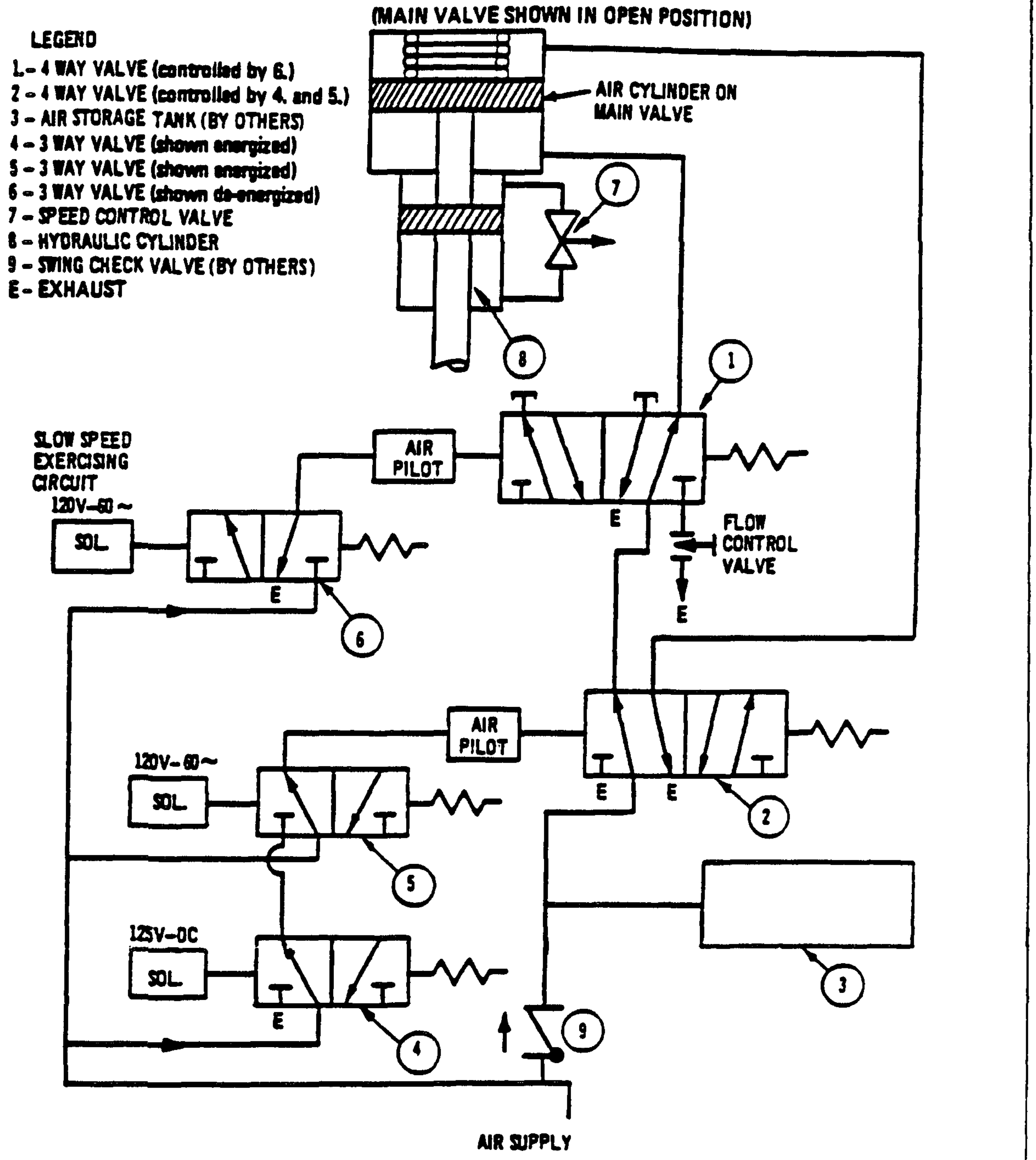
DRESDEN STATION
UNITS 2 & 3

SECONDARY CONTAINMENT PRESSURE & EXFILTRATION AFTER REFUELING ACCIDENT WITH FAN STARTED TEN MINUTES AFTER REFUELING ACCIDENT

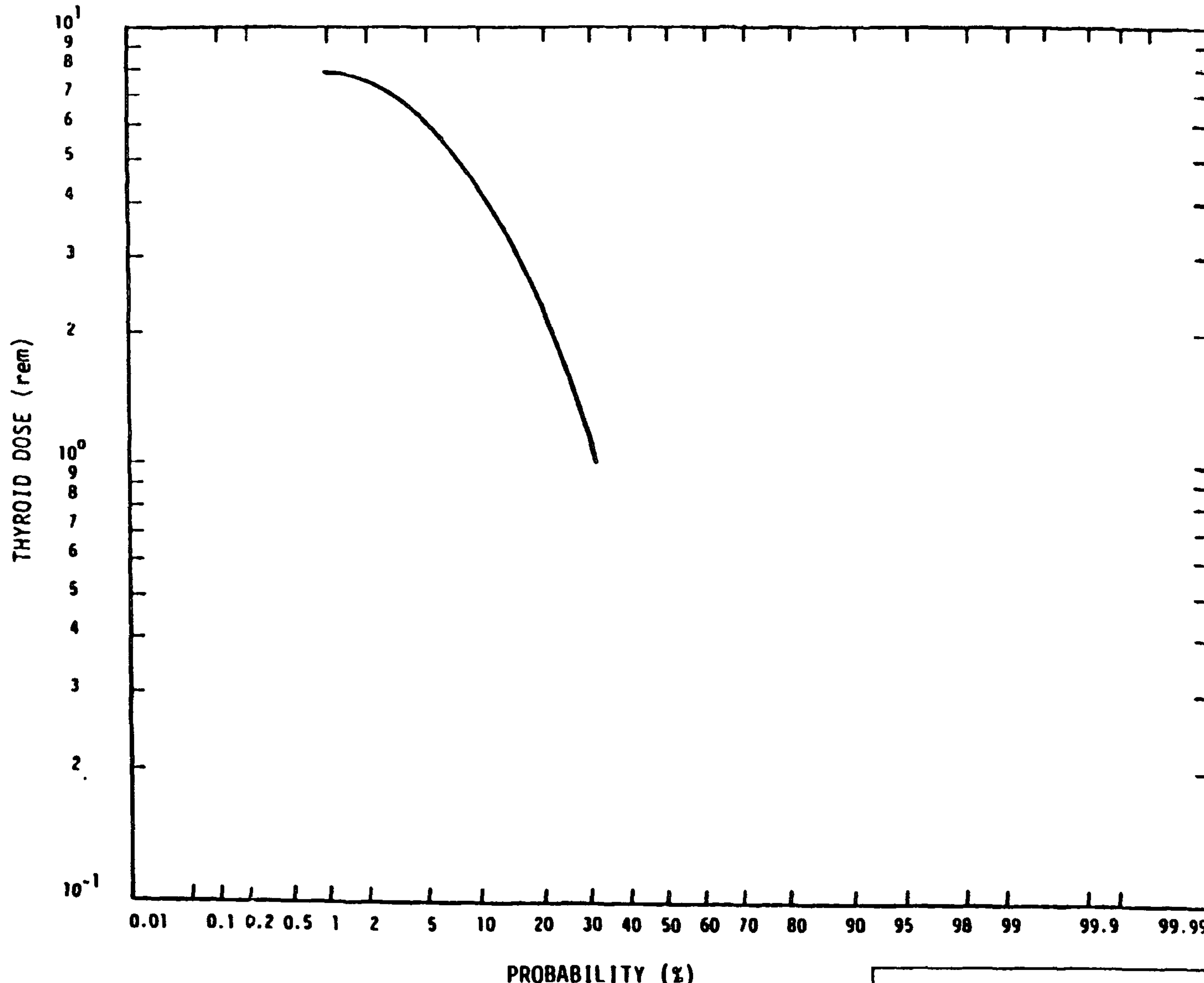
FIGURE 6.2-45



DRESDEN STATION UNITS 2 & 3
MAIN STEAM ISOLATION VALVE SECTION
FIGURE 6.2-46



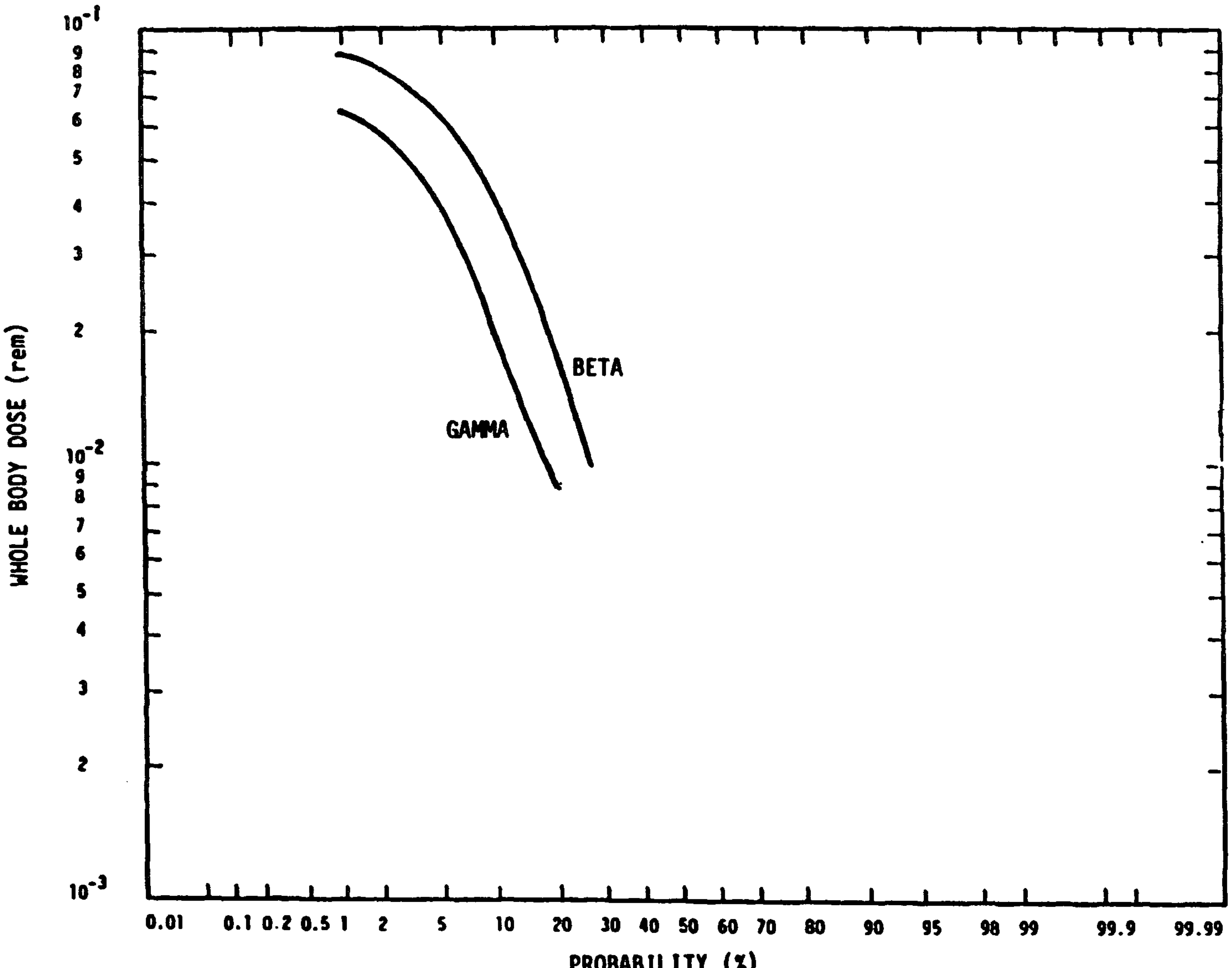
DRESDEN STATION UNITS 2 & 3
MAIN STEAM ISOLATION VALVE CONTROL DIAGRAM
FIGURE 6.2-47



DRESDEN STATION
UNITS 2 & 3

PROBABILITY VERSUS THYROID DOSE

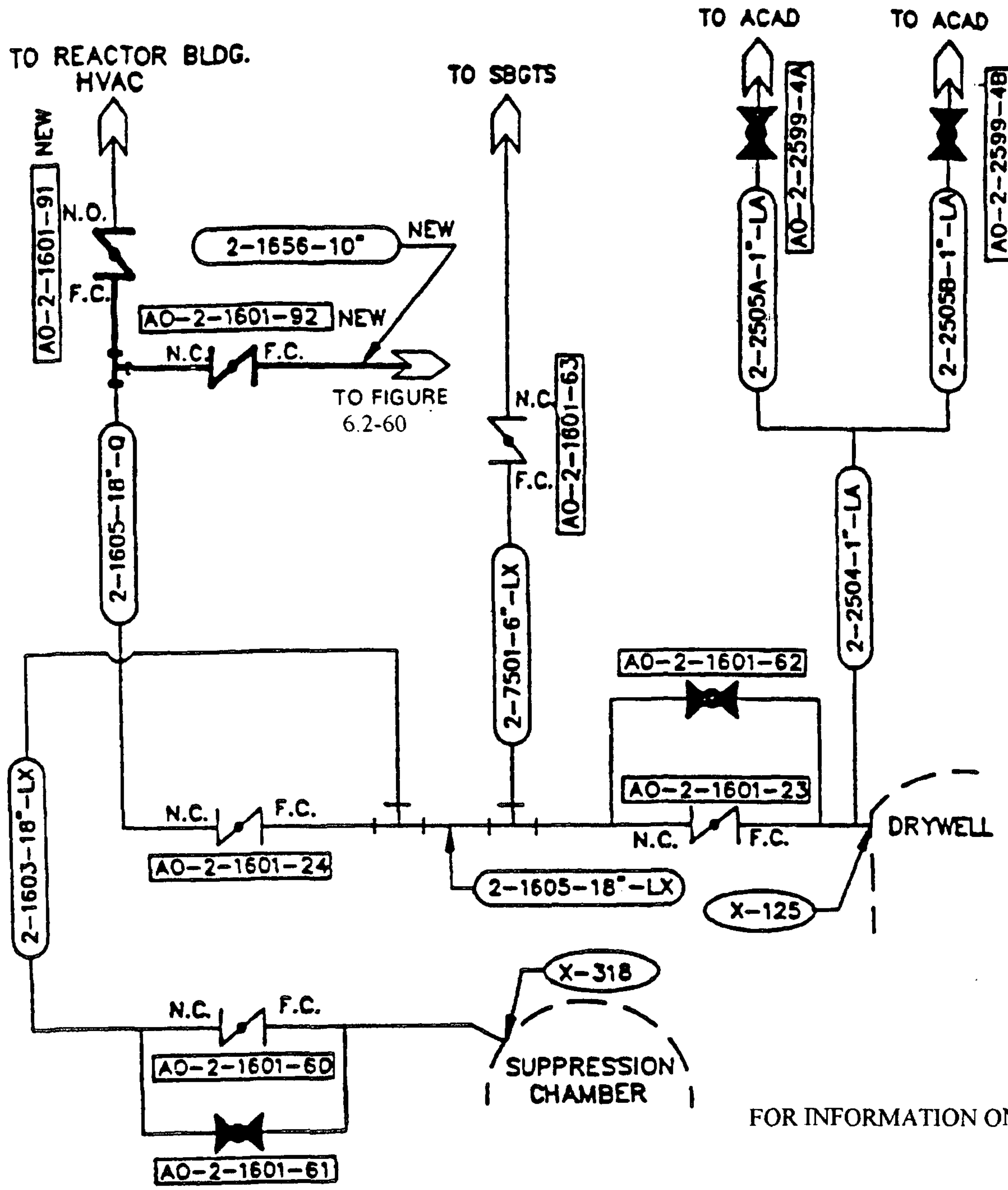
FIGURE 6.2-57



DRESDEN STATION
UNITS 2 & 3

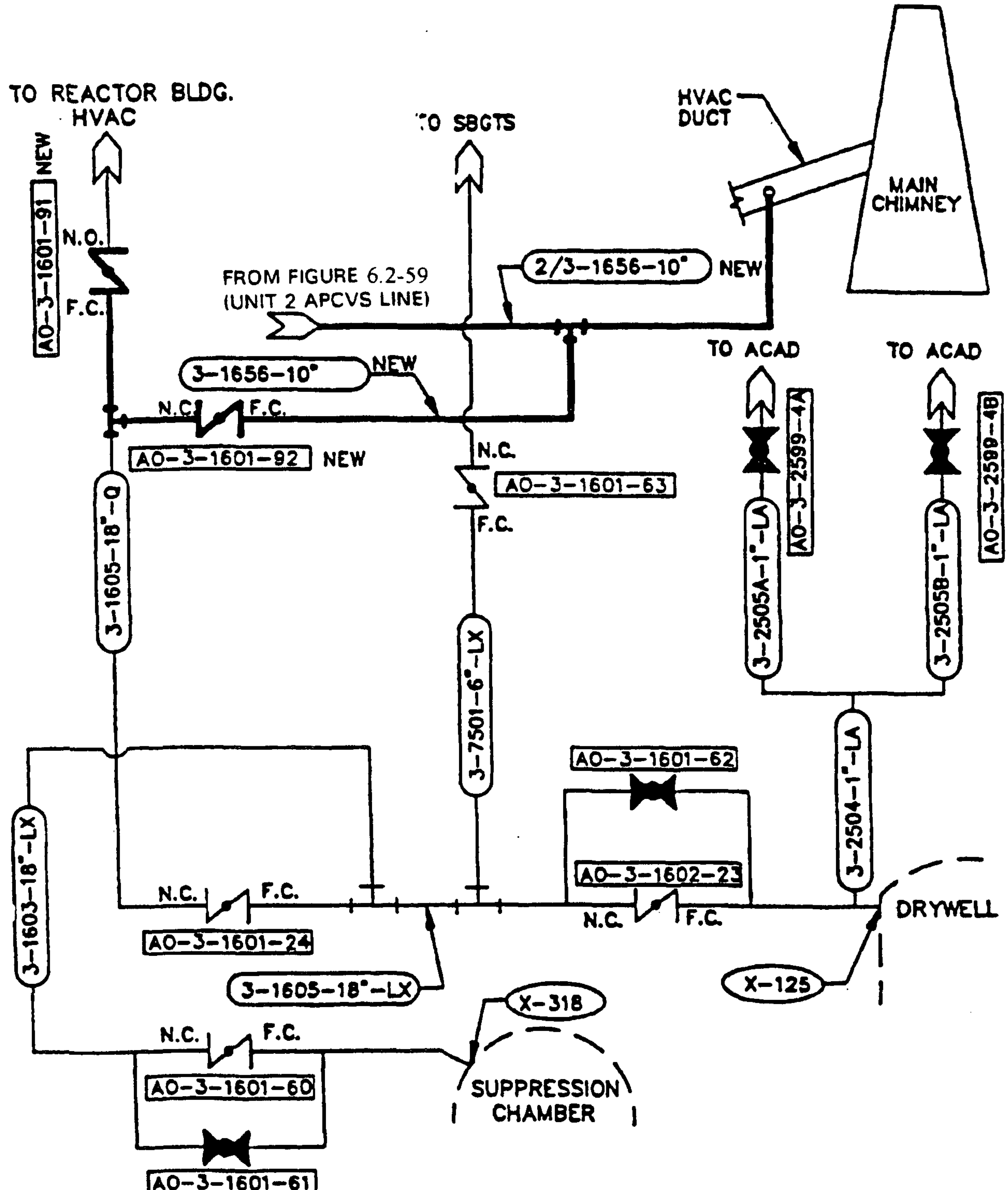
PROBABILITY VERSUS WHOLE BODY DOSE

FIGURE 6.2-58



FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
AUGUMENTED PRIMARY CONTAINMENT VENT SYSTEM (APCVS) FLOW DIAGRAM UNIT 2
FIGURE 6.2-59



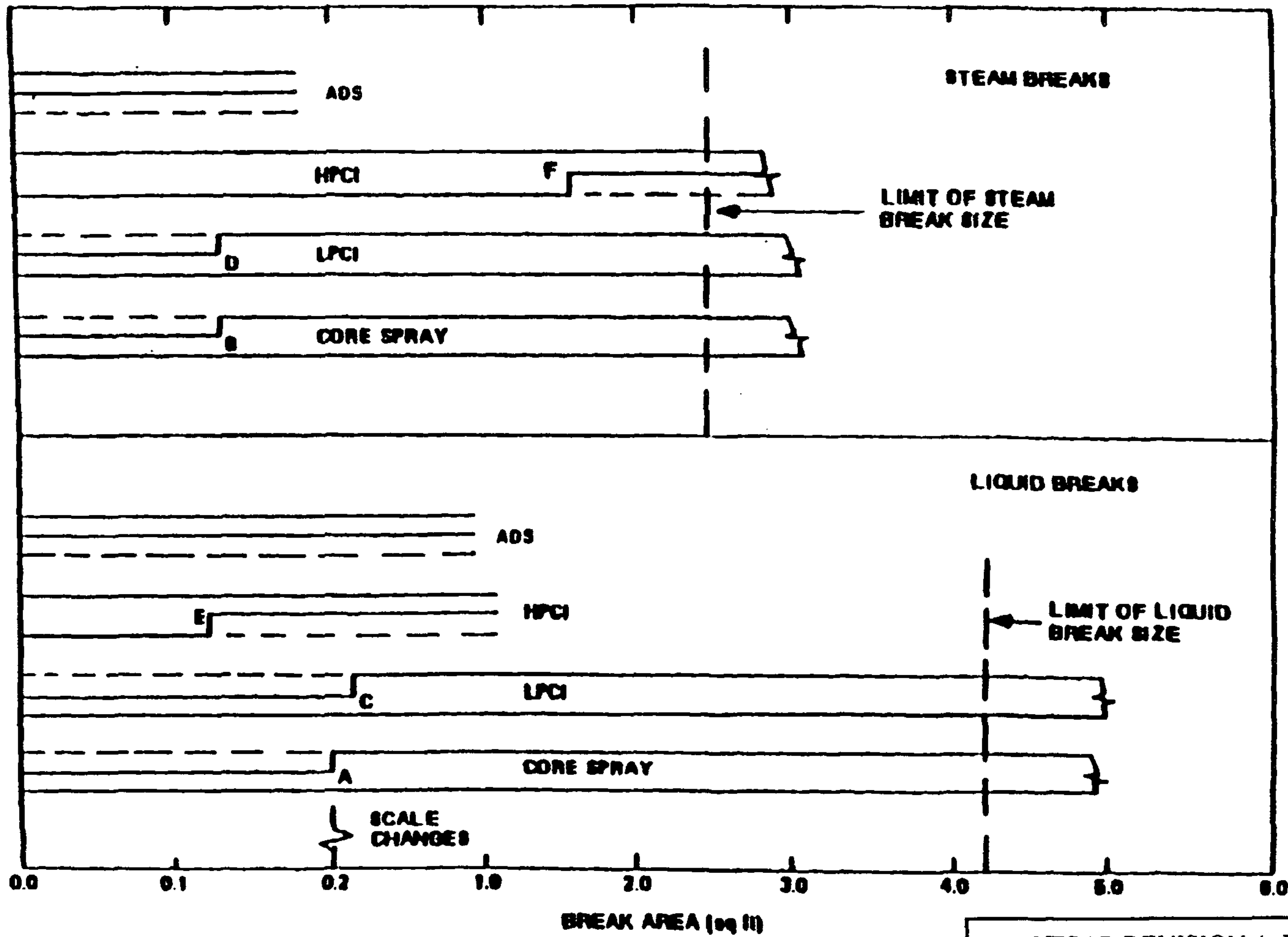
FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001

DRESDEN STATION
UNITS 2 & 3

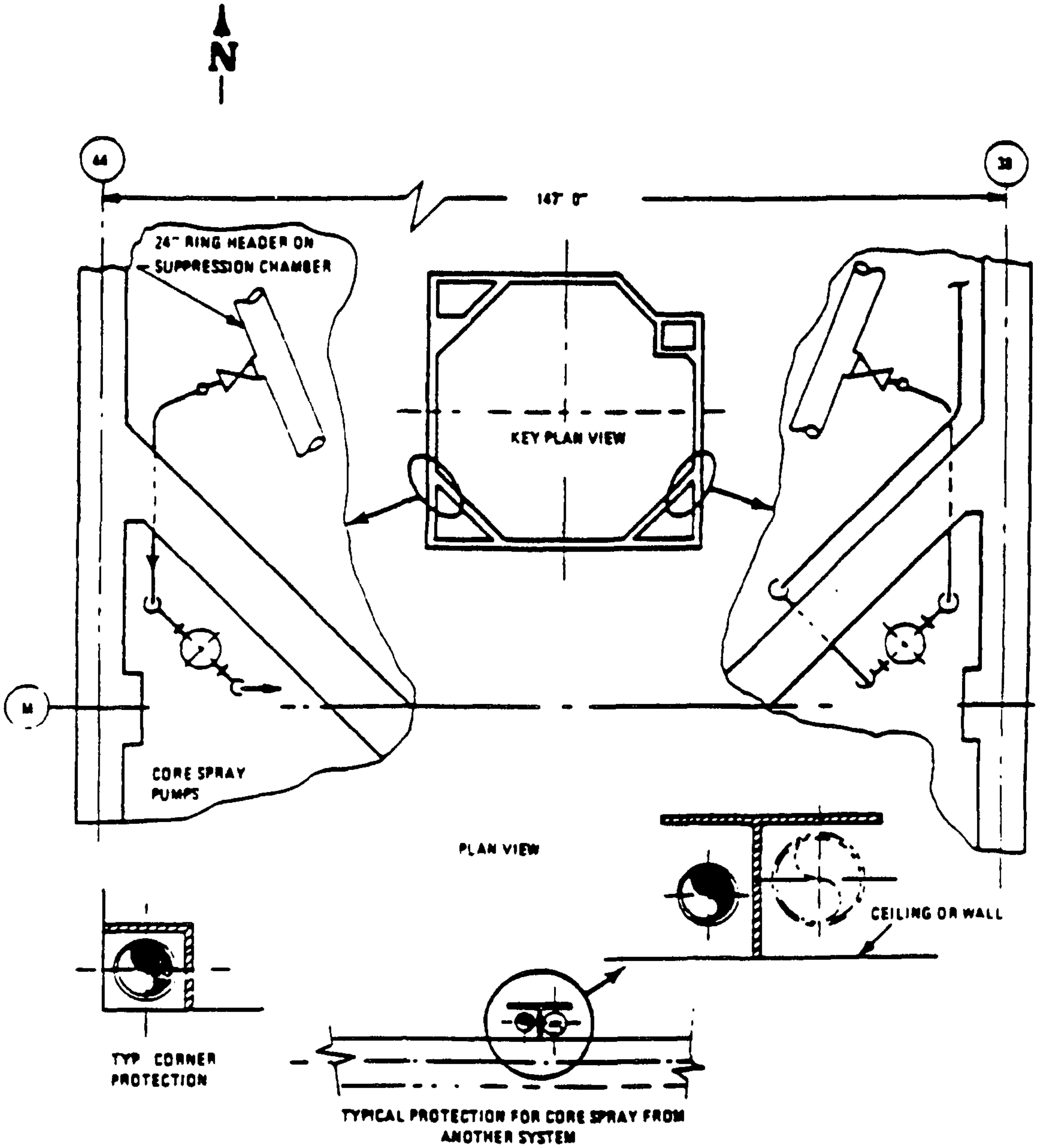
AUGUMENTED PRIMARY CONTAINMENT VENT SYSTEM (APCVS) FLOW DIAGRAM - UNIT 3

FIGURE 6.2-60



HISTORICAL INFORMATION

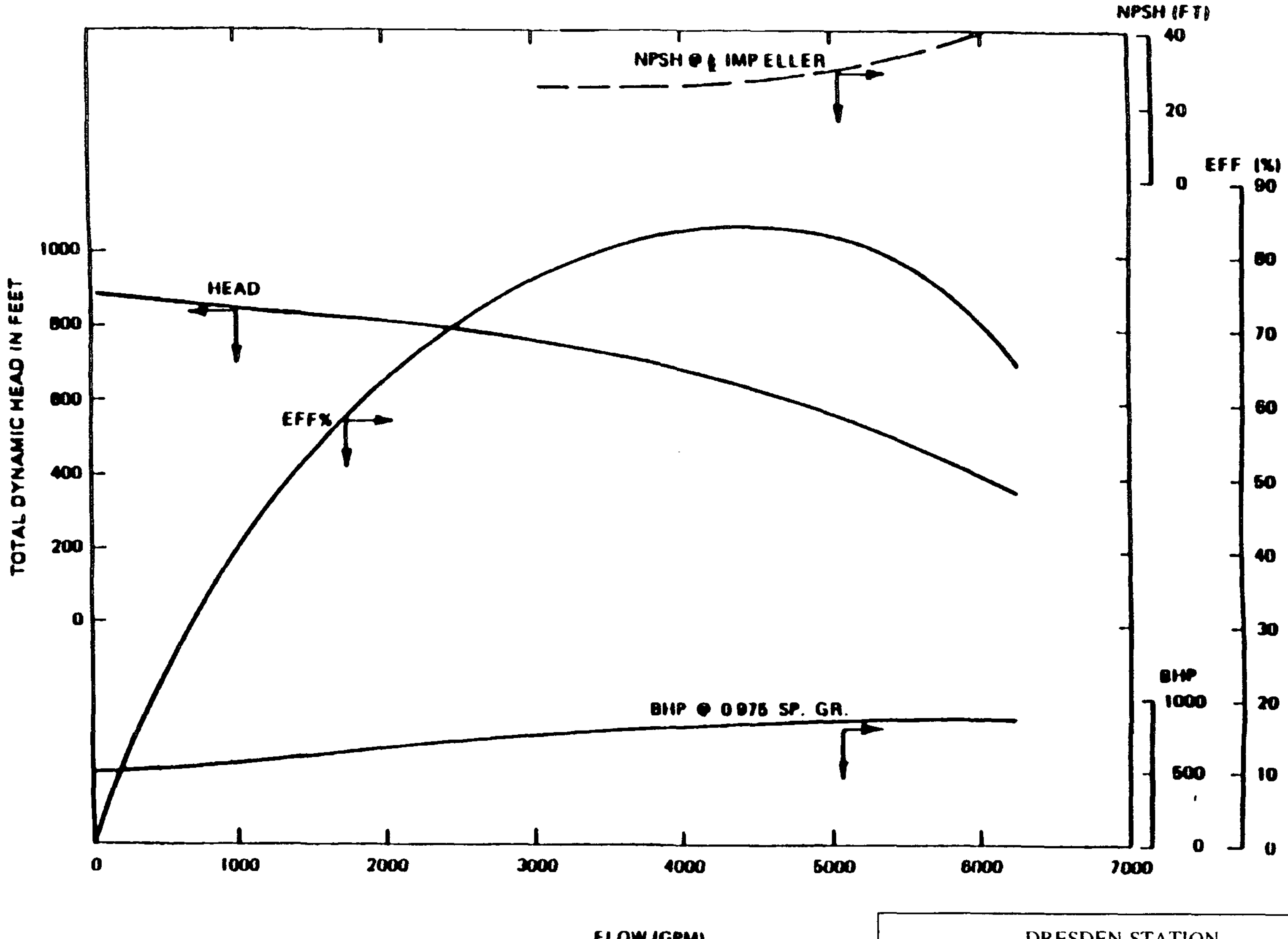
UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
EMERGENCY CORE COOLING SYSTEM VERSUS BREAK SPECTRUM
FIGURE 6.3-1



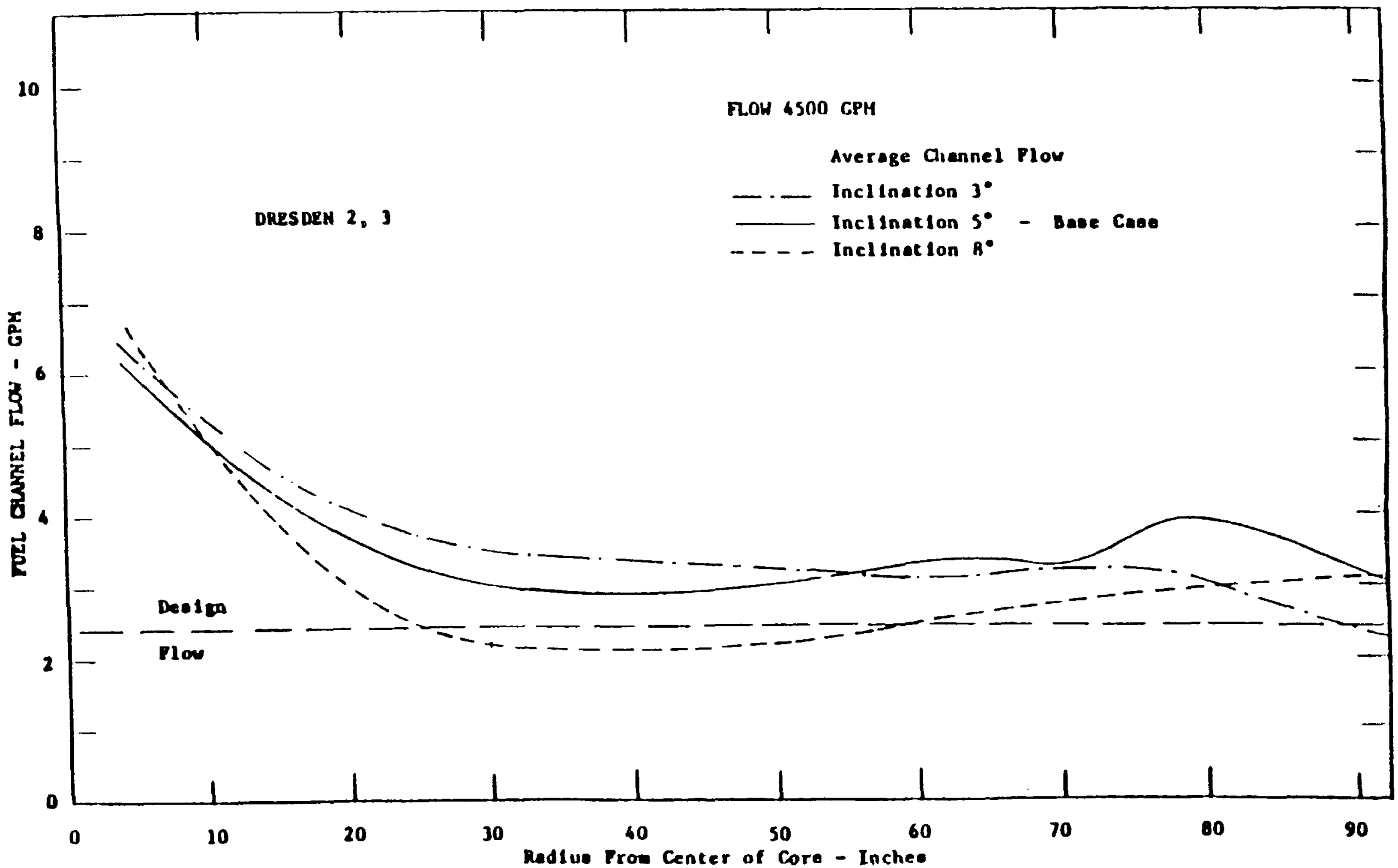
DRESDEN STATION
UNITS 2 & 3

CORE SPRAY PIPE PROTECTION

FIGURE 6.3-3



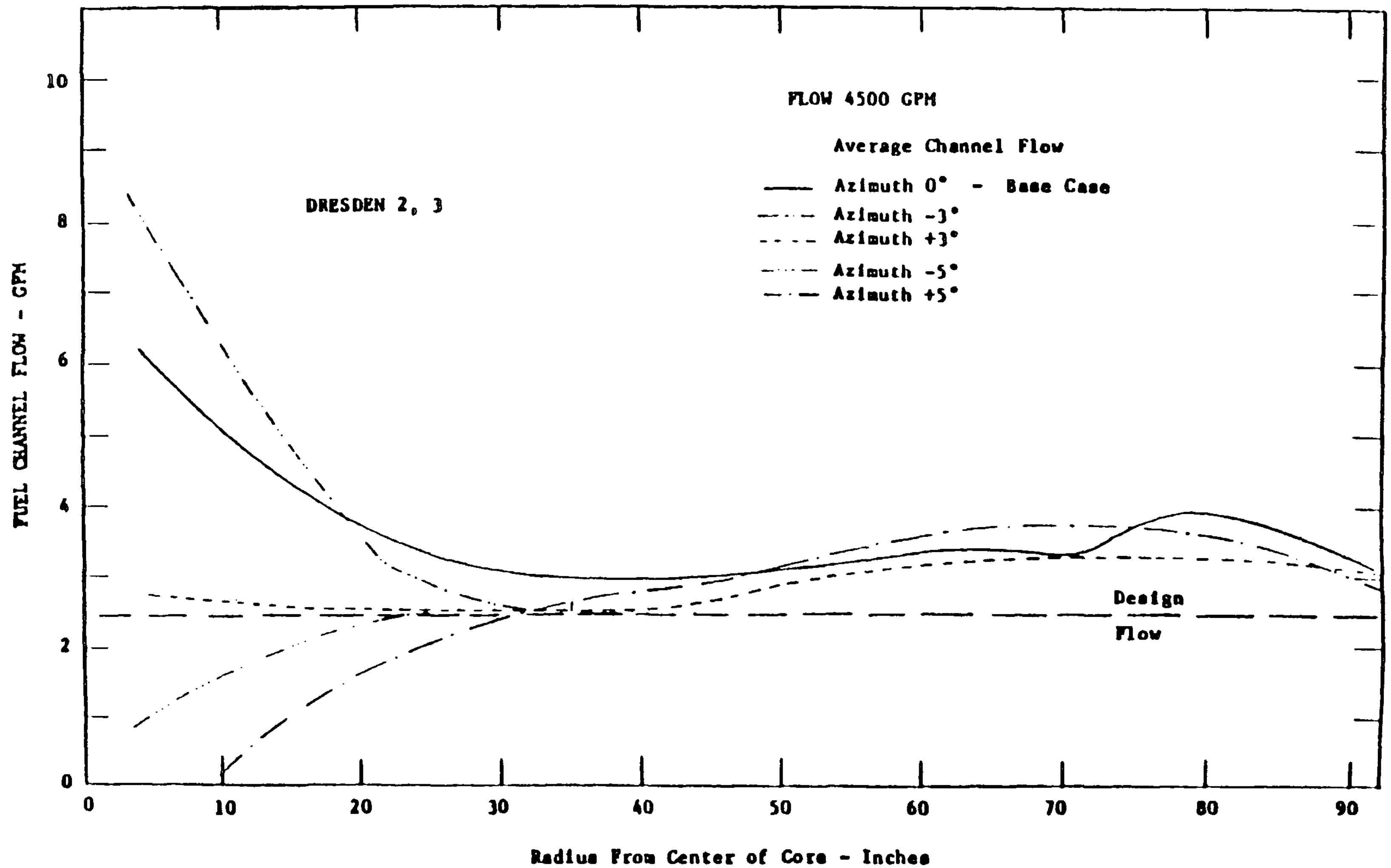
DRESDEN STATION UNITS 2 & 3
CORE SPRAY COOLING SYSTEM PUMP CHARACTERISTICS
FIGURE 6.3-4



DRESDEN STATION
UNITS 2 & 3

CORE SPRAY DISTRIBUTION
EFFECT OF OPEN ELBOW INCLINATION
(LOWER HEADER)

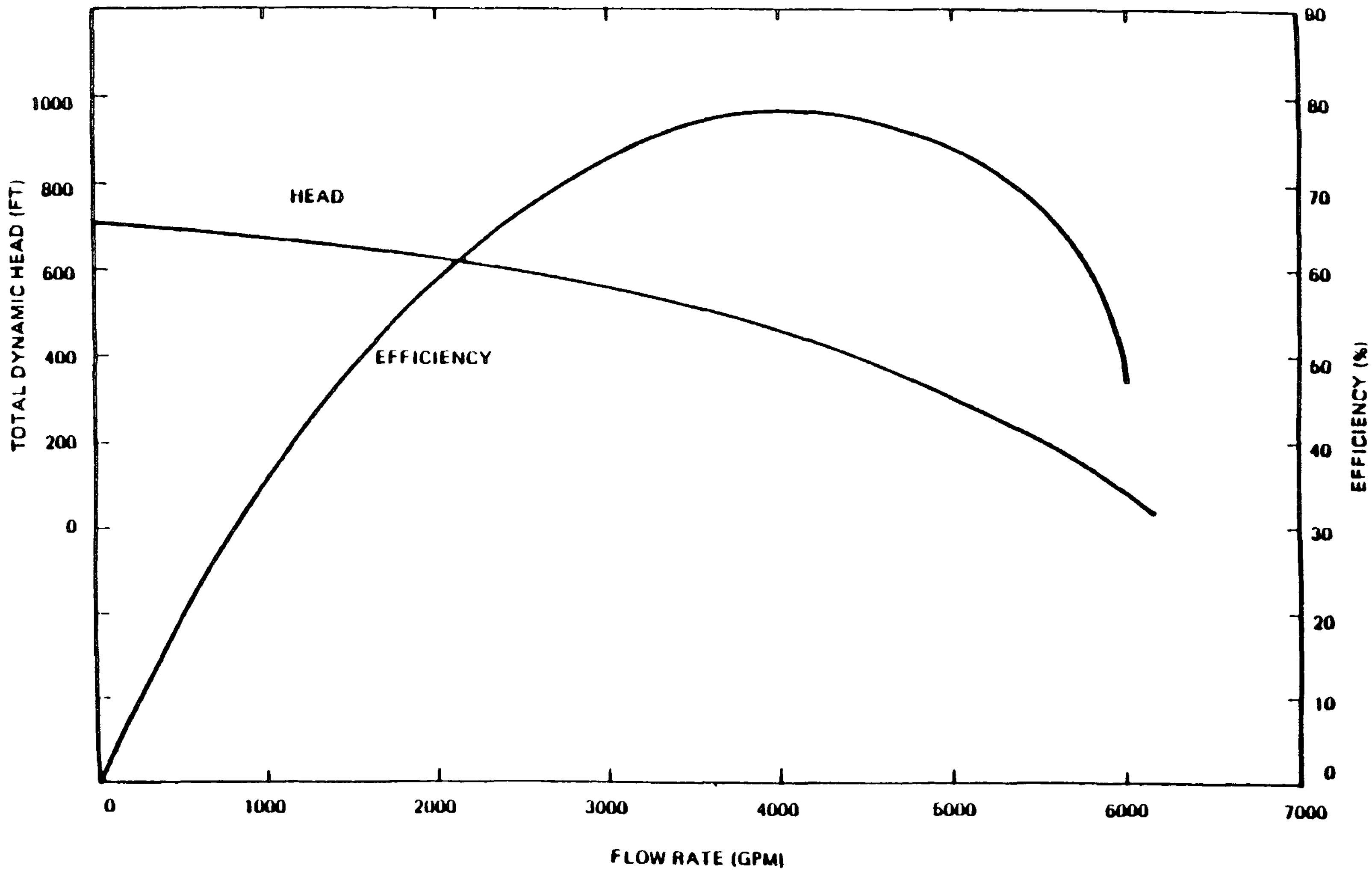
FIGURE 6.3-5



DRESDEN STATION
UNITS 2 & 3

CORE SPRAY DISTRIBUTION
EFFECT OF OPEN ELBOW AZIMUTH
(LOWER HEADER)

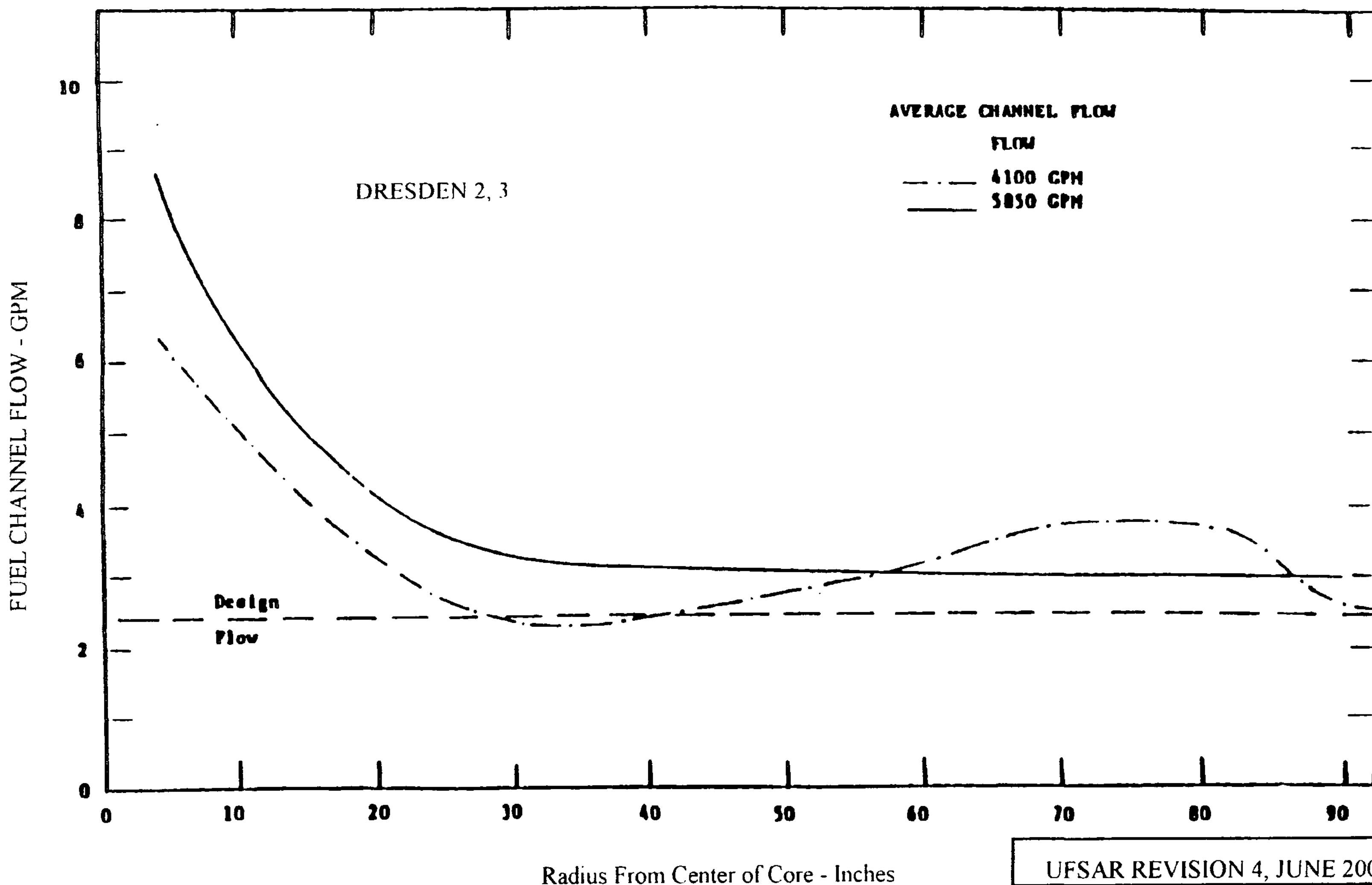
FIGURE 6.3-6



DRESDEN STATION
UNITS 2 & 3

LOW PRESSURE COOLANT INJECTION /
CONTAINMENT COOLING
PUMP CHARACTERISTICS

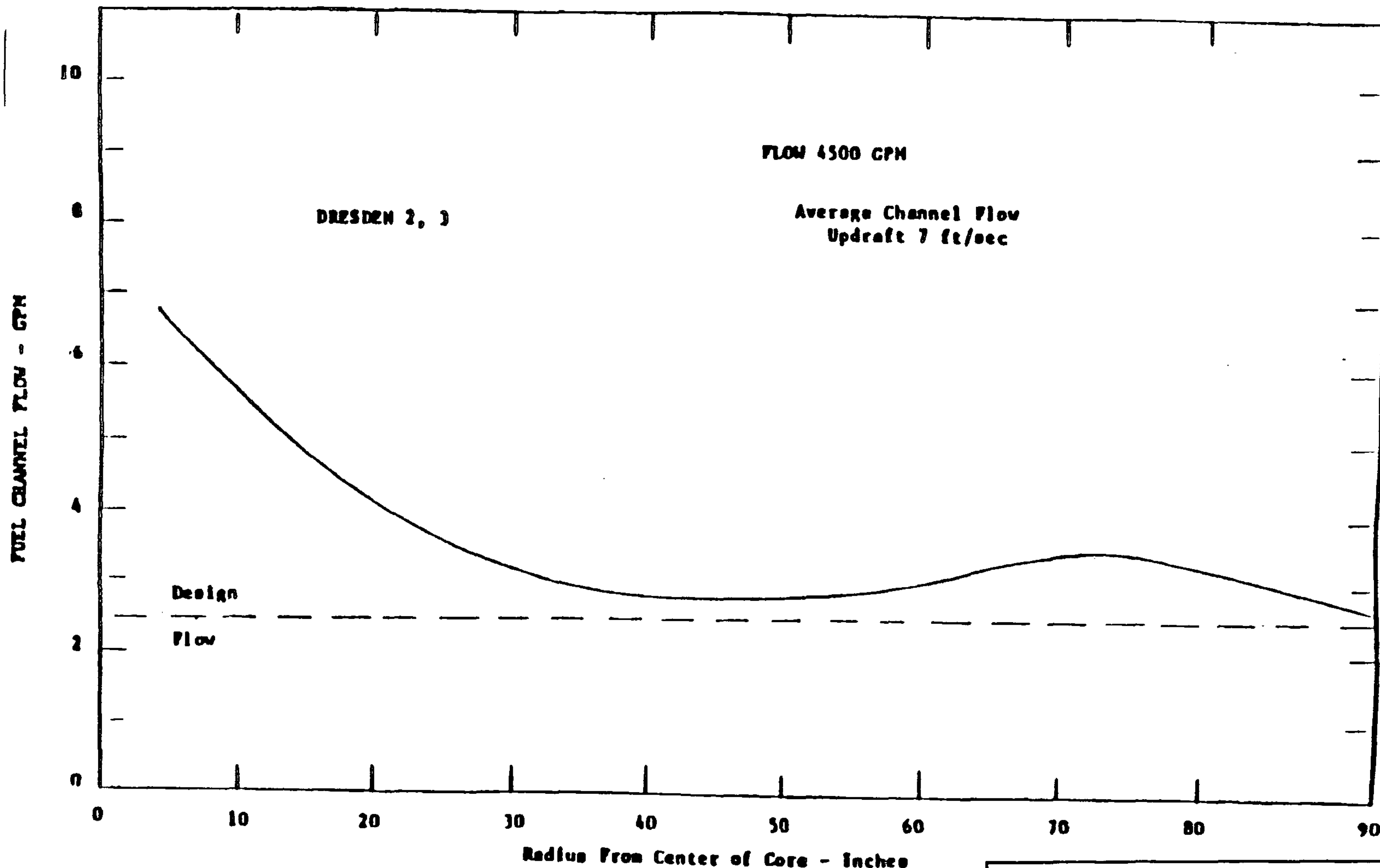
FIGURE 6.3-8



Historical Information

FOR INFORMATION ONLY

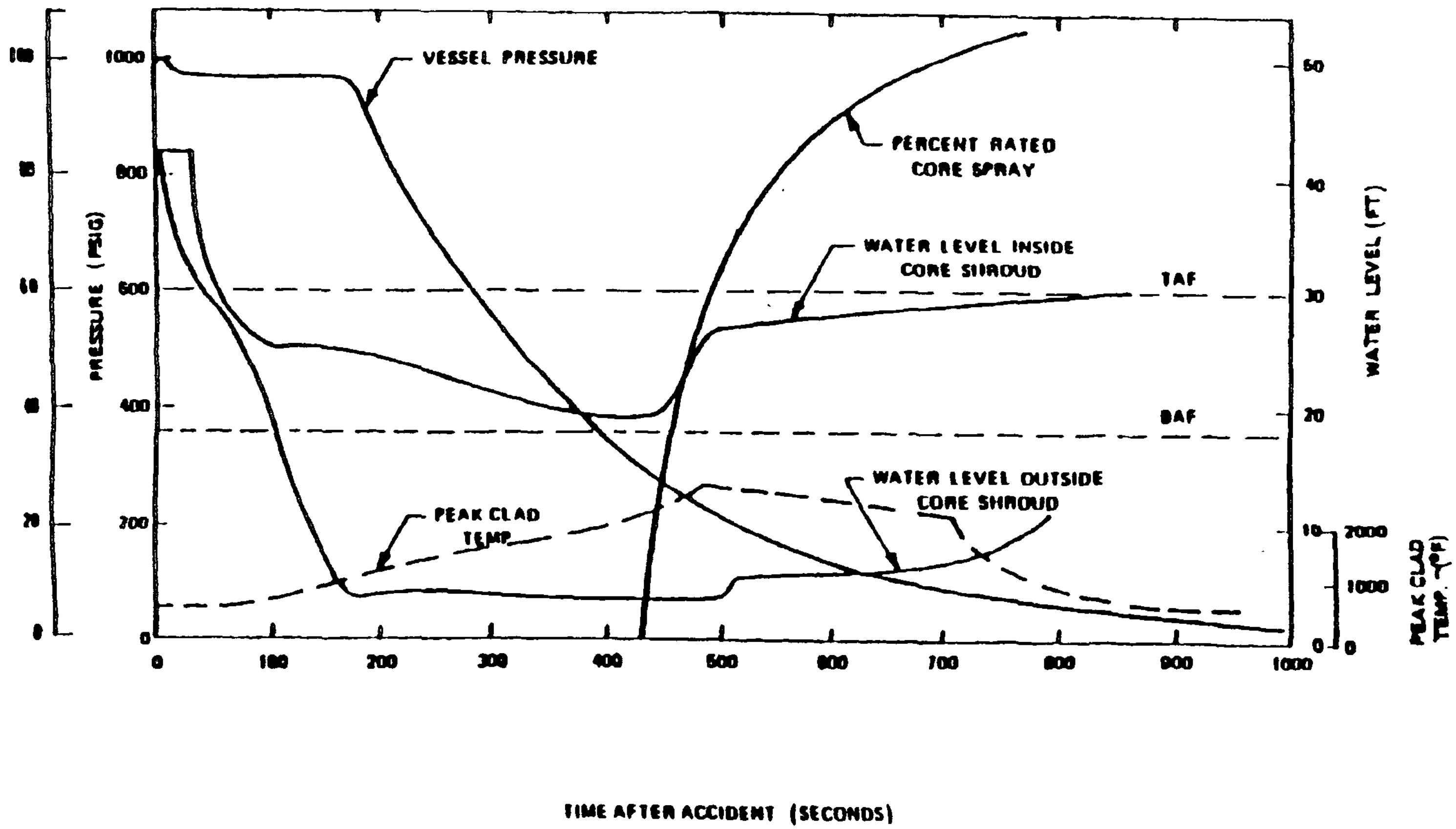
UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
CORE SPRAY DISTRIBUTION EFFECT OF TOTAL FLOWRATE (LOWER HEADER)
FIGURE 6.3-10



Historical Information

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
CORE SPRAY DISTRIBUTION EFFECT OF UPDRAFT (LOWER HEADER)
FIGURE 6.3-11

FOR INFORMATION ONLY



Historical Information

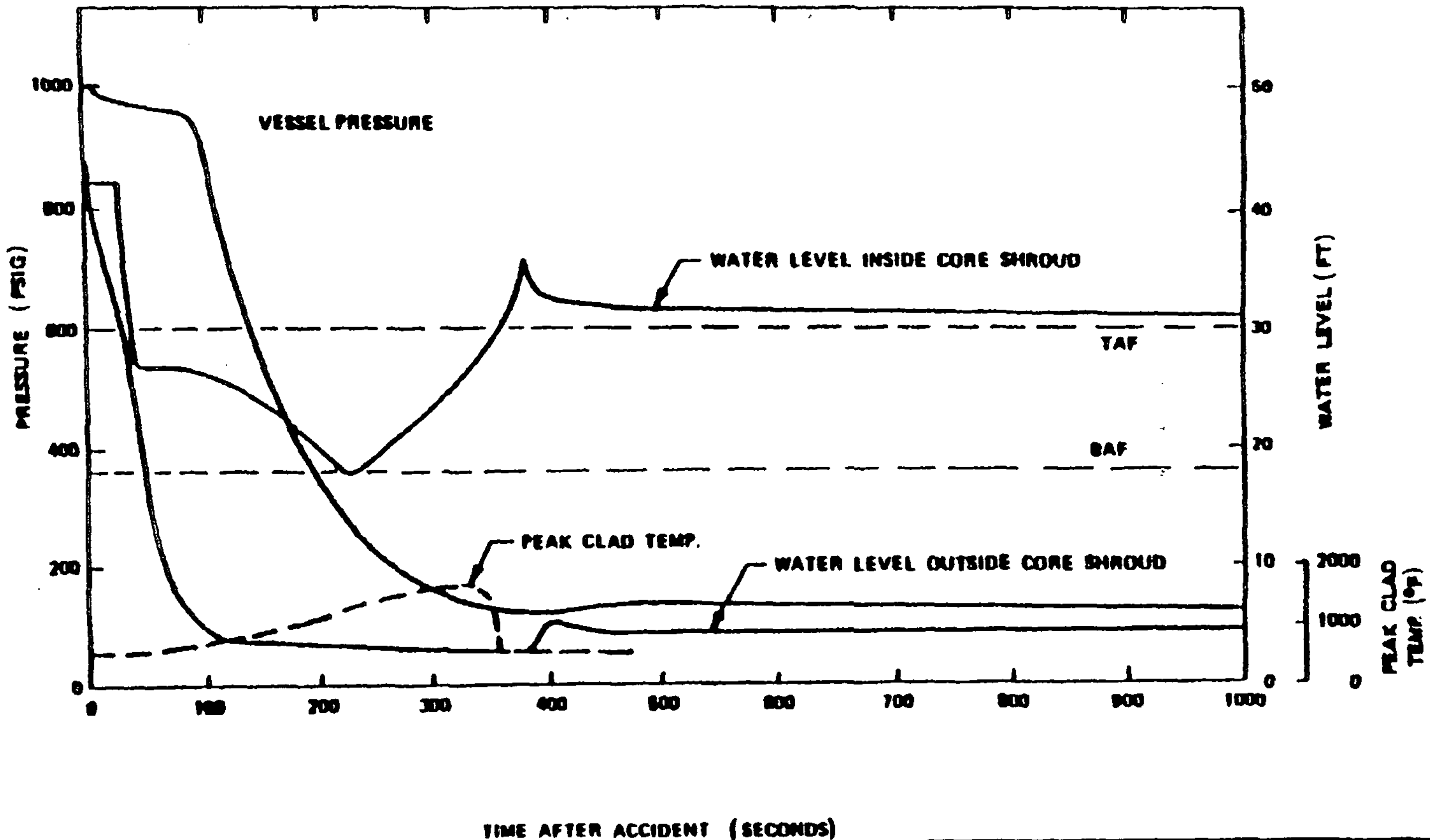
FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001

DRESDEN STATION
UNITS 2 & 3

UNASSISTED CORE SPRAY PERMORMANCE
($0.2\ ft.^2$ BREAK AREA)

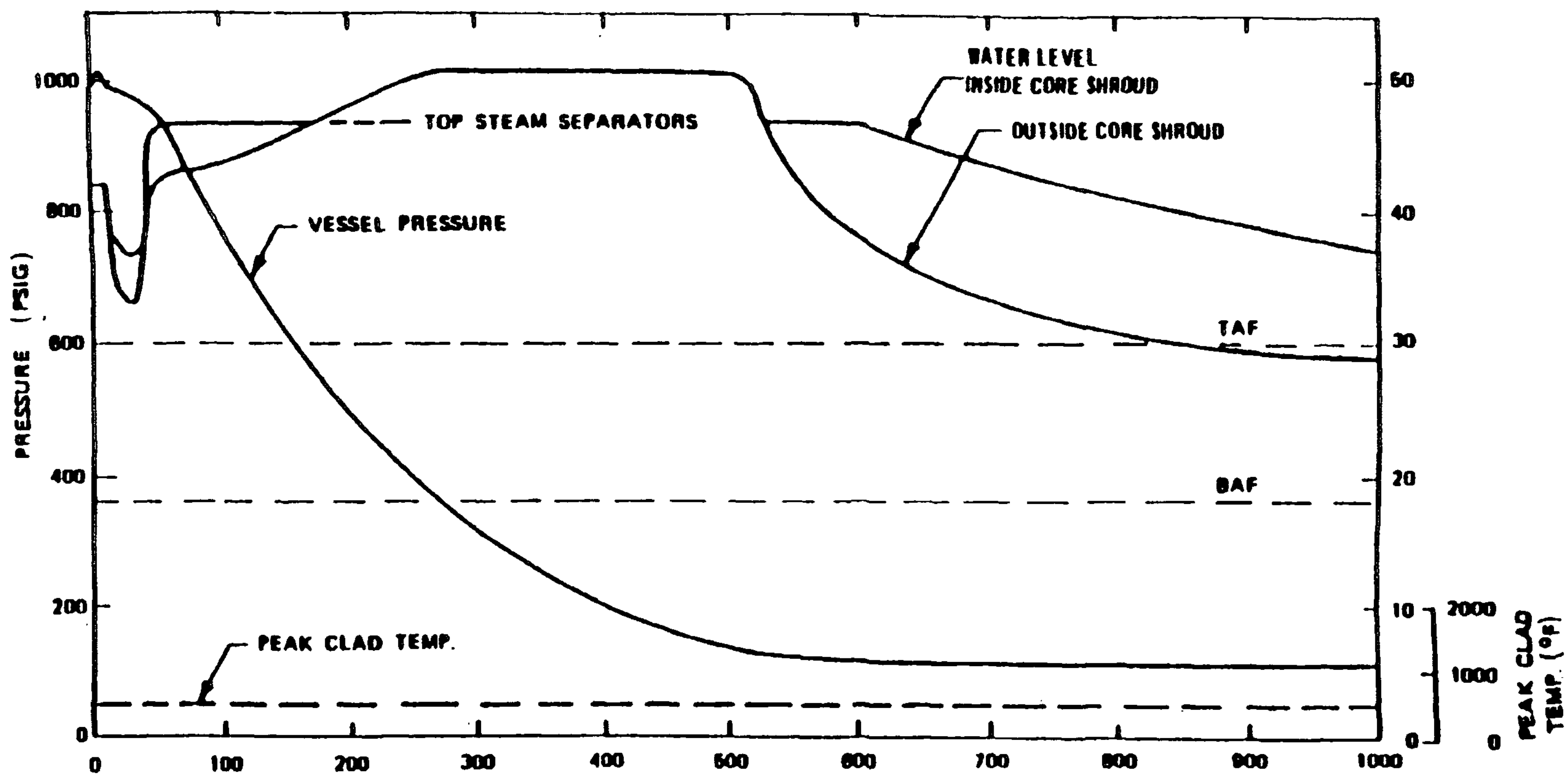
FIGURE 6.3-12



Historical Information

FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
UNASSISTED LPCI PERFORMANCE (0.4 ft.^{2} BREAK AREA)
FIGURE 6.3-13



Historical Information

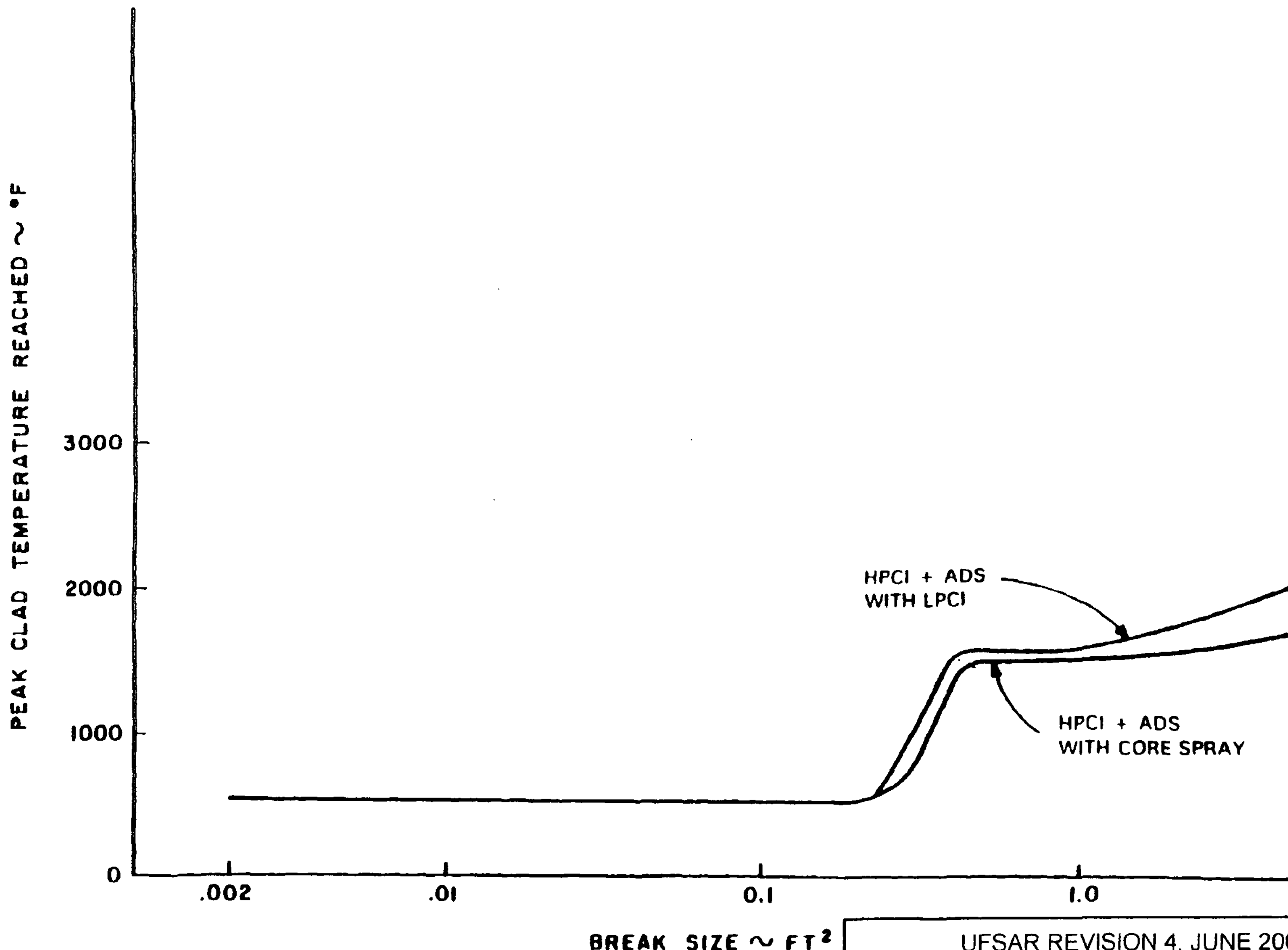
UFSAR REVISION 4, JUNE 2001

DRESDEN STATION
UNITS 2 & 3

UNASSISTED HPCI PERFORMANCE
(0.1 ft.^{2} BREAK AREA)

FIGURE 6.3-14

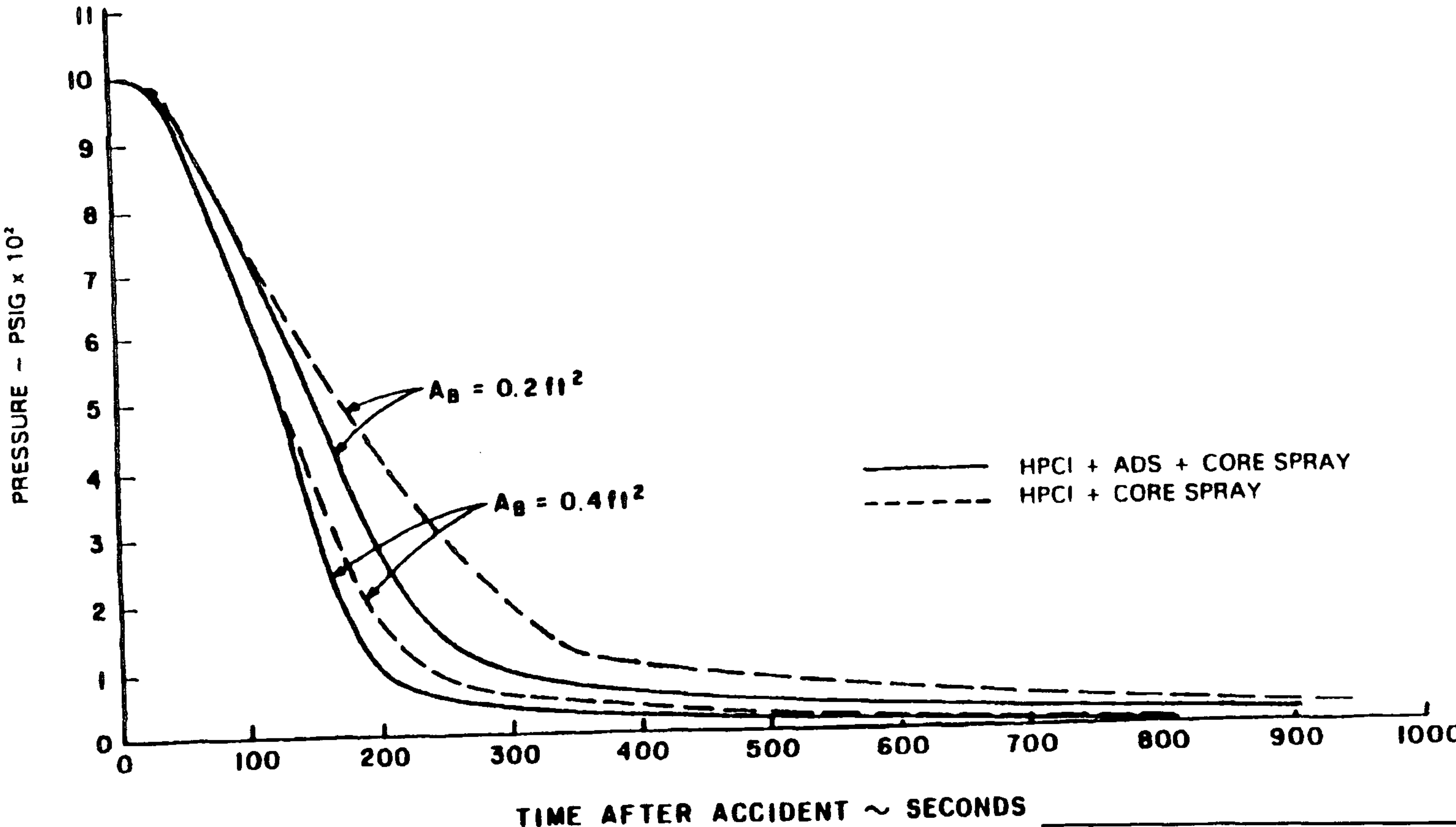
FOR INFORMATION ONLY



Historical Information

FOR INFORMATION ONLY

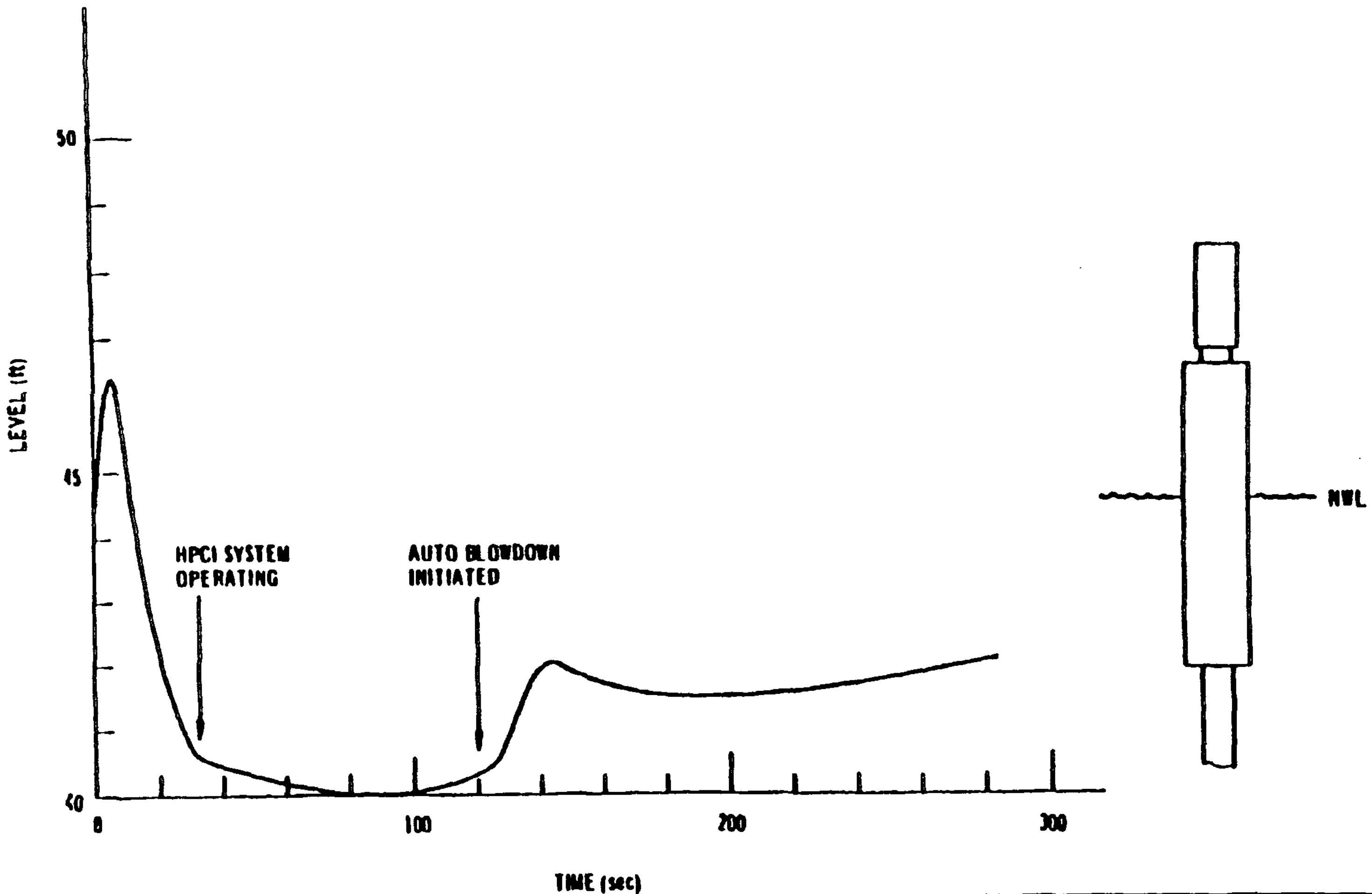
UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
PEAK CLAD TEMPERATURE, HPCI AND ADS WITH CORE SPRAY OR LPCI
FIGURE 6.3-15



Historical Information

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
DEPRESSURIZATION RATE, HPCI AND ADS WITH CORE SPRAY
FIGURE 6.3-16

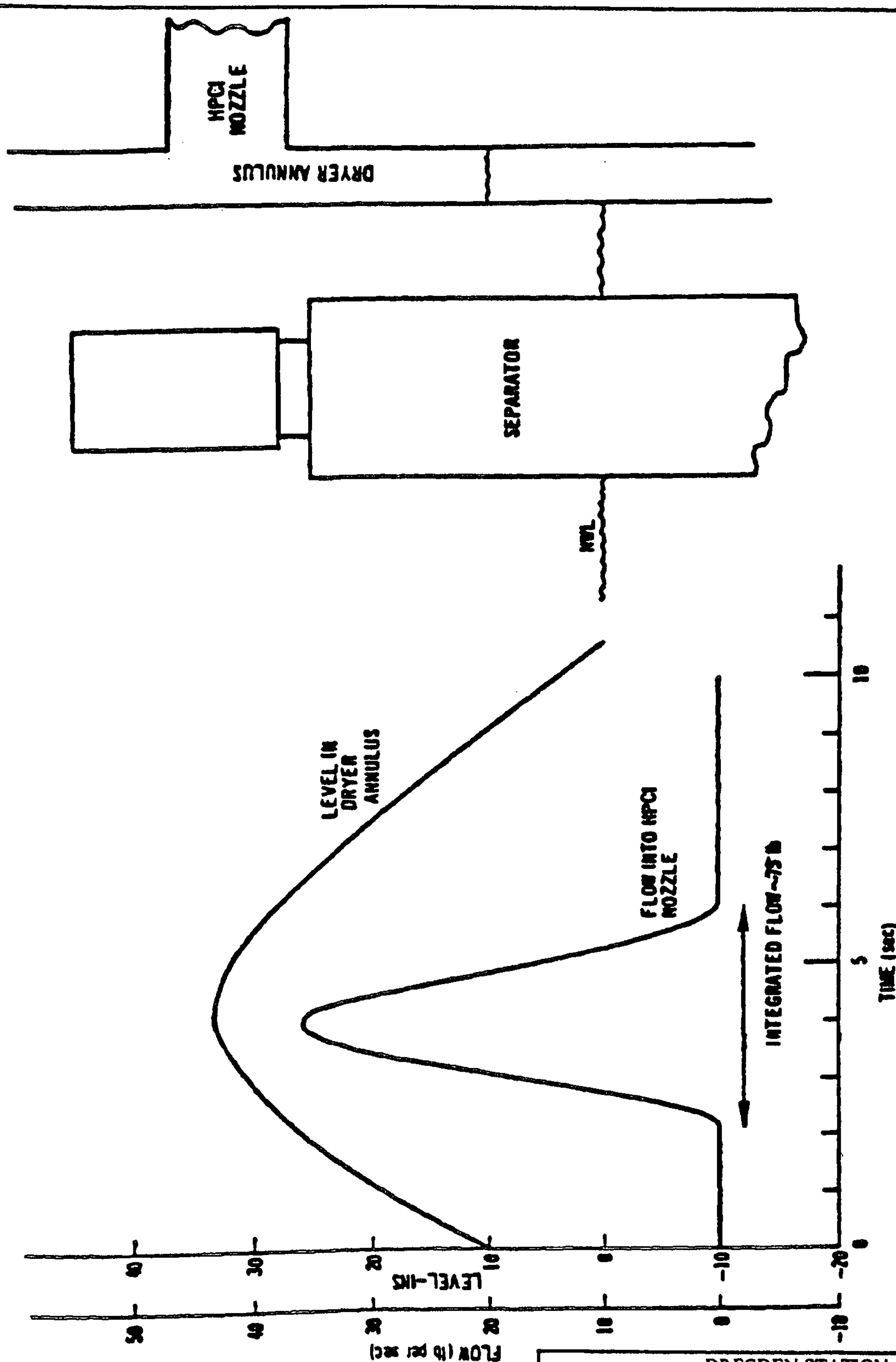
FOR INFORMATION ONLY



Historical Information

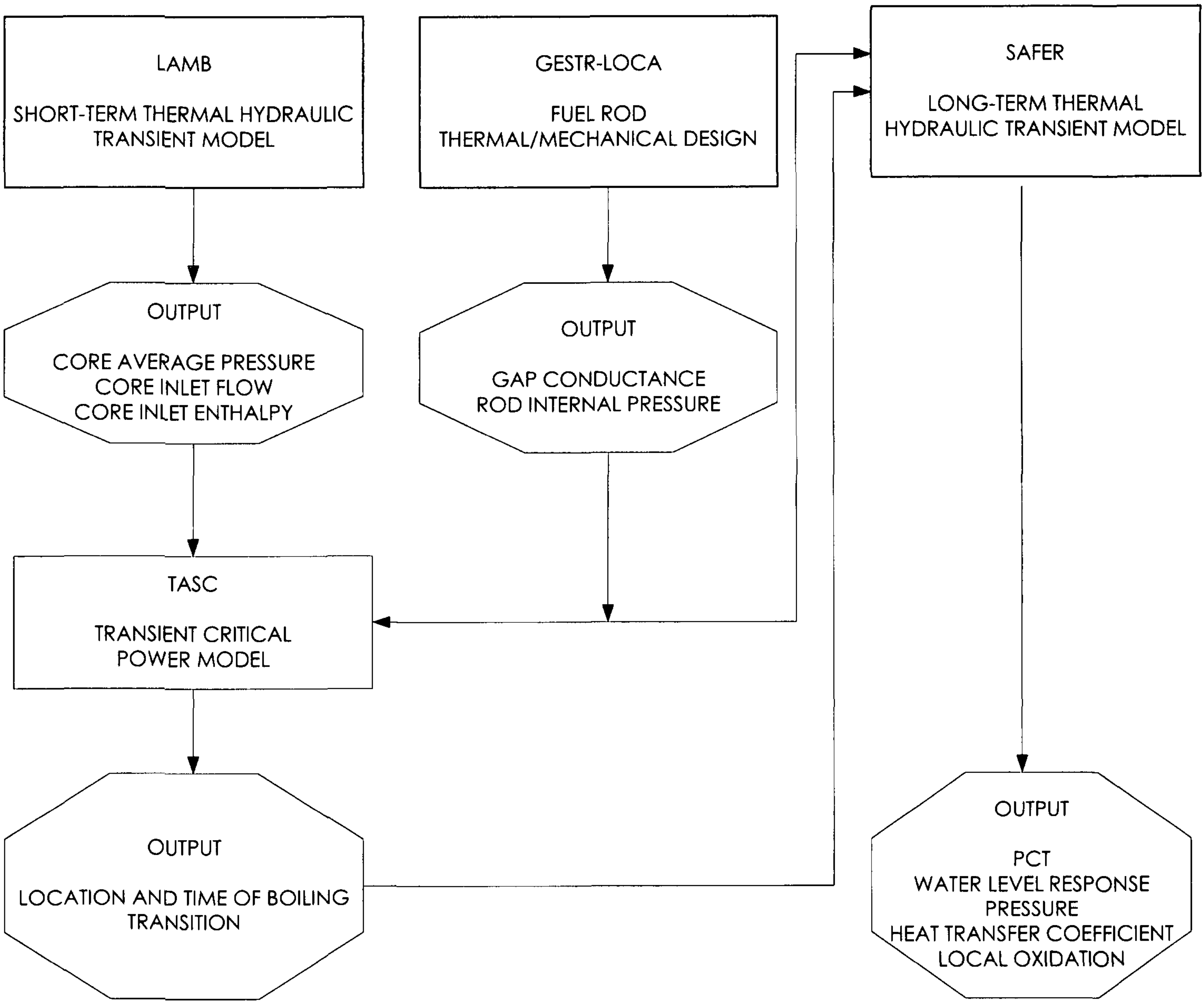
FOR INFORMATION ONLY

UFSAR REVISION 4, JUNE 2001
DRESDEN STATION UNITS 2 & 3
LEVEL TRANSIENT FOLLOWING A 0.2 $ft.^2$ STEAM BREAK (BOTH HPCI AND ADS INITIATED)
FIGURE 6.3-17



HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
LEVEL TRANSIENT AND FLOW TO HPCI NOZZLE FOLLOWING A 0.2 FT^2 STEAM BREAK AT 2527 MWT
FIGURE 6.3-18 REVISION 5, JANUARY 2003

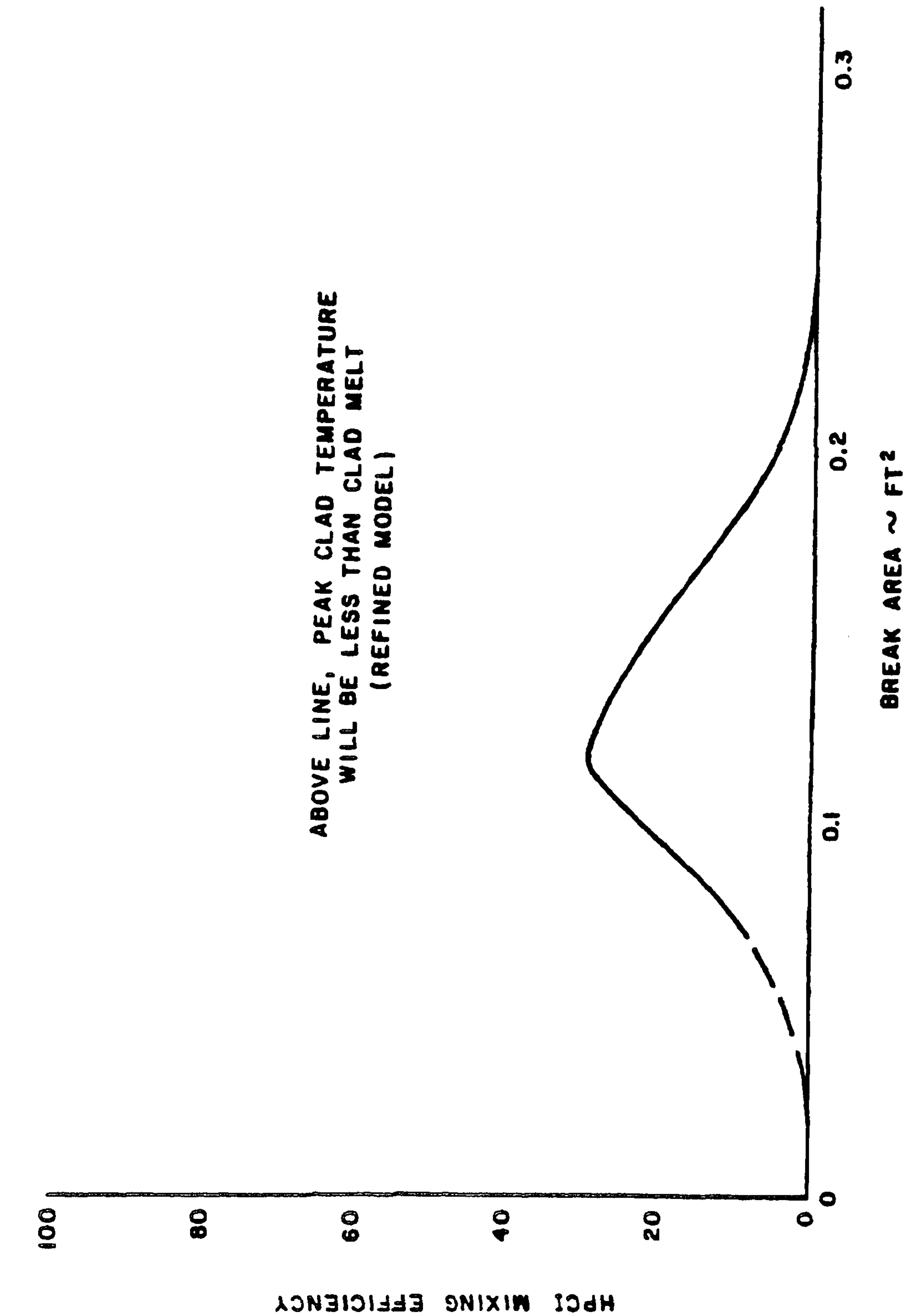


UFSAR REVISION 6, JUNE 2005

DRESDEN STATION
UNITS 2 & 3

GE SAFER/GESTR LOCA ANALYSIS MODEL

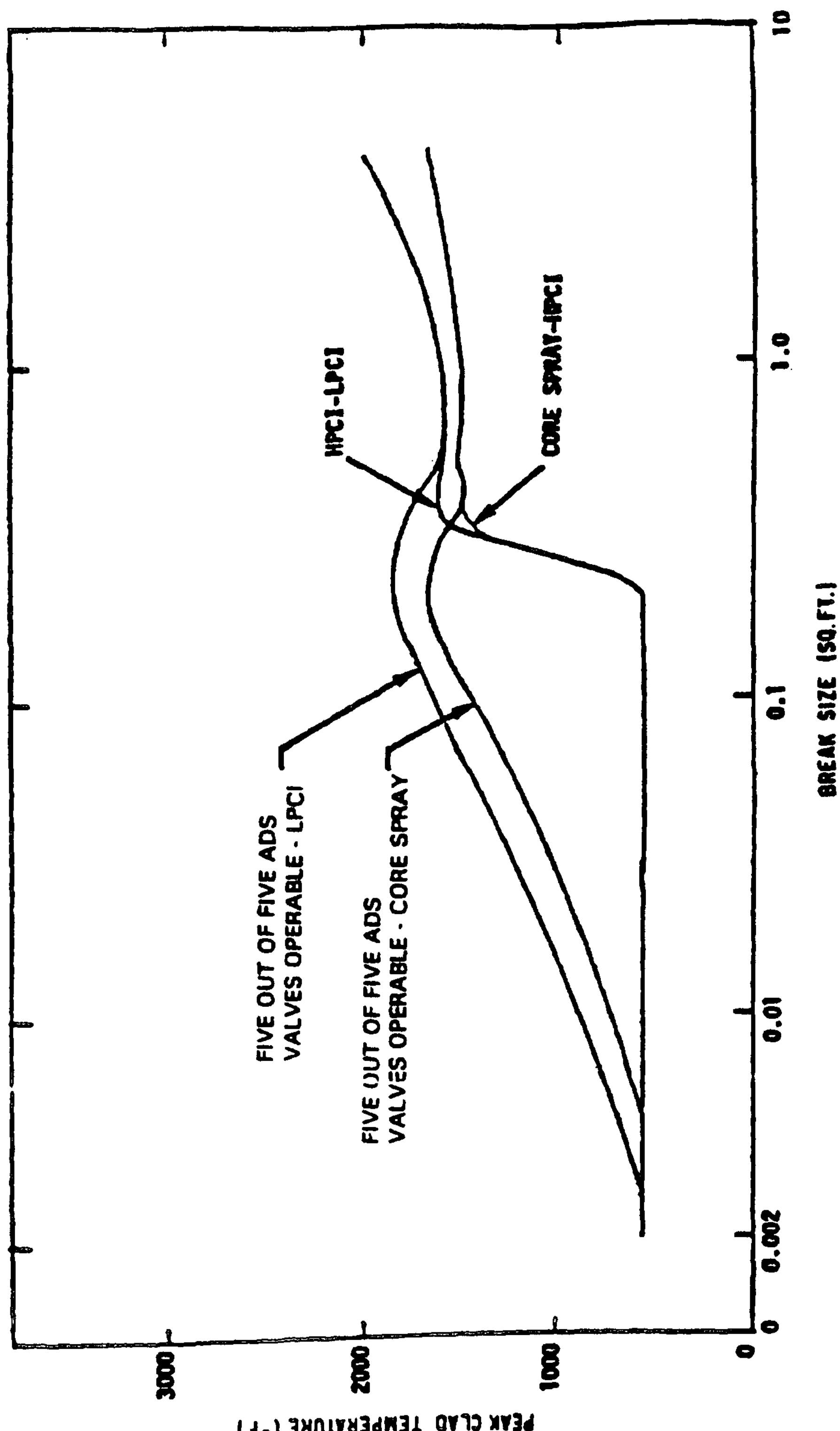
FIGURE 6.3-19b



HISTORICAL

This figure contains historical information only.

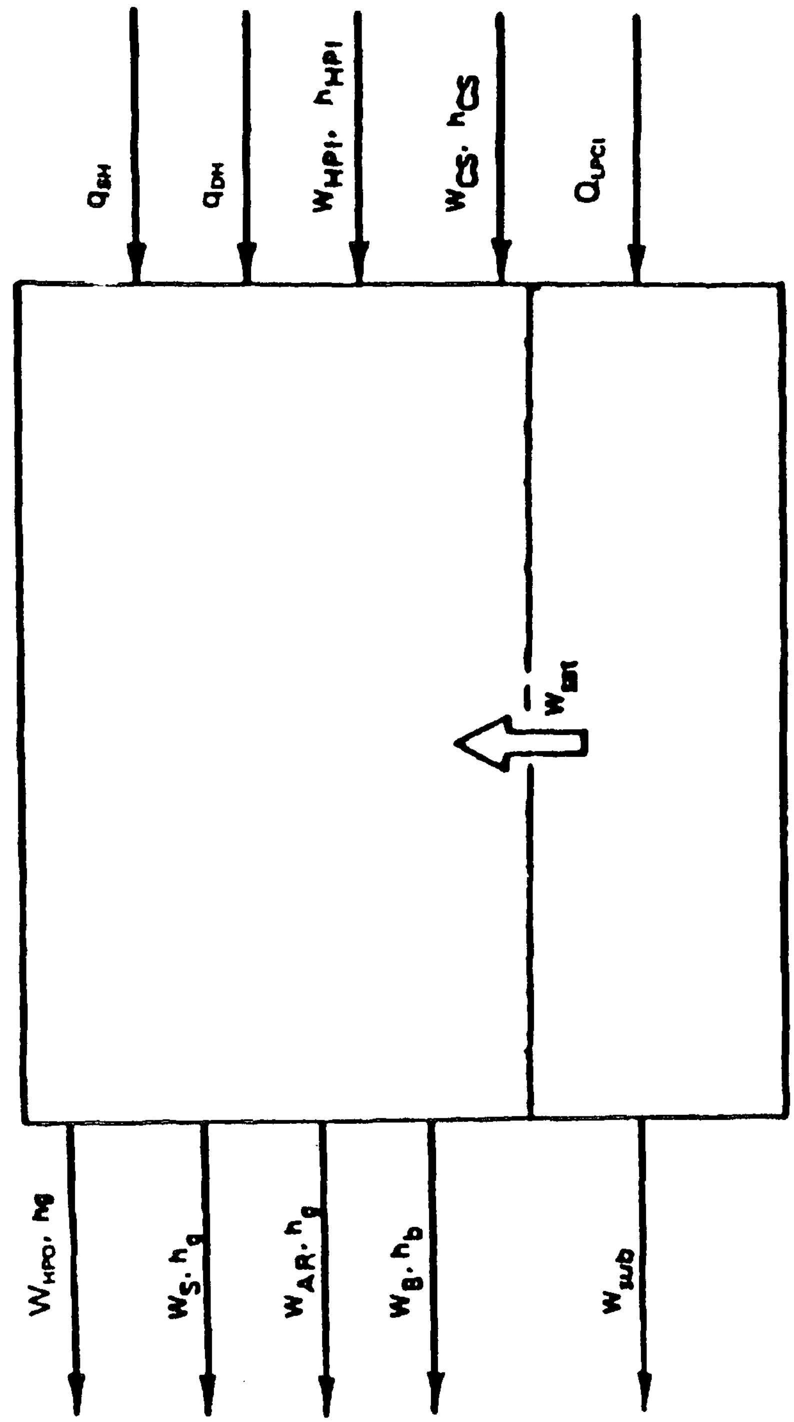
DRESDEN STATION UNITS 2 & 3
REQUIRED HPCI MIXING EFFICIENCY VS. LIQUID BREAK AREA (FT^2) TO PREVENT CLAD MELT AT 2527 MWT (HPCI – LPCI ONLY)
FIGURE 6.3-20 REVISION 5, JANUARY 2003



HISTORICAL

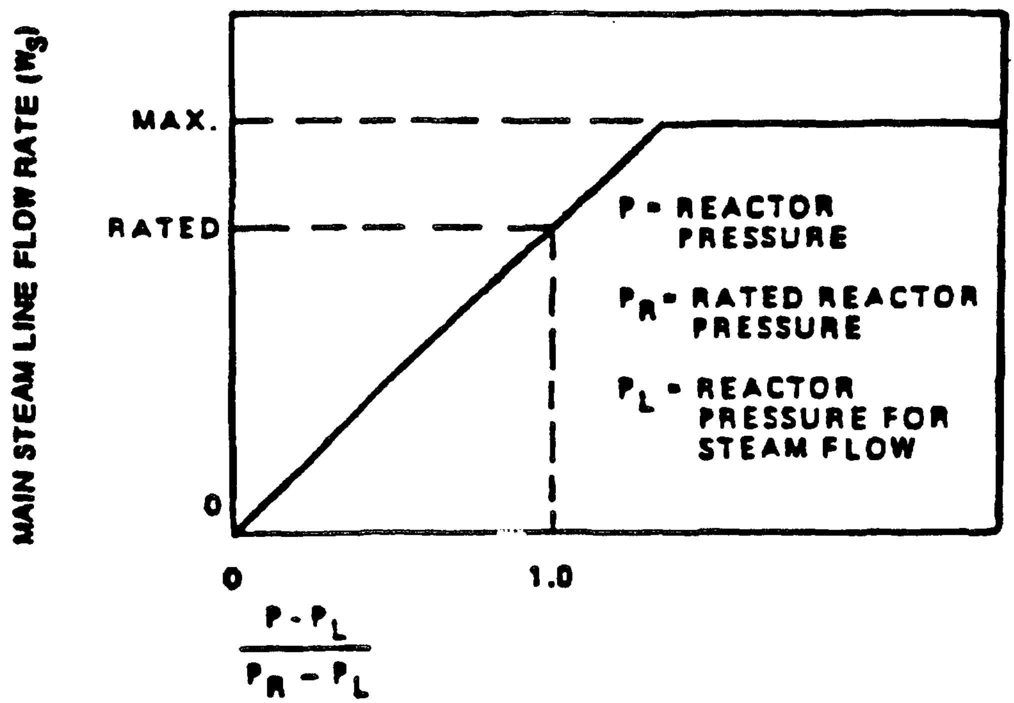
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
PEAK CLAD TEMPERATURE VS. LIQUID BREAK SIZE AT 2527 MWT
FIGURE 6.3-21 REVISION 5, JANUARY 2003



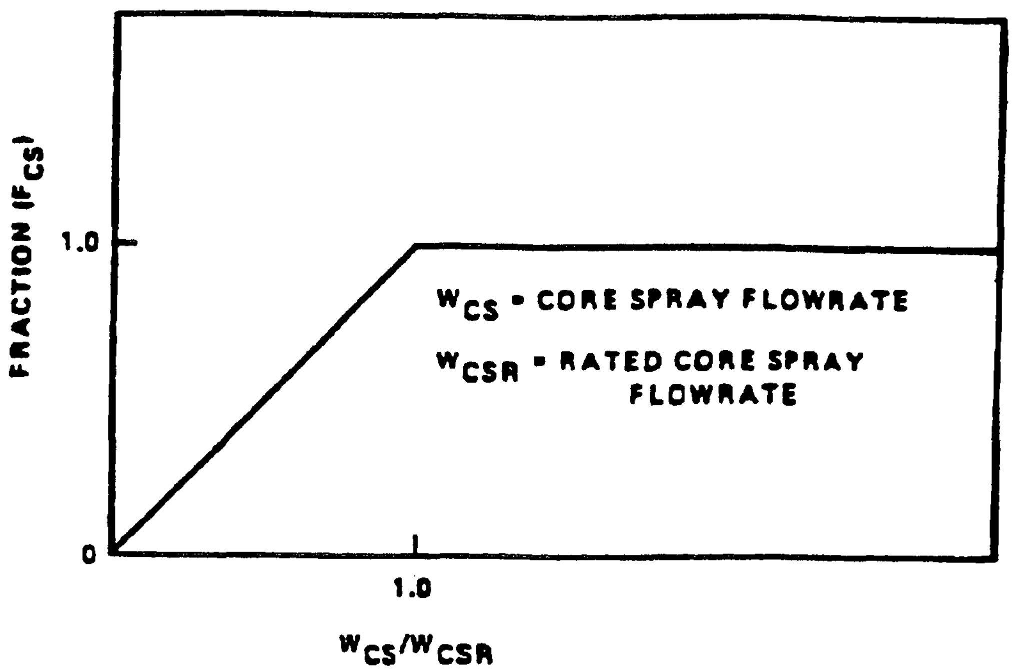
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
BREAK ANALYSIS MODEL – FLOW IN AND OUT OF REACTOR AT 2527 MWT
FIGURE 6.3-22 REVISION 5, JANUARY 2003



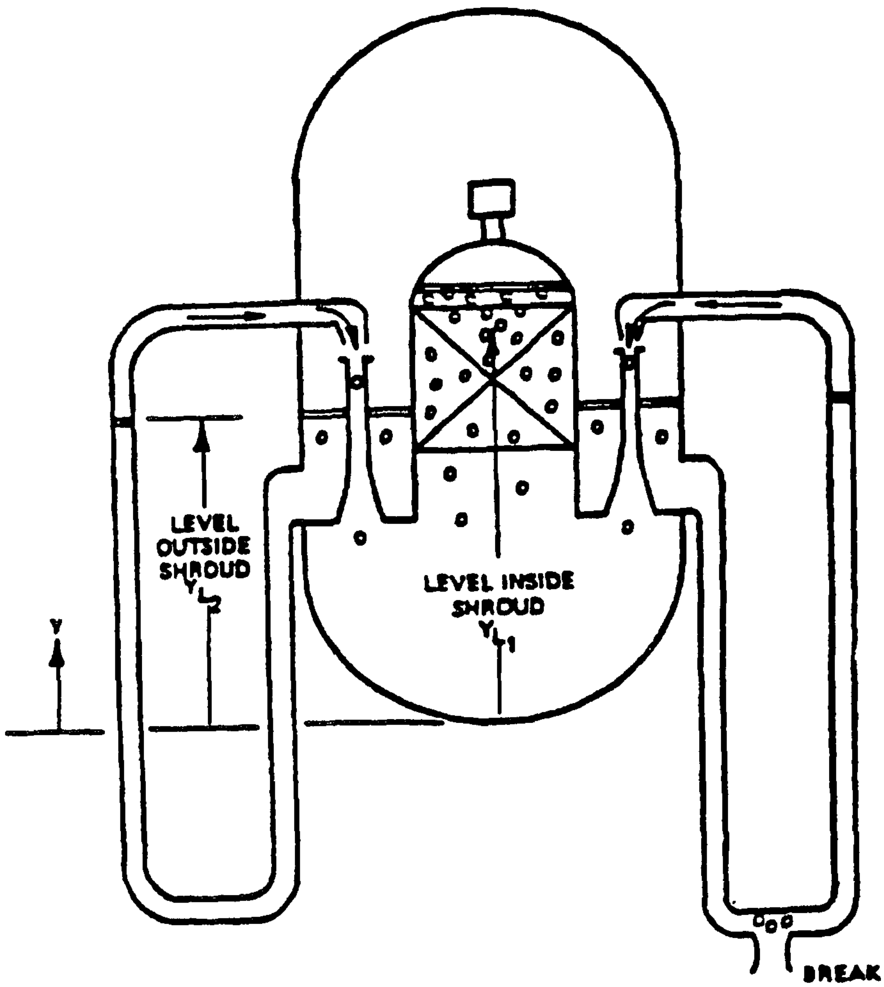
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
MAIN STEAM FLOW SIMULATION MODEL AT 2527 MWT
FIGURE 6.3-23
REVISION 5, JANUARY 2003



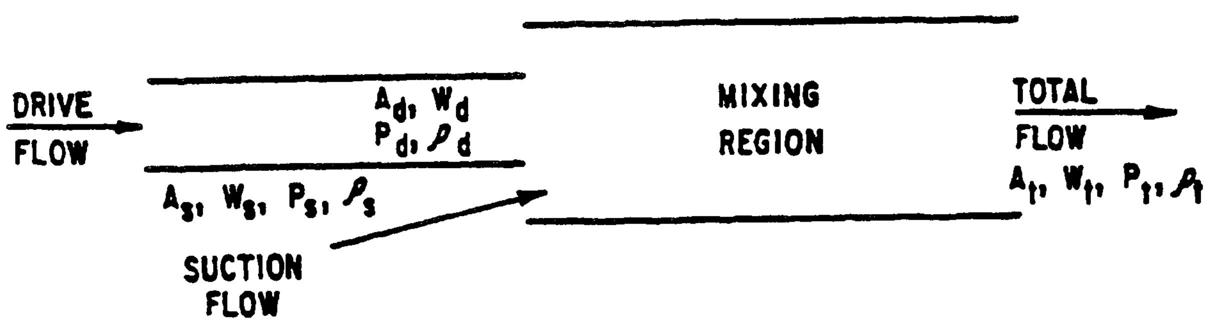
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE SPRAY DECAY HEAT REMOVAL MODEL AT 2527 MWT
FIGURE 6.3-24
REVISION 5, JANUARY 2003



HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
REACTOR COOLANT LEVEL SWELL AT 2527 MWT
FIGURE 6.3-25
REVISION 5, JANUARY 2003



A - AREA

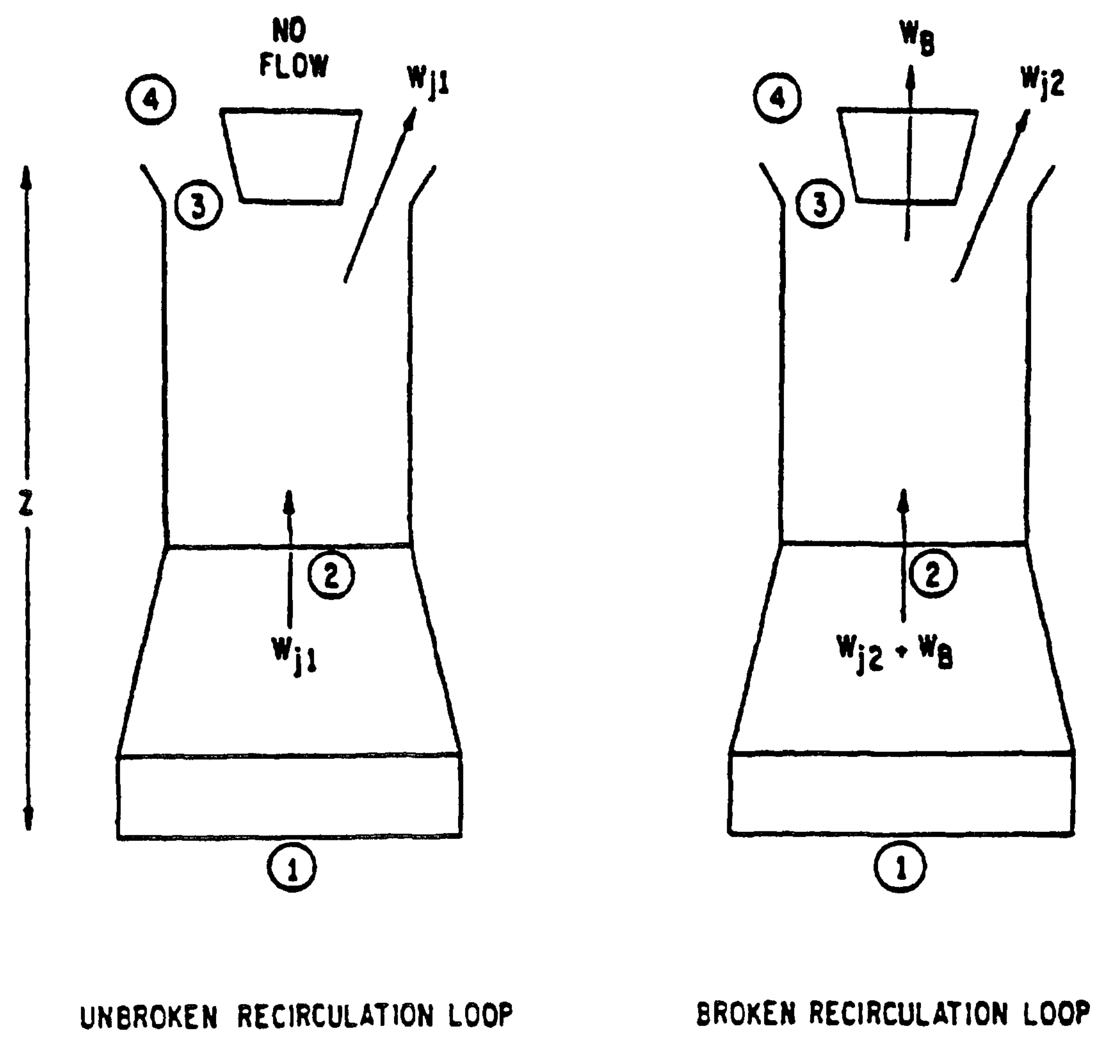
W - MASS FLOW RATE

P - PRESSURE

ρ - DENSITY

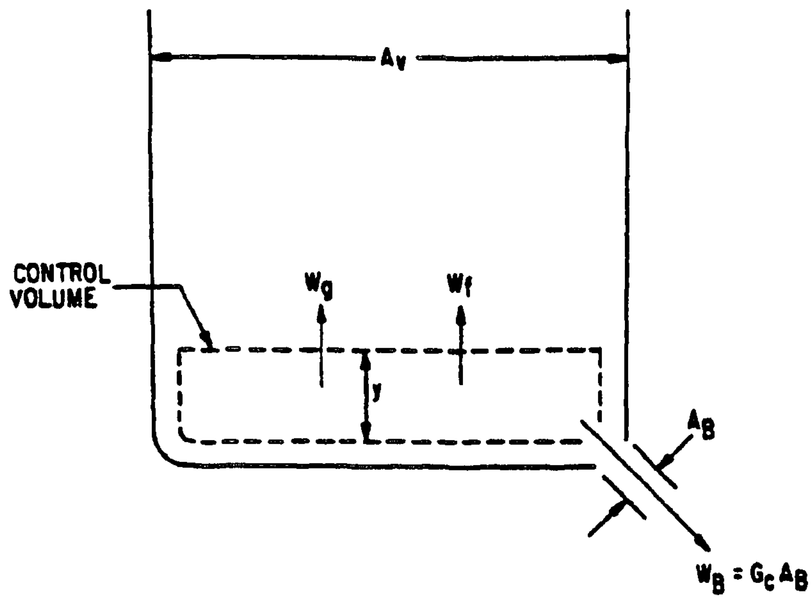
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
JET PUMP MODEL FOR TRANSIENT ANALYSIS AT 2527 MWT
FIGURE 6.3-26
REVISION 5, JANUARY 2003



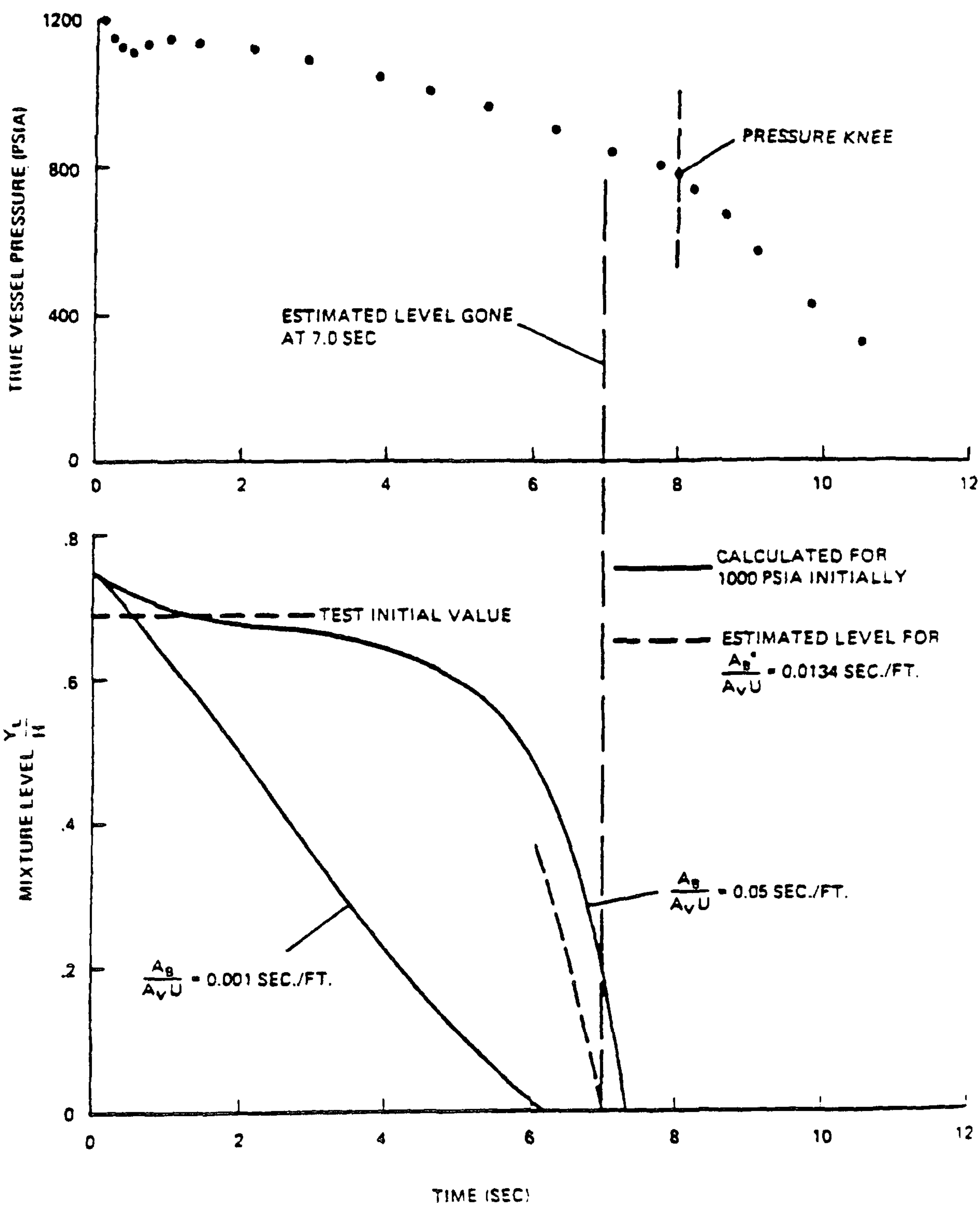
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
REVERSE FLOW RESISTANCES OF JET PUMPS AT 2527 MWT
FIGURE 6.3-27 REVISION 5, JANUARY 2003



HISTORICAL
This figure contains historical information only.

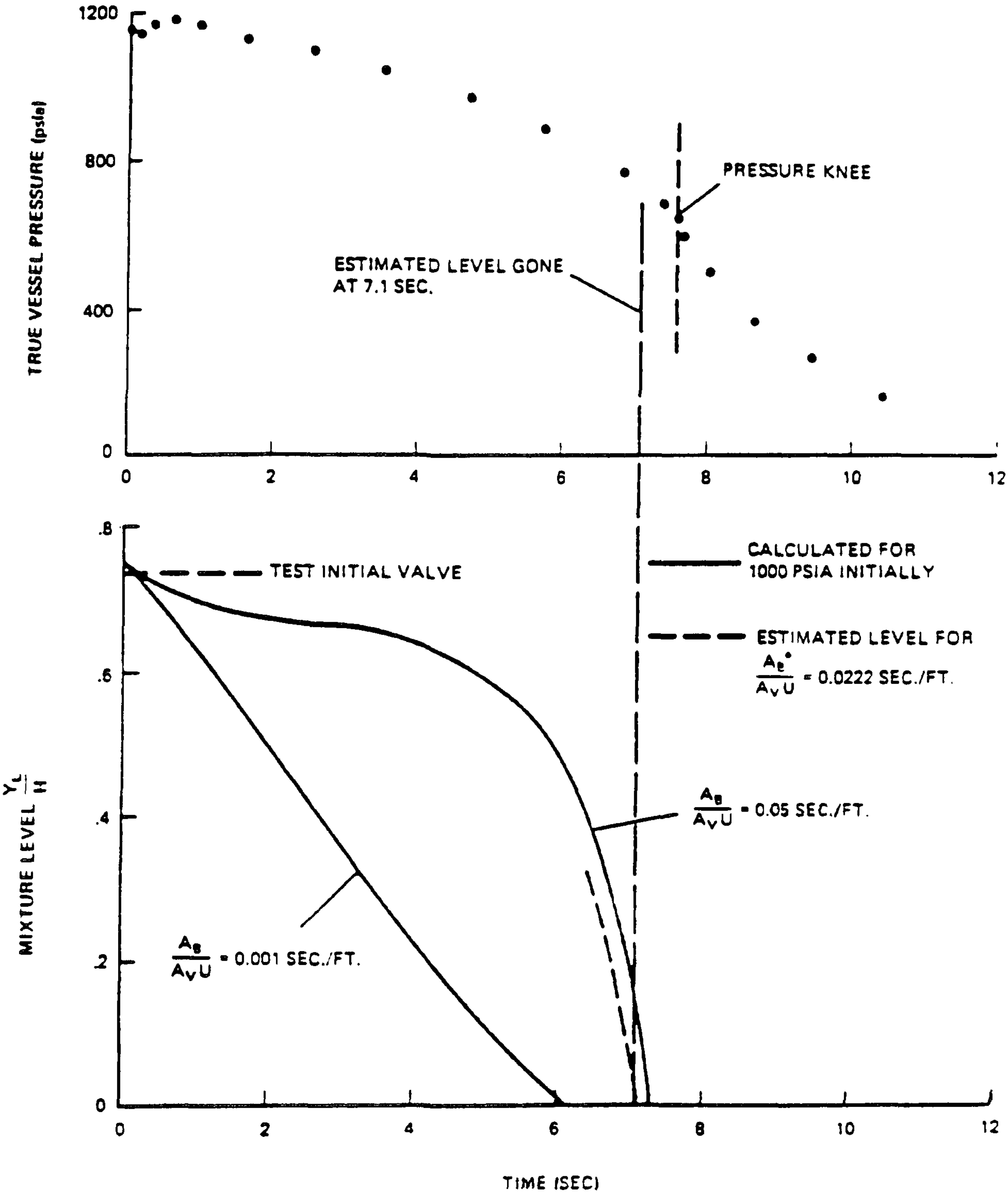
DRESDEN STATION UNITS 2 & 3
BLOWDOWN FROM A BOTTOM LOCATION AT 2527 MWt
FIGURE 6.3-28



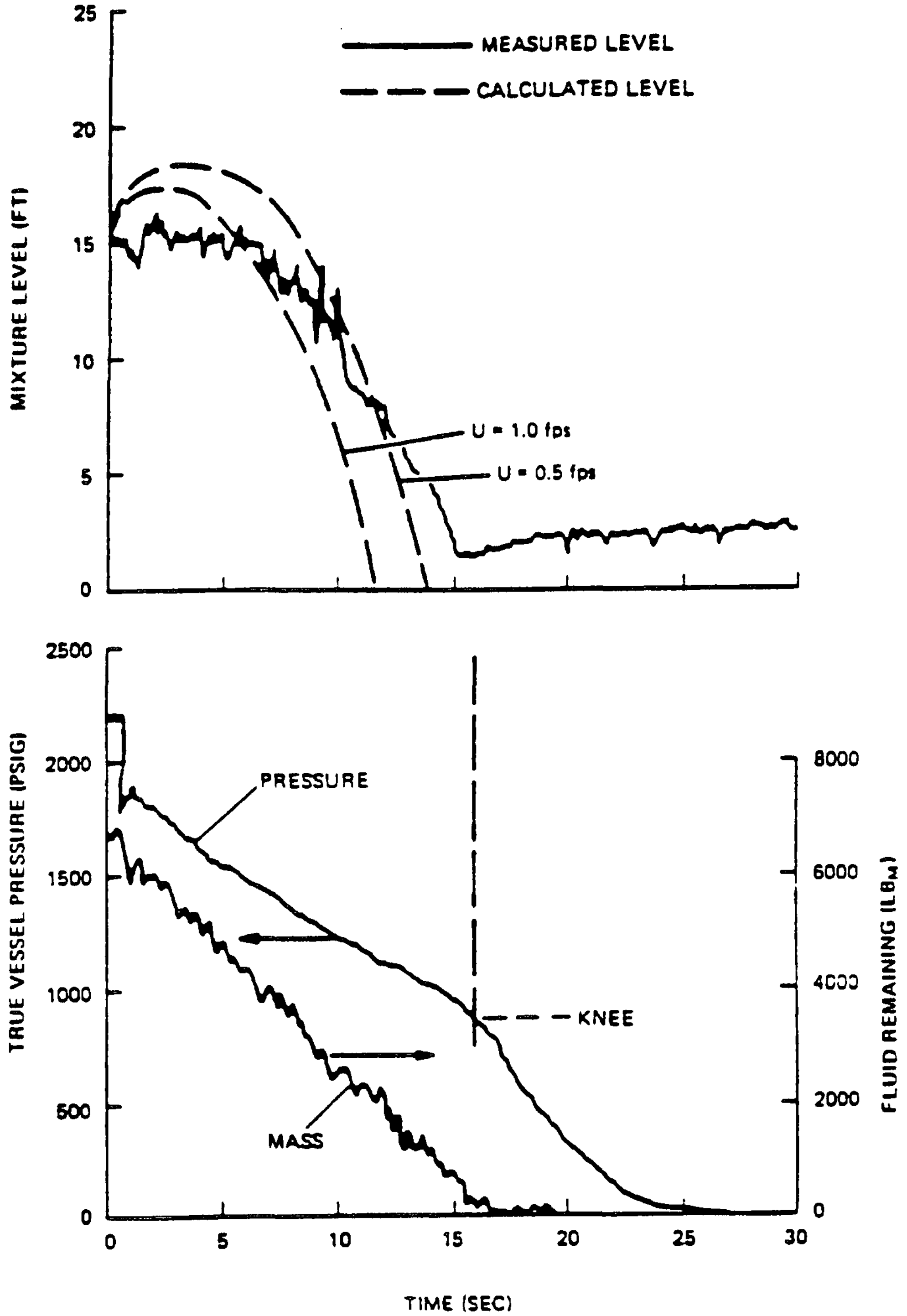
DRESDEN STATION
UNITS 2 & 3

VESSEL PRESSURE AND LEVEL TRACES - BODEGA 30

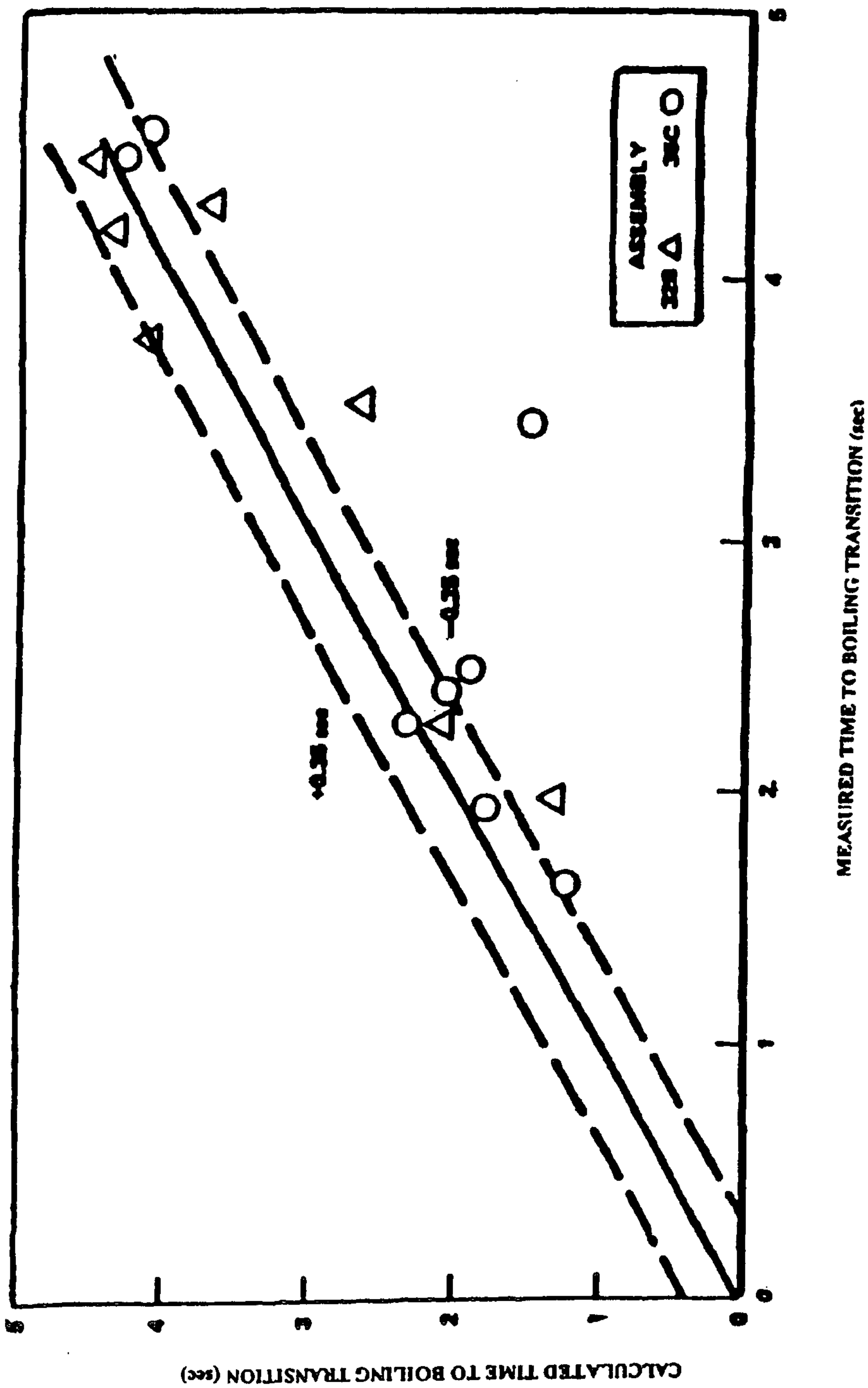
FIGURE 6.3-29



DRESDEN STATION UNITS 2 & 3
VESSEL PRESSURE AND LEVEL TRACES - HUMBOLDT 17
FIGURE 6.3-30

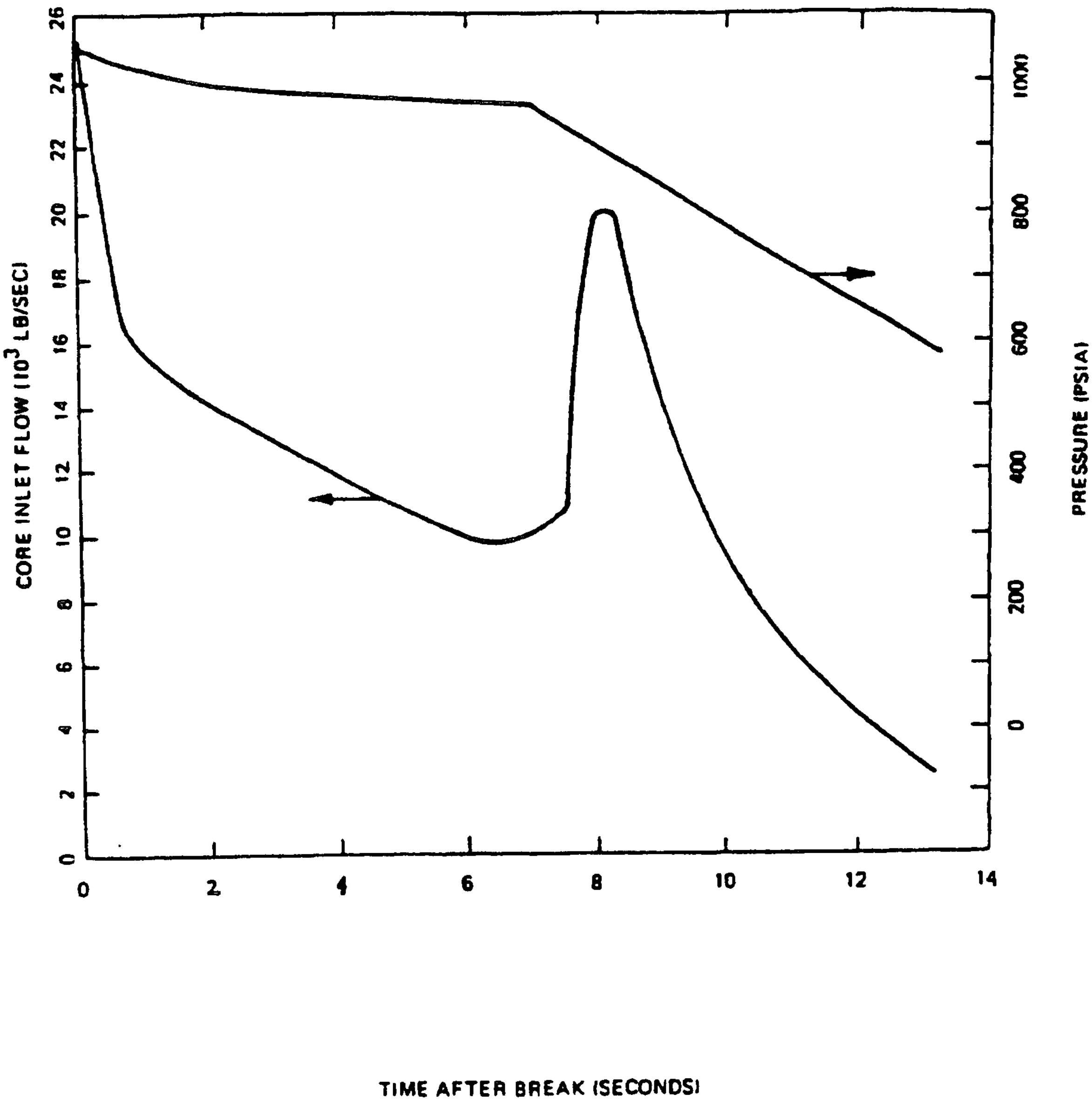


DRESDEN STATION UNITS 2 & 3
VESSEL PRESSURE AND LEVEL TRACES - CSE DATA, RUN B-15
FIGURE 6.3-31



HISTORICAL
This figure contains historical information only.

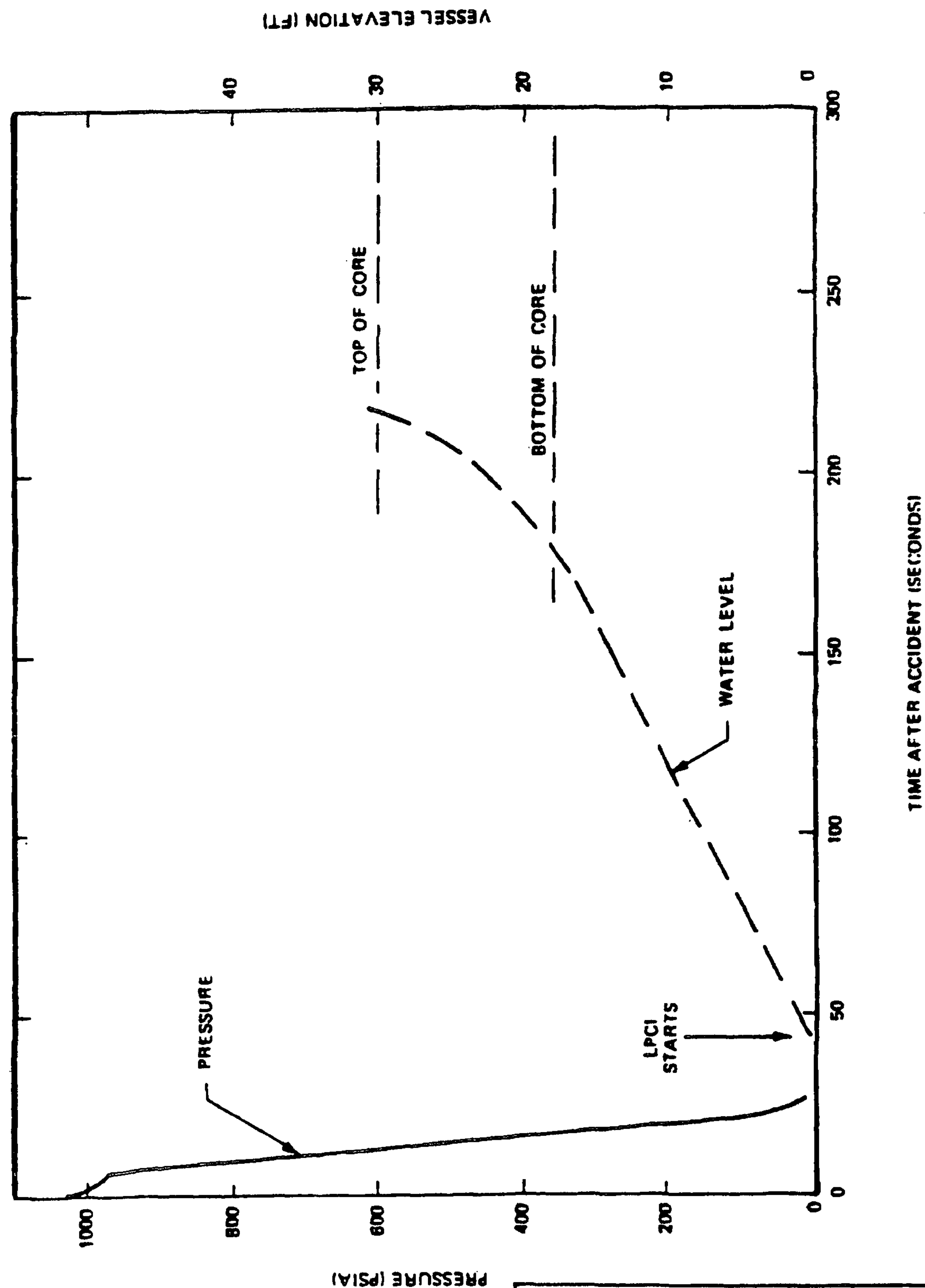
DRESDEN STATION UNITS 2 & 3
CALCULATED TIME VS. MEASURED TIME TO INITIAL BOILING TRANSITION AT 2527 MWT
FIGURE 6.3-32
REVISION 5, JANUARY 2003



HISTORICAL

This figure contains historical information only.

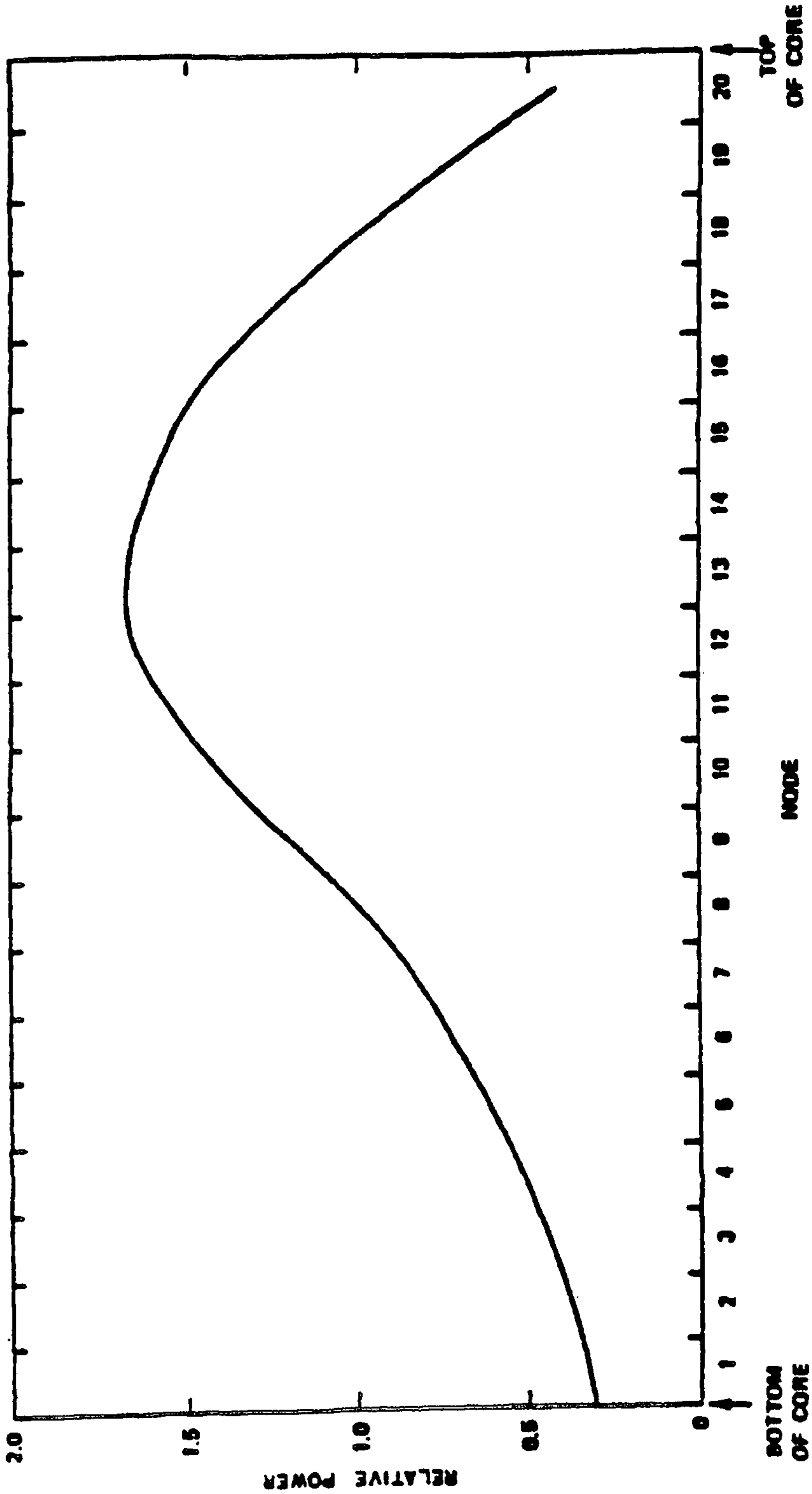
DRESDEN STATION UNITS 2 & 3
SHORT TERM CORE INLET FLOW AND PRESSURE TRANSIENT AT 2527 MWT
FIGURE 6.3-60 REVISION 5, JANUARY 2003



HISTORICAL

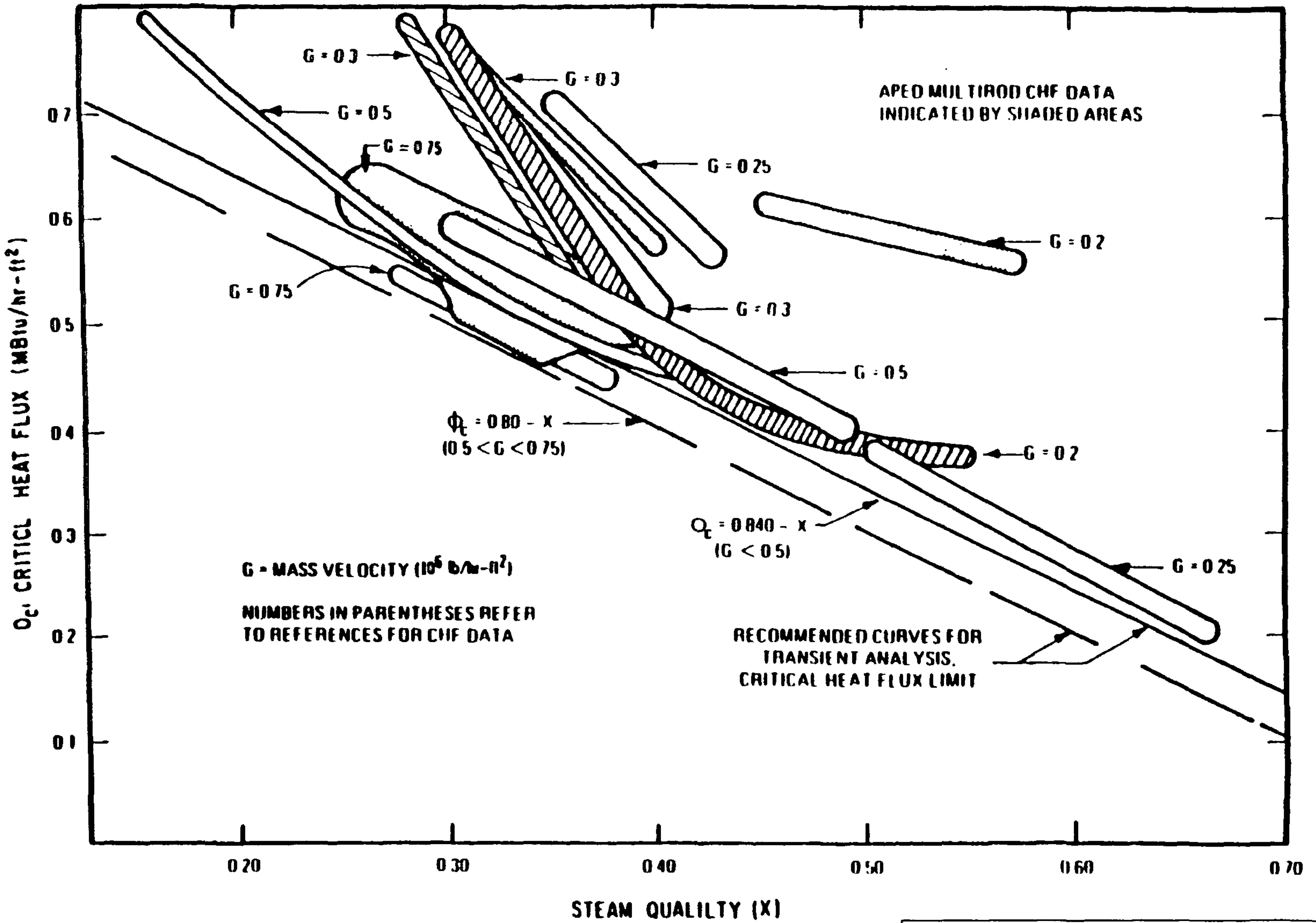
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE RESPONSE TO LPCI ALONE AT 2527 MWT
FIGURE 6.3-61 REVISION 5, JANUARY 2003

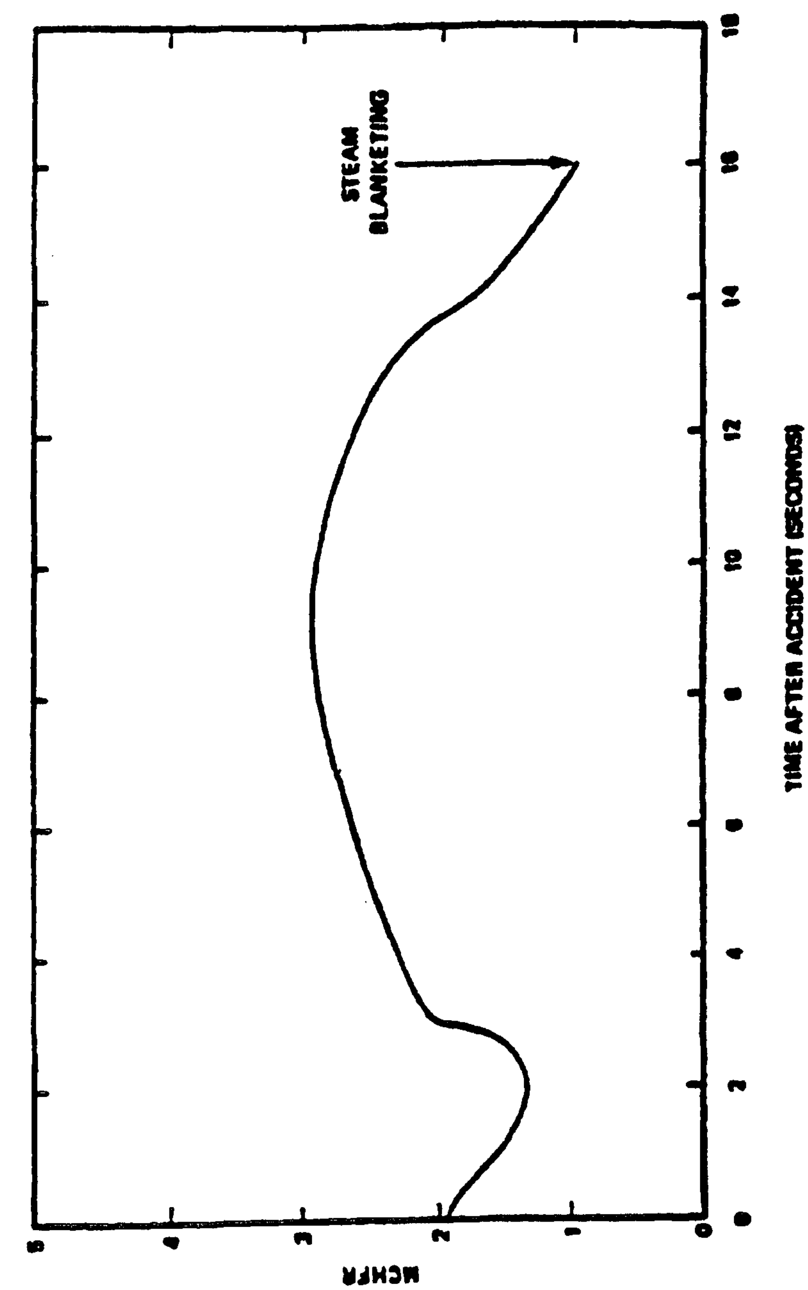


HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE AXIAL POWER DISTRIBUTION AT 2527 MWT
FIGURE 6.3-62 REVISION 5, JANUARY 2003

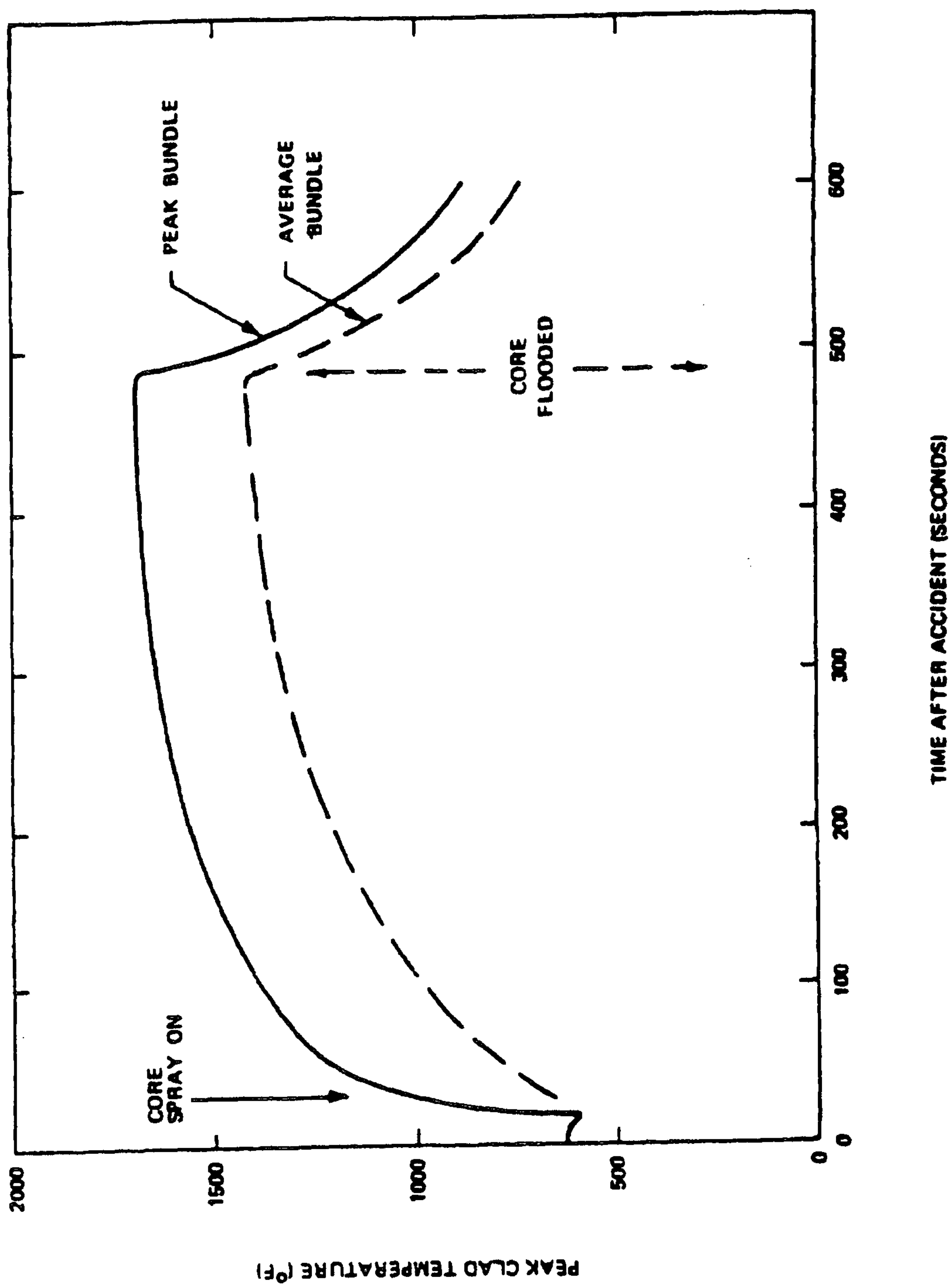


DRESDEN STATION UNITS 2 & 3
APED MULTIROD CHF DATA AT 1000 PSIA
FIGURE 6.3-63



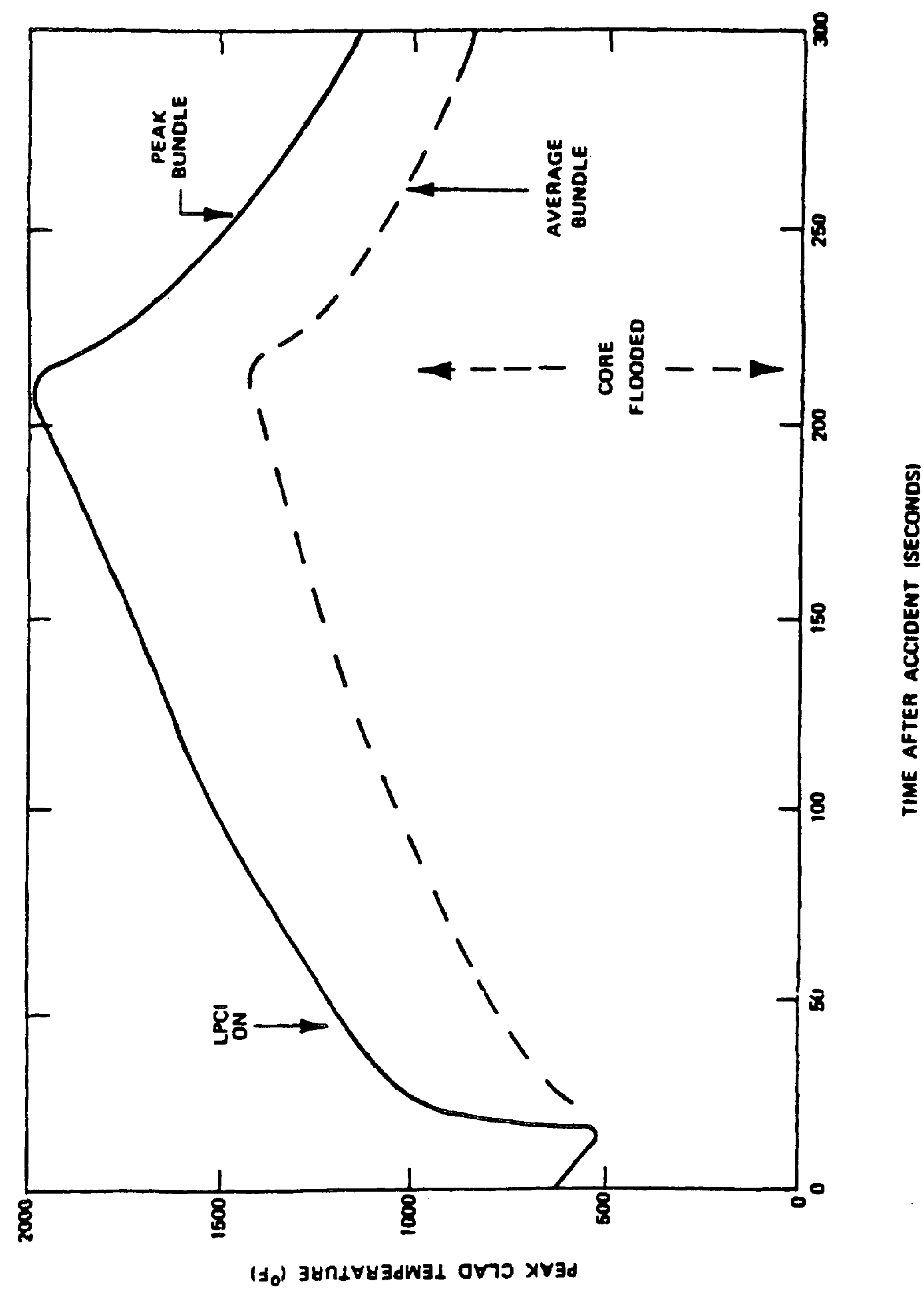
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
MCHFR TRANSIENT FOR RECIRCULATION LINE BREAK AT 2527 MWT
FIGURE 6.3-64 REVISION 5, JANUARY 2003



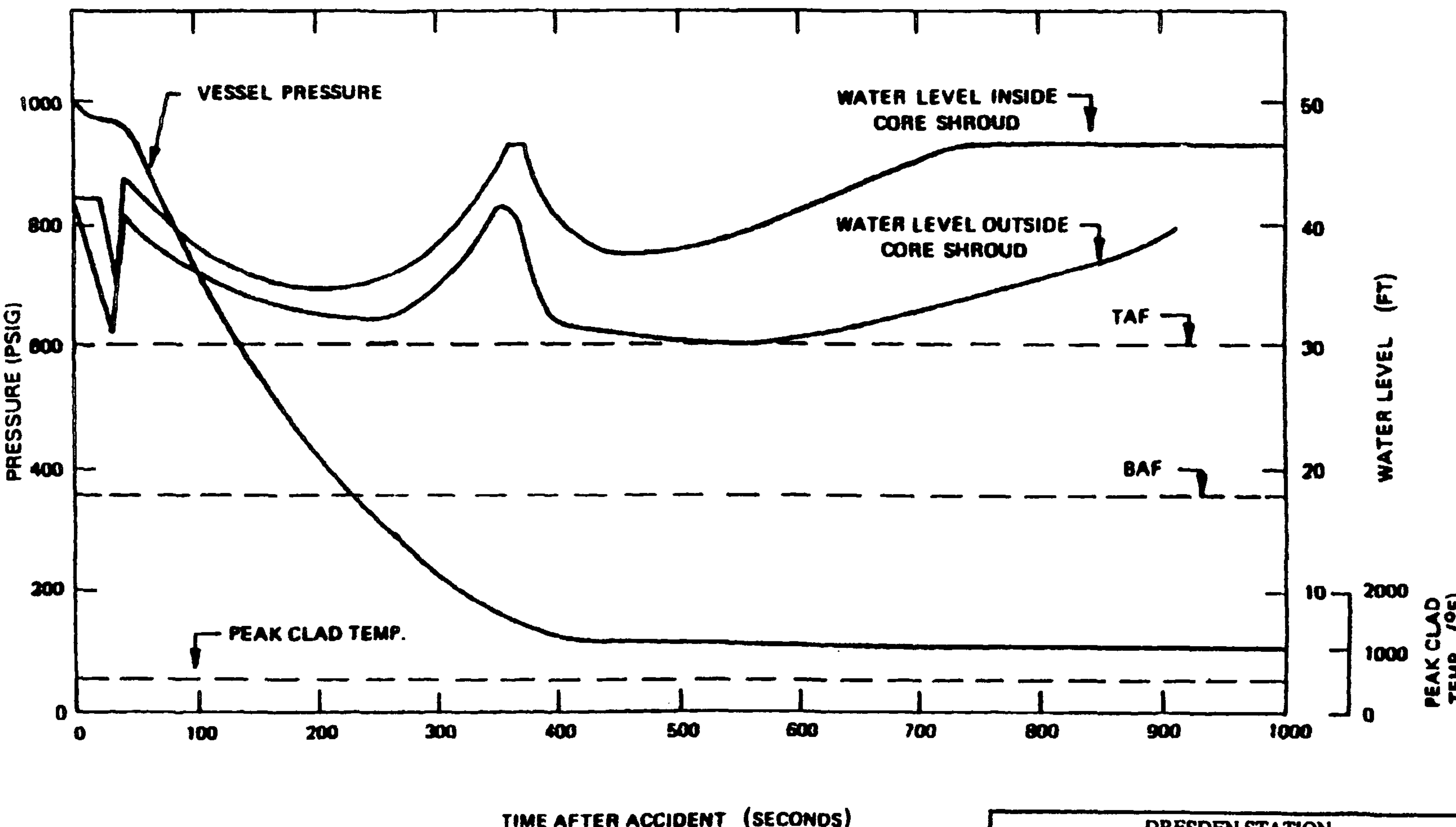
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
PEAK CLAD TEMPERATURE WITH ONE CORE SPRAY SUBSYSTEM AT 2527 MWT
FIGURE 6.3-65 REVISION 5, JANUARY 2003



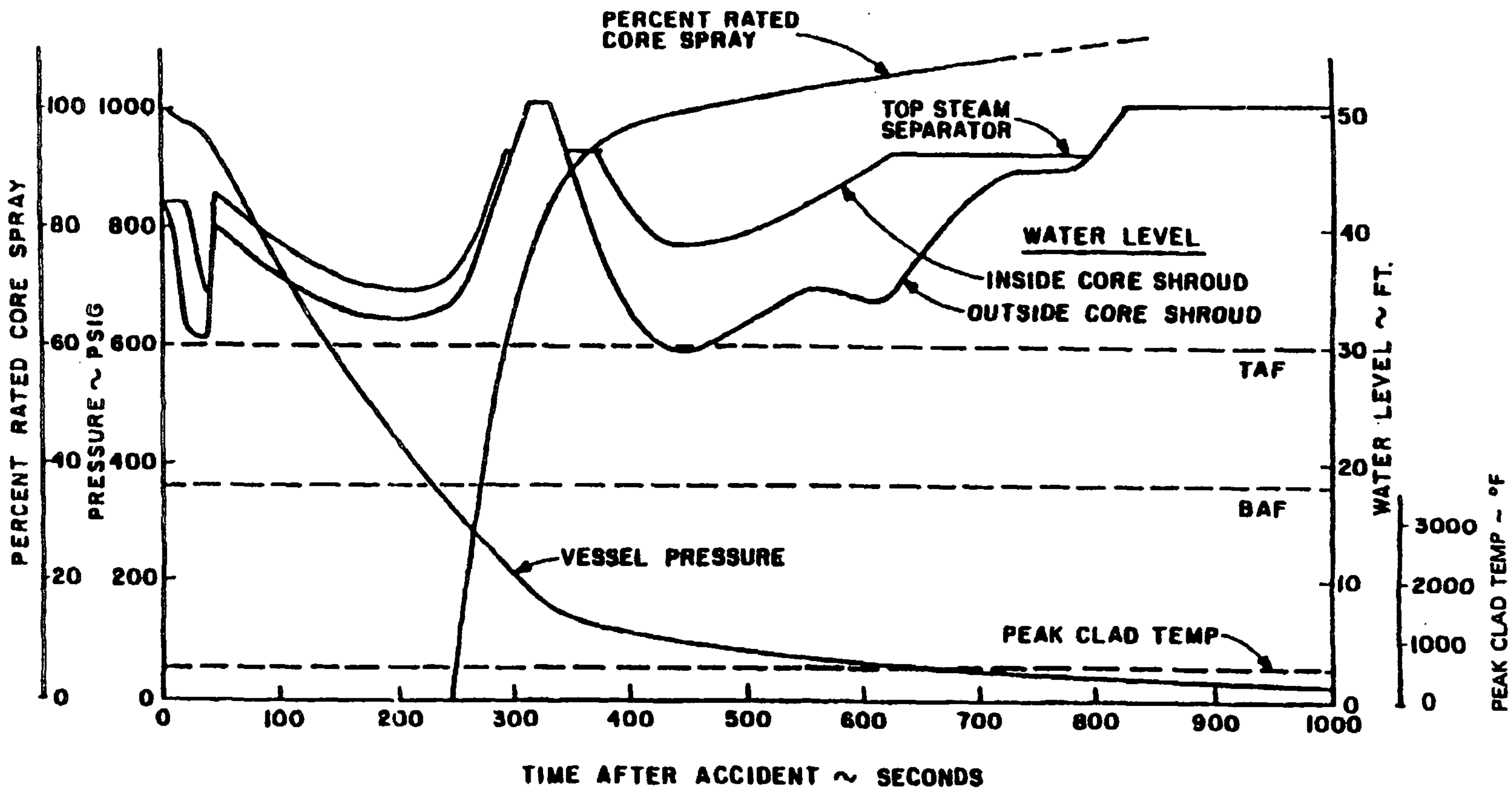
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
PEAK CLAD TEMPERATURE WITH THREE LPCI PUMPS AT 2527 MWT
FIGURE 6.3-66 REVISION 5, JANUARY 2003



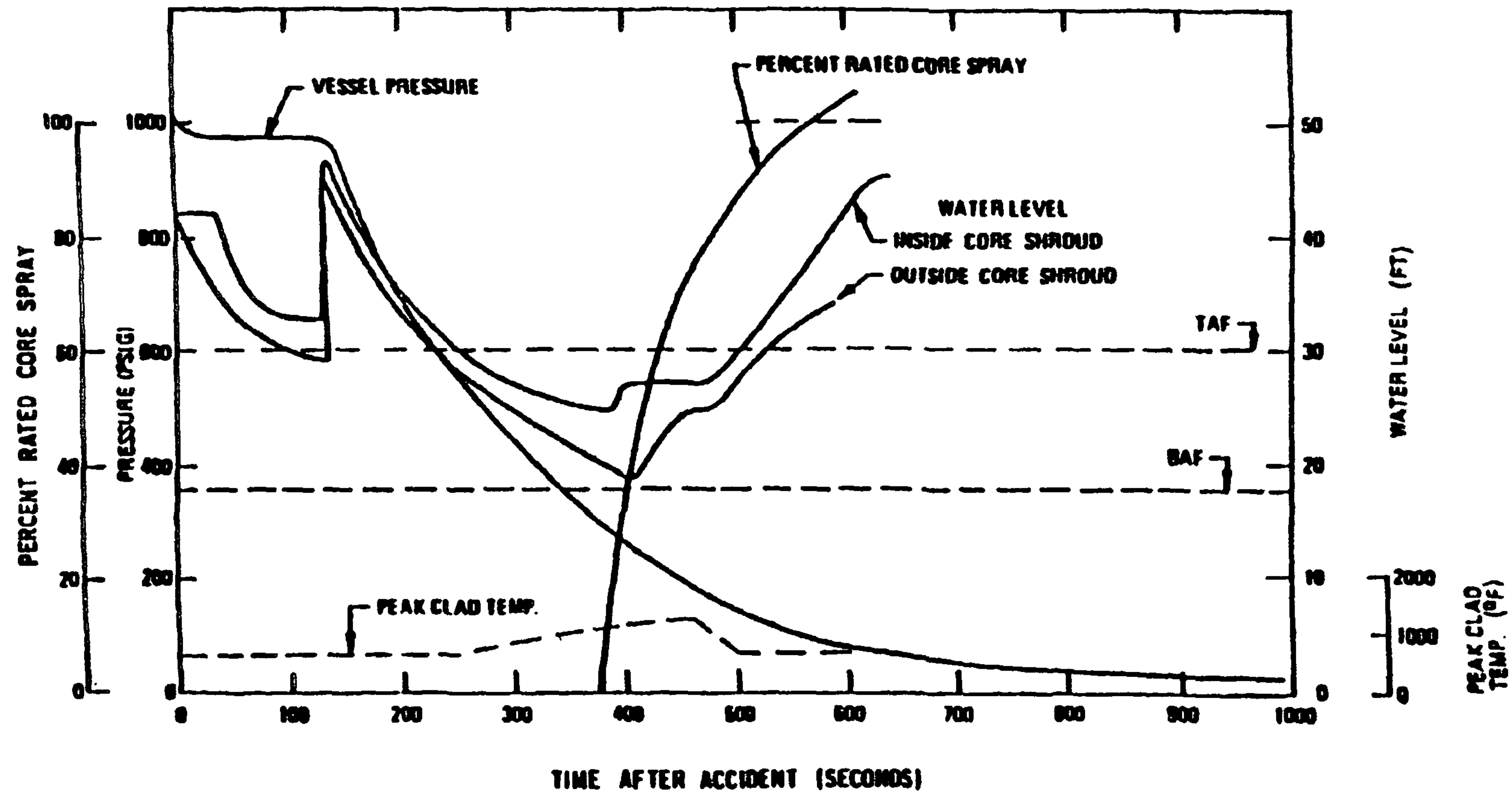
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE RESPONSE TO HPCI – LPCI (0.2 FT.^{2} BREAK AREA) AT 2527 MWT
FIGURE 6.3-67 REVISION 5, JANUARY 2003



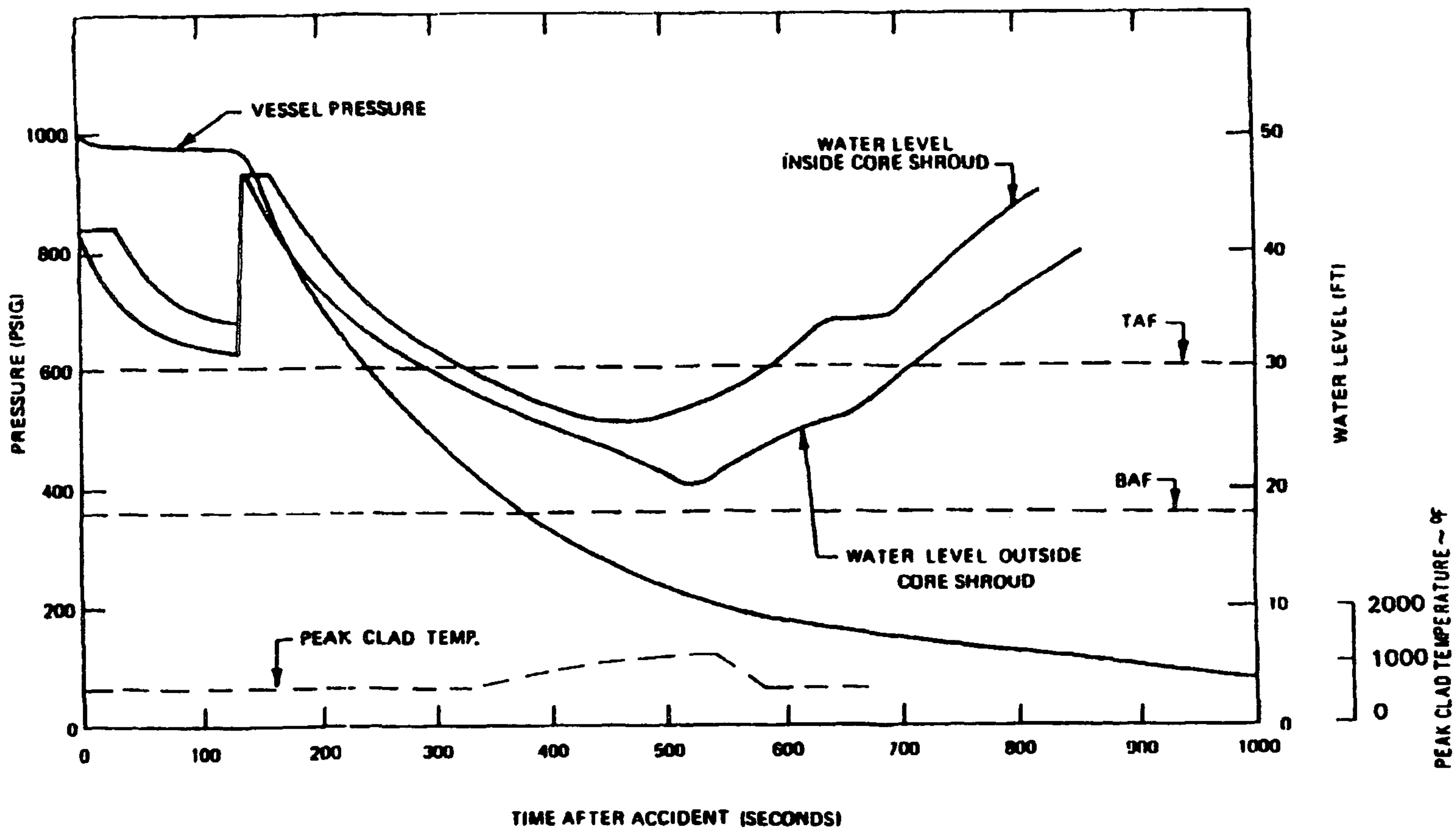
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE SPRAY – HPCI SYSTEM PERFORMANCE (0.2 FT.^{2} BREAK AREA) AT 2527 MWT
FIGURE 6.3-68 REVISION 5, JANUARY 2003



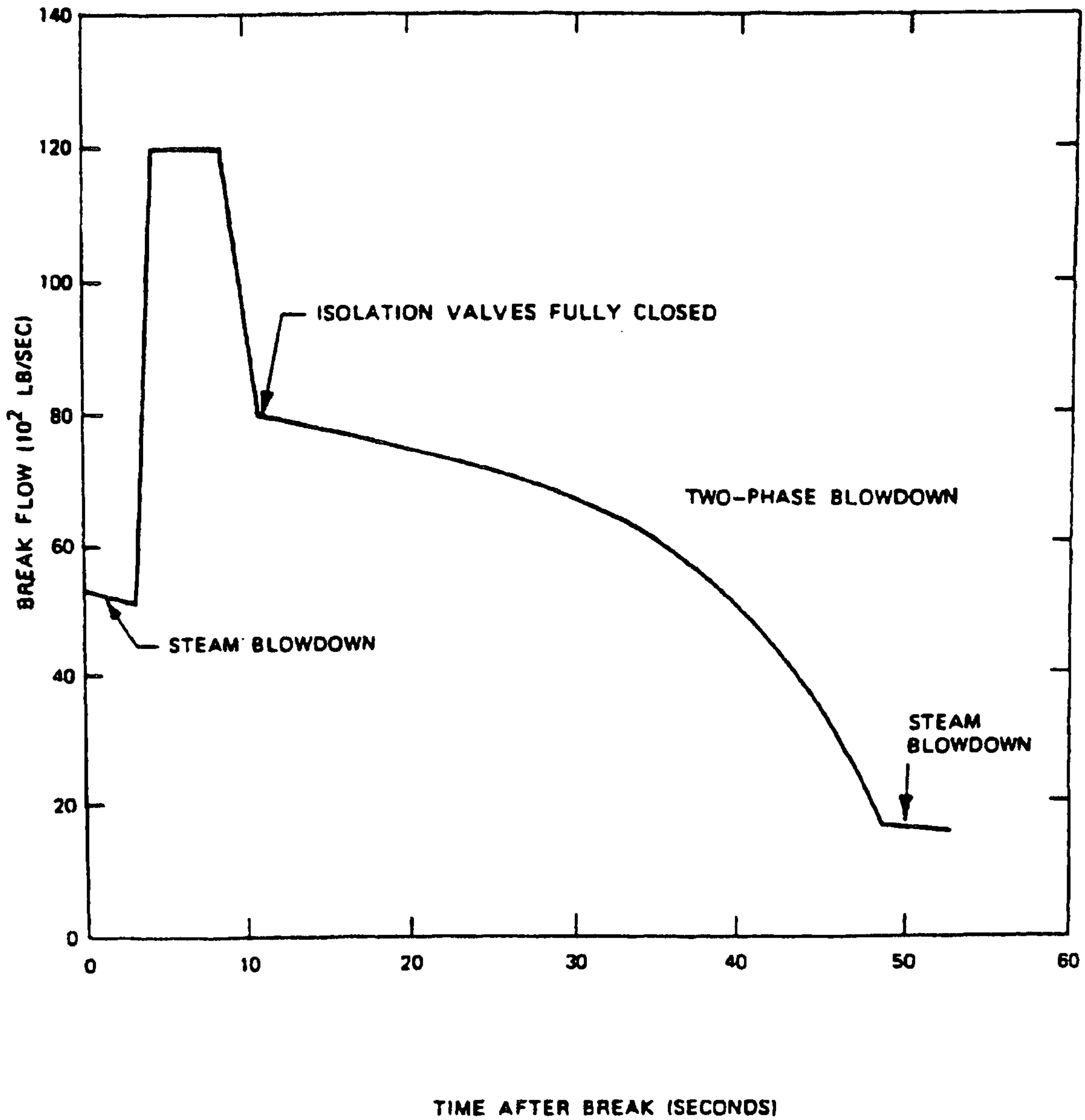
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE RESPONSE TO ADS – CORE SPRAY (0.05 FT.^{2} BREAK AREA) AT 2527 MWT
FIGURE 6.3-69 REVISION 5, JANUARY 2003



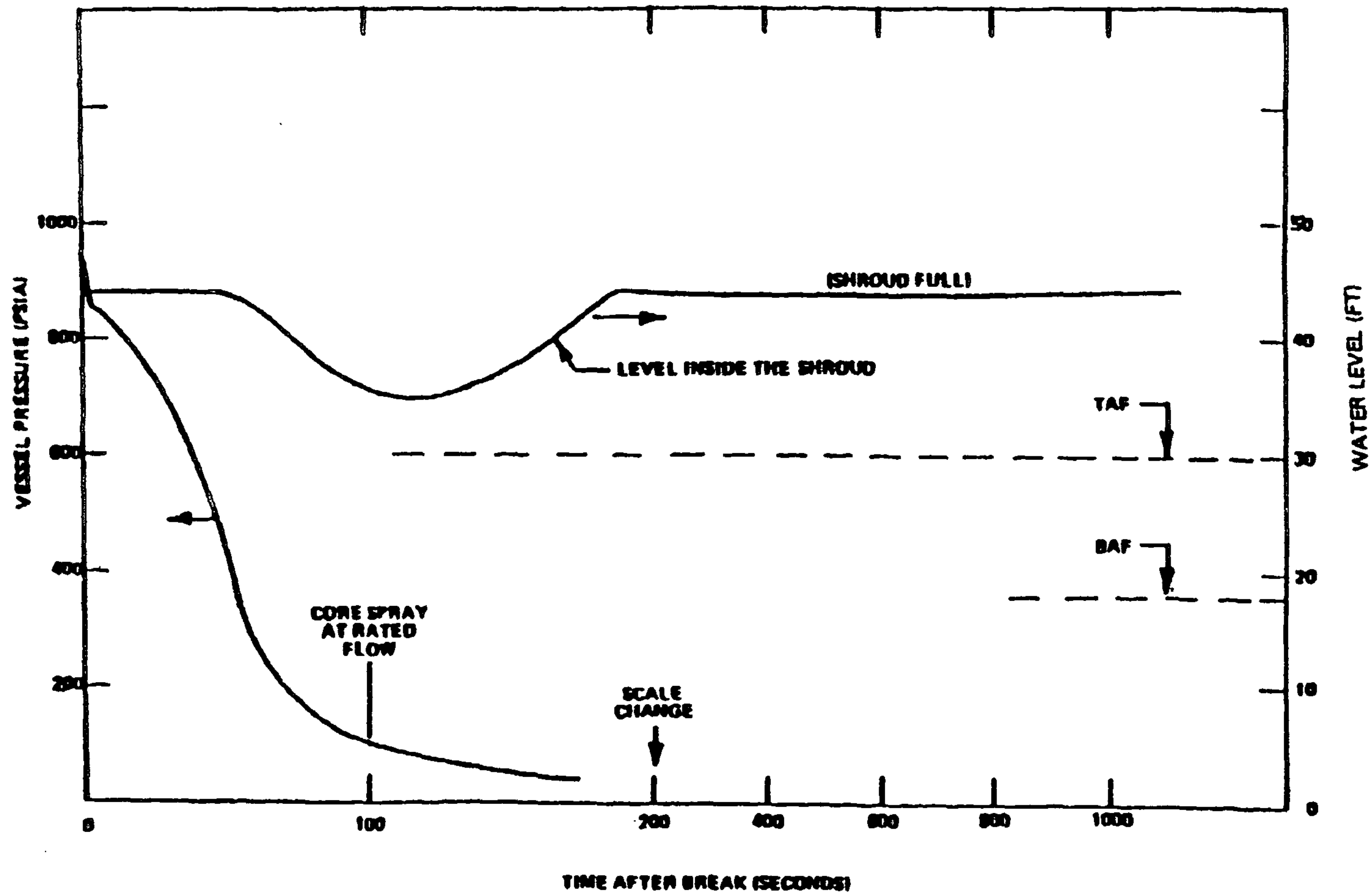
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE RESPONSE TO ADS – LPCI (0.025 FT.² BREAK AREA) AT 2527 MWT
FIGURE 6.3-70 REVISION 5, JANUARY 2003



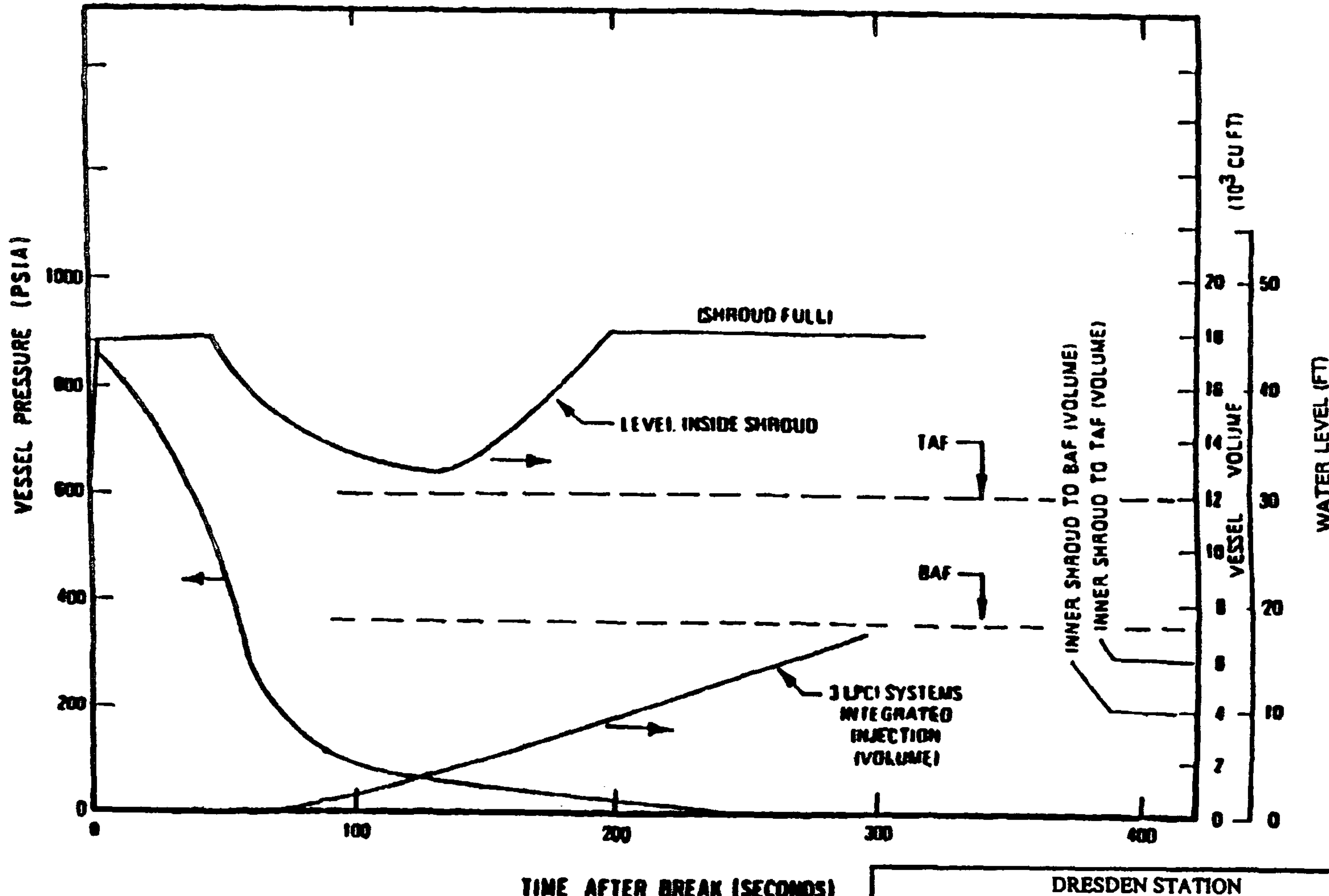
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
FLOW RATE FOLLOWING STEAM LINE BREAK INSIDE DRYWELL AT 2527 MWT
FIGURE 6.3-71 REVISION 5, JANUARY 2003



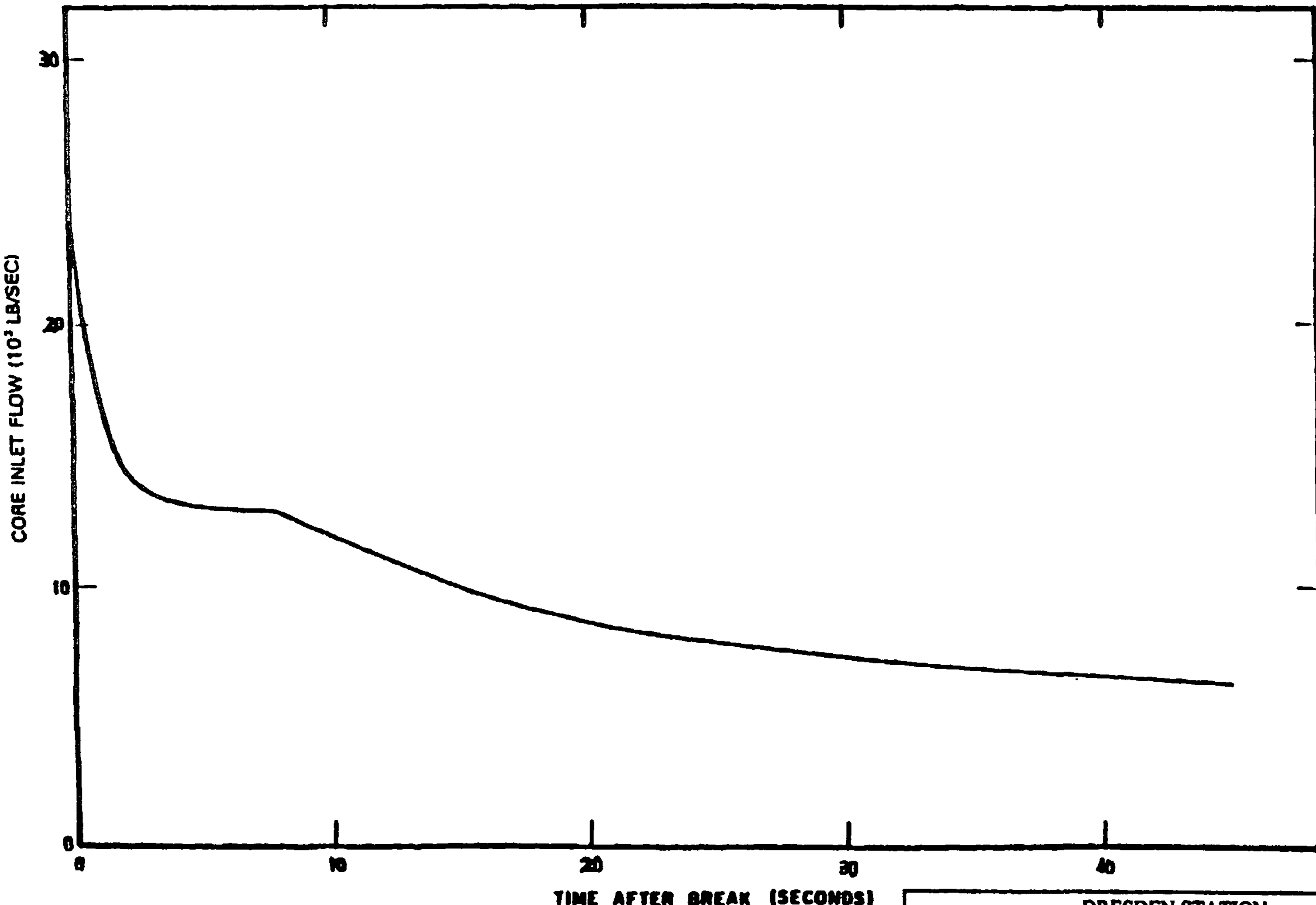
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE RESPONSE TO STEAM LINE BREAK INSIDE DRYWELL – CORE SPRAY AT 2527 MWT
FIGURE 6.3-72 REVISION 5, JANUARY 2003



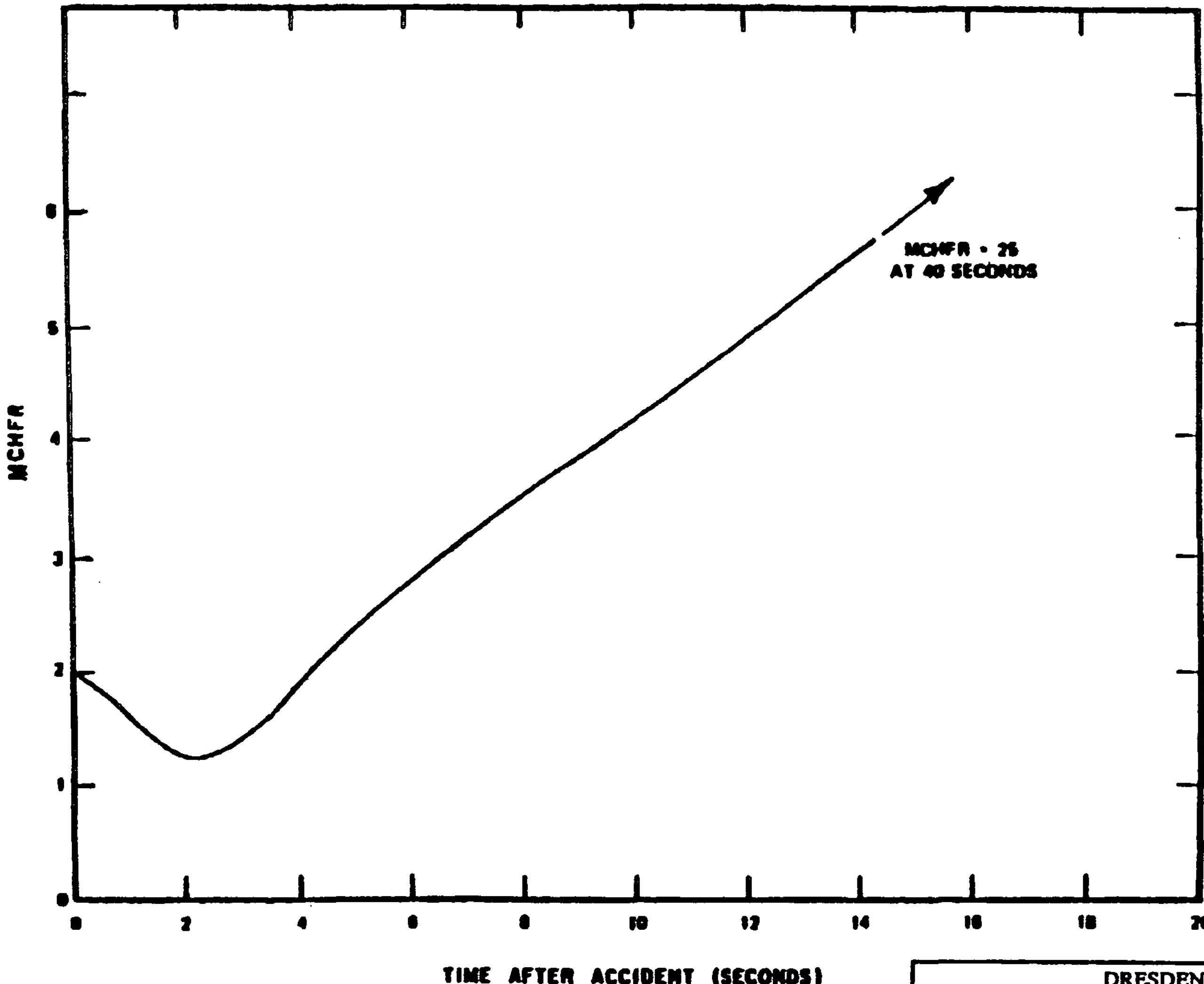
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE RESPONSE TO STEAM LINE BREAK INSIDE DRYWELL – LPCI AT 2527 MWT
FIGURE 6.3-73 REVISION 5, JANUARY 2003



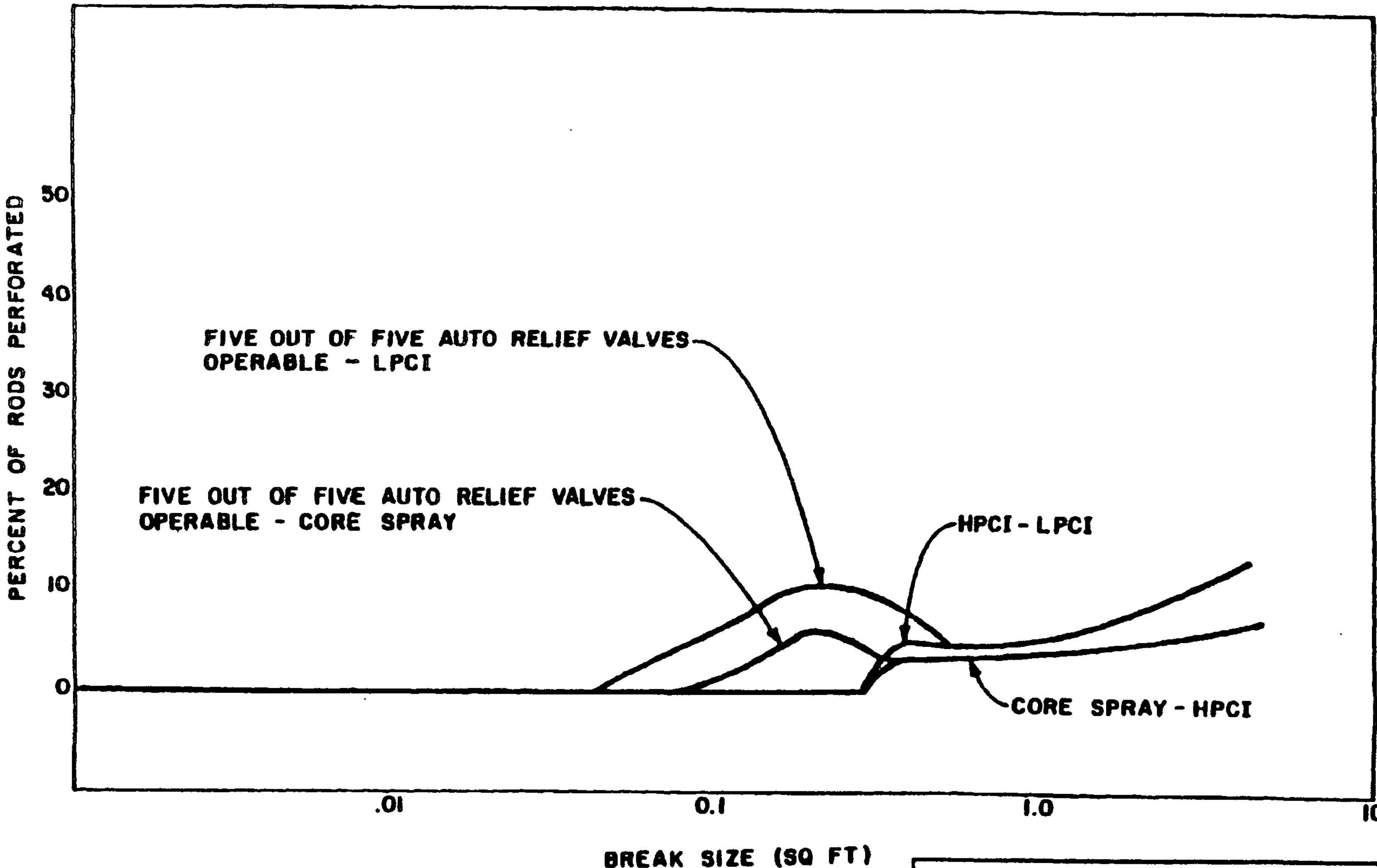
HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
CORE INLET FLOW FOLLOWING STEAM LINE BREAK INSIDE DRYWELL AT 2527 MWT
FIGURE 6.3-74 REVISION 5, JANUARY 2003



HISTORICAL
This figure contains historical information only.

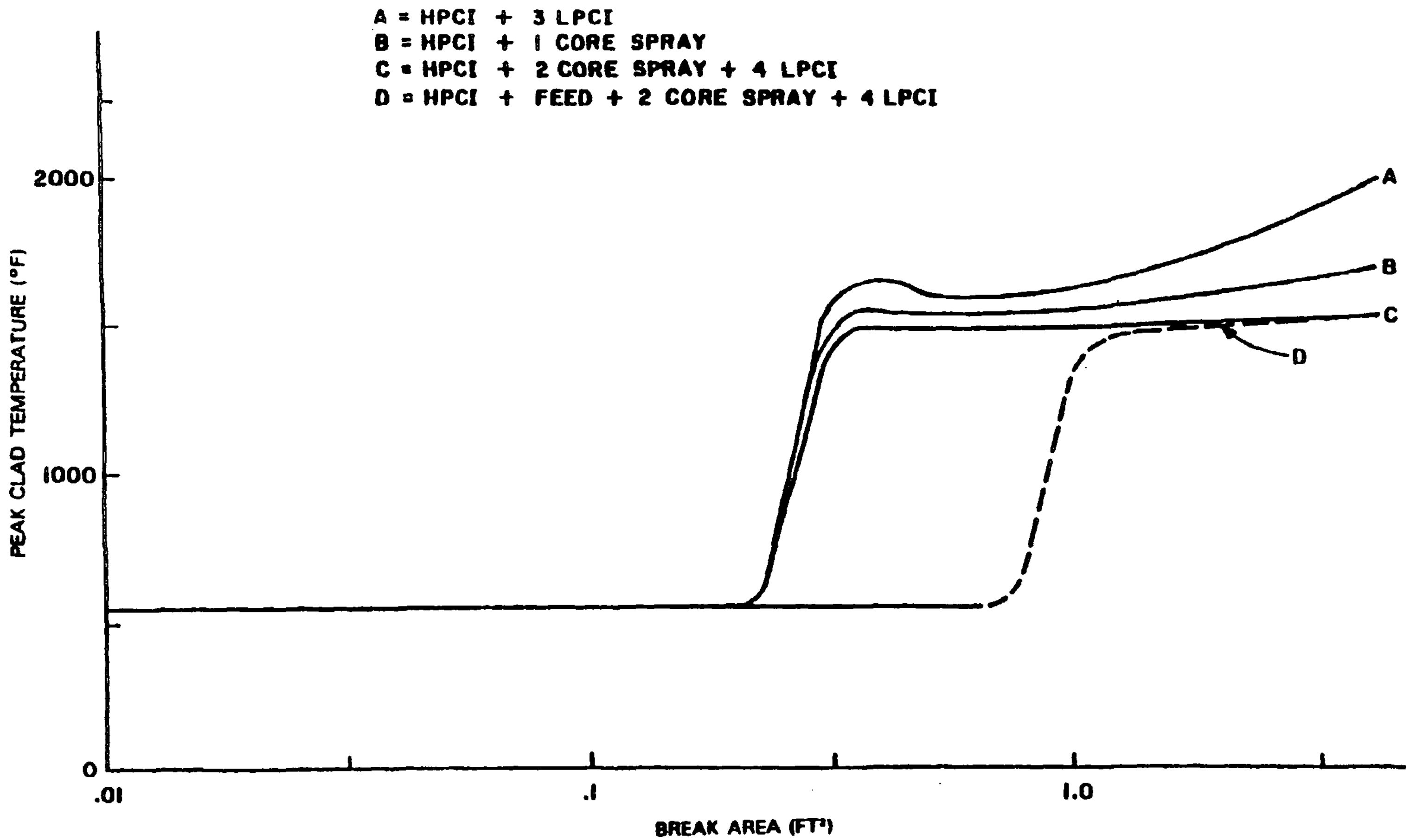
DRESDEN STATION UNITS 2 & 3
MCHFR TRANSIENT FOR STEAM LINE BREAK INSIDE DRYWELL AT 2527 MWT
FIGURE 6.3-75 REVISION 5, JANUARY 2003



HISTORICAL
This figure contains historical information only.

DRESDEN STATION UNITS 2 & 3
RODS PERFORATED VS. LIQUID BREAK SIZE AT 2527 MWT
FIGURE 6.3-76 REVISION 5, JANUARY 2003

Figures 6.3-77 and 6.3-78
Deleted



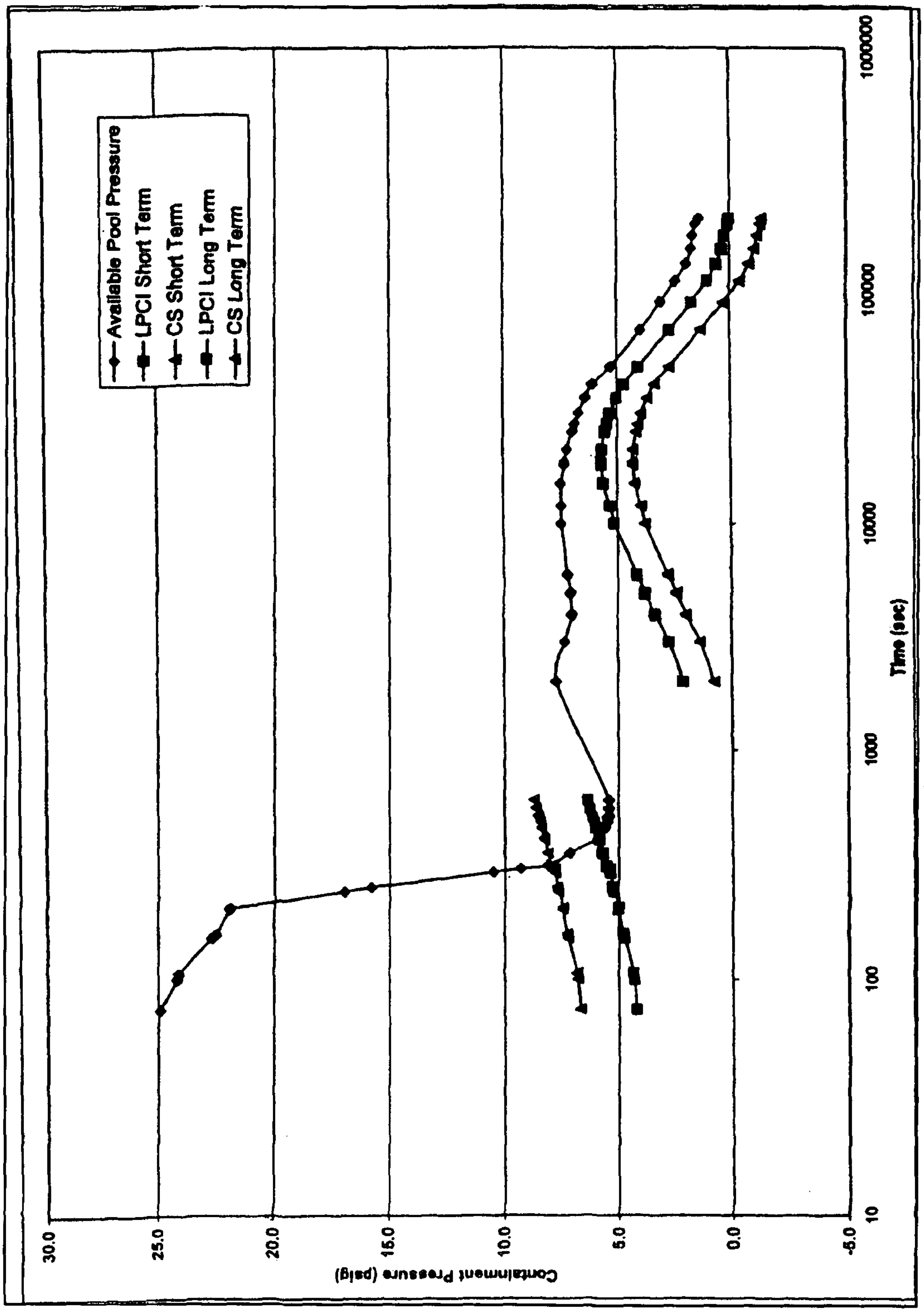
HISTORICAL
This figure contains historical information only.

DRESDEN STATION
UNITS 2 & 3

PEAK CLAD TEMPERATURE VS.
LIQUID BREAK SIZE AT 2527 MWT

FIGURE 6.3-79
REVISION 5, JANUARY 2003

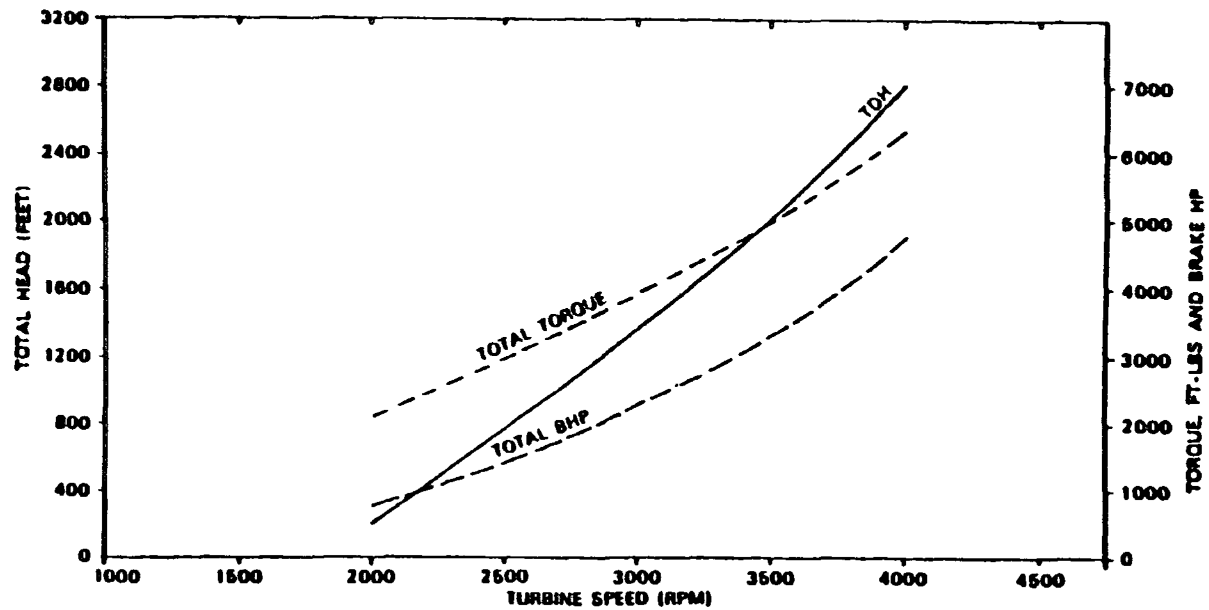
REVISION 5
JANUARY 2003



DRESDEN STATION
UNITS 2 & 3

MINIMUM CONTAINMENT PRESSURE AVAILABLE AND CONTAINMENT PRESSURE REQUIRED FOR PUMP NPSH (2957 MWt)

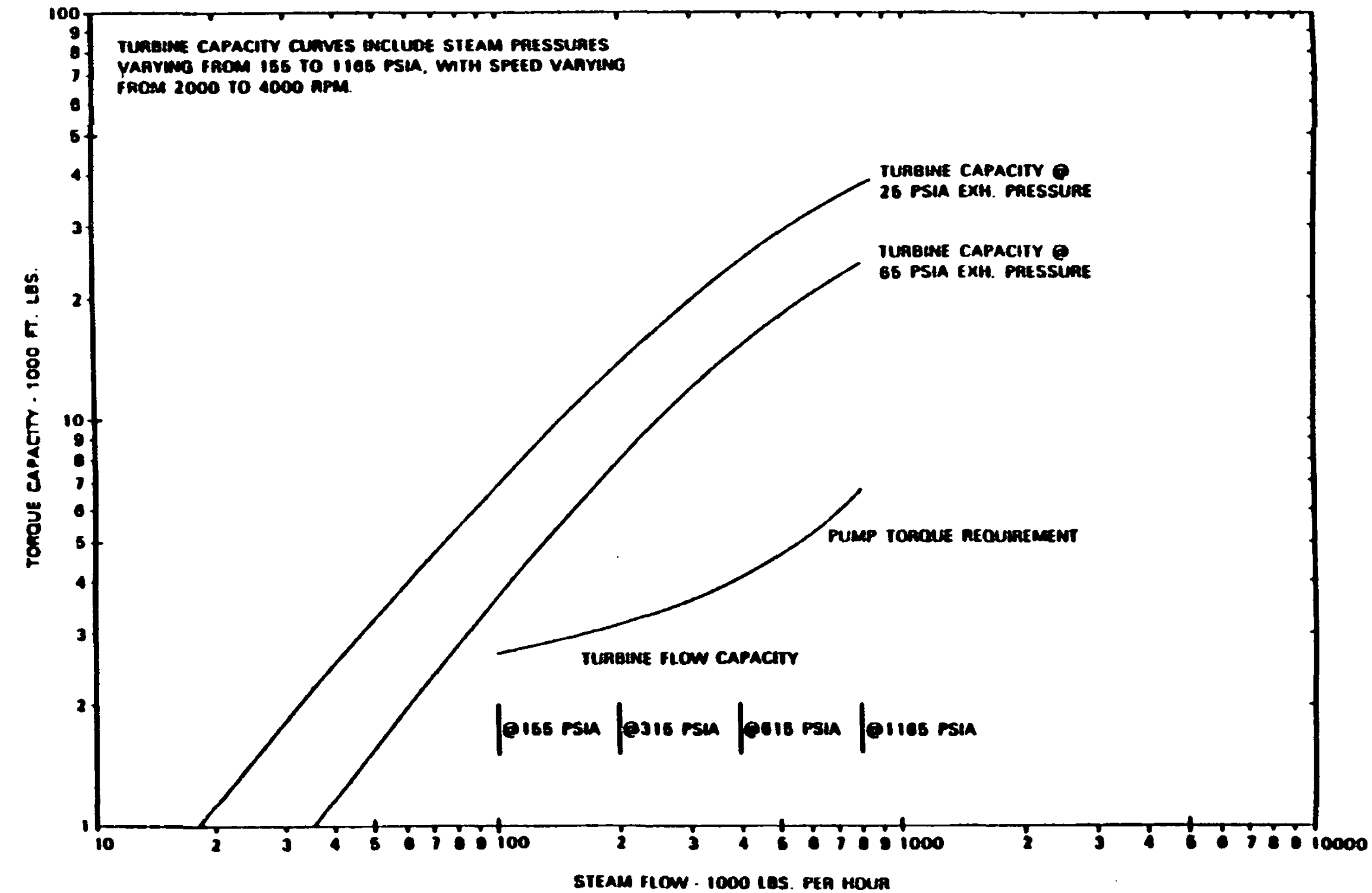
FIGURE 6.3-80



DRESDEN STATION
UNITS 2 & 3

HPCI PUMP CHARACTERISTICS

FIGURE 6.3-81

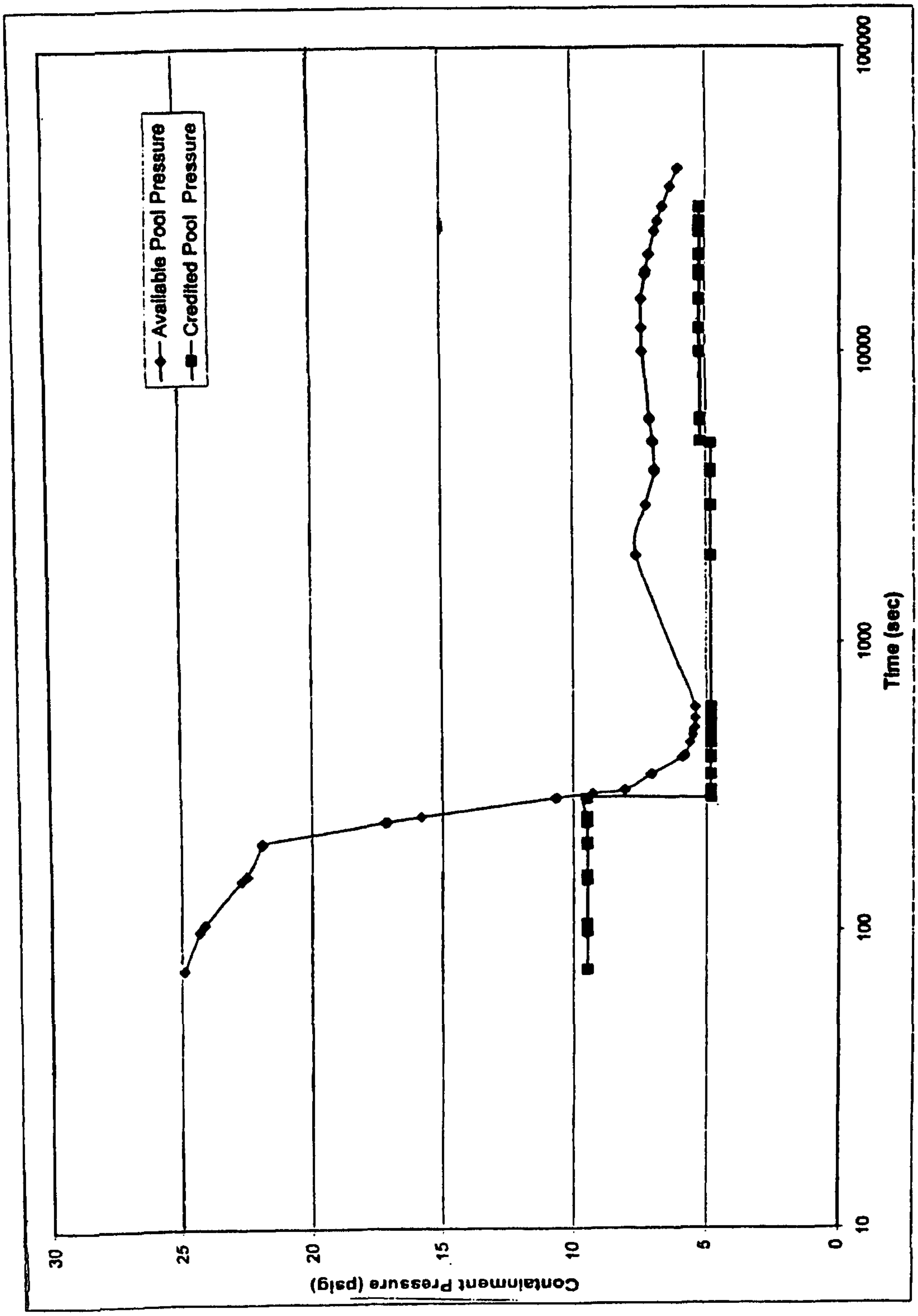


DRESDEN STATION
UNITS 2 & 3

EXAMPLE HPCI TURBINE CAPACITY CURVES

FIGURE 6.3-82

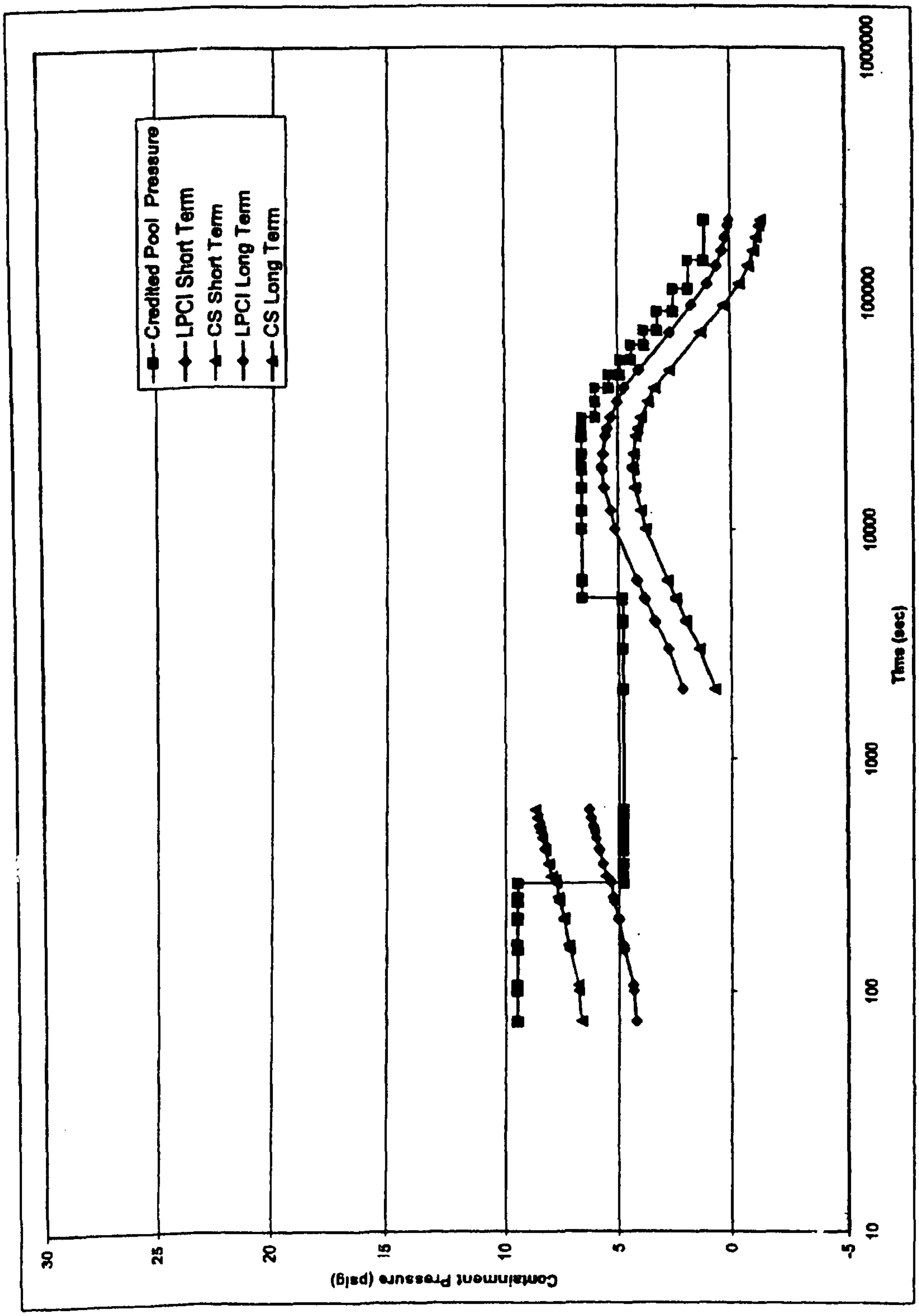
REVISION 5
JANUARY 2003



DRESDEN STATION
UNITS 2 & 3

MINIMUM CONTAINMENT PRESSURE AVAILABLE AND CREDITED CONTAINMENT PRESSURE FOR PUMP NPSH (2957 MWt)

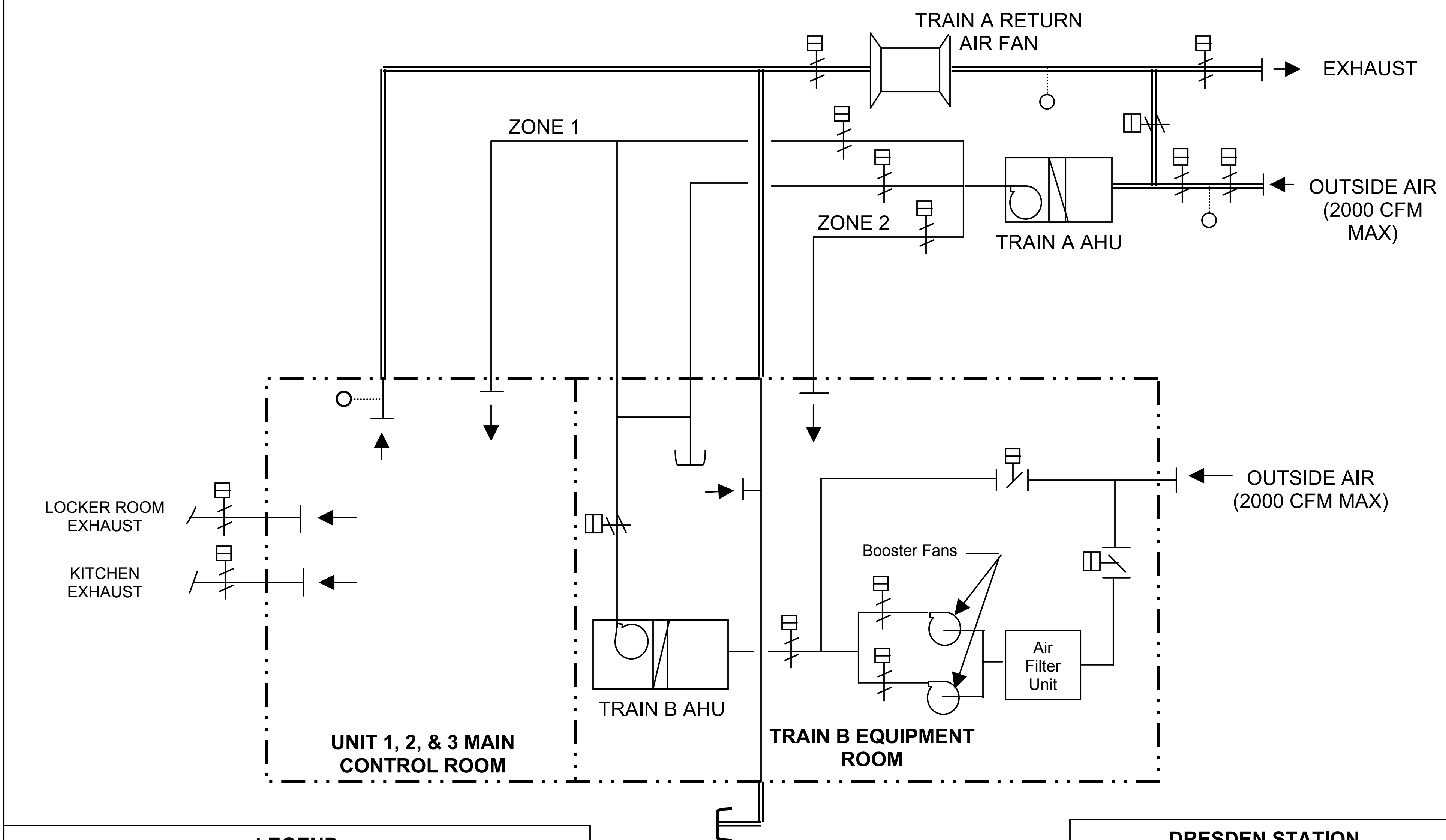
FIGURE 6.3-83



DRESDEN STATION
UNITS 2 & 3

CREDITED CONTAINMENT PRESSURE FOR PUMP NPSH (2957 MWt)

FIGURE 6.3-84



LEGEND

DUCTWORK LOCATED OUTSIDE EMERGENCY ZONE AND UNDER NEGATIVE PRESSURE

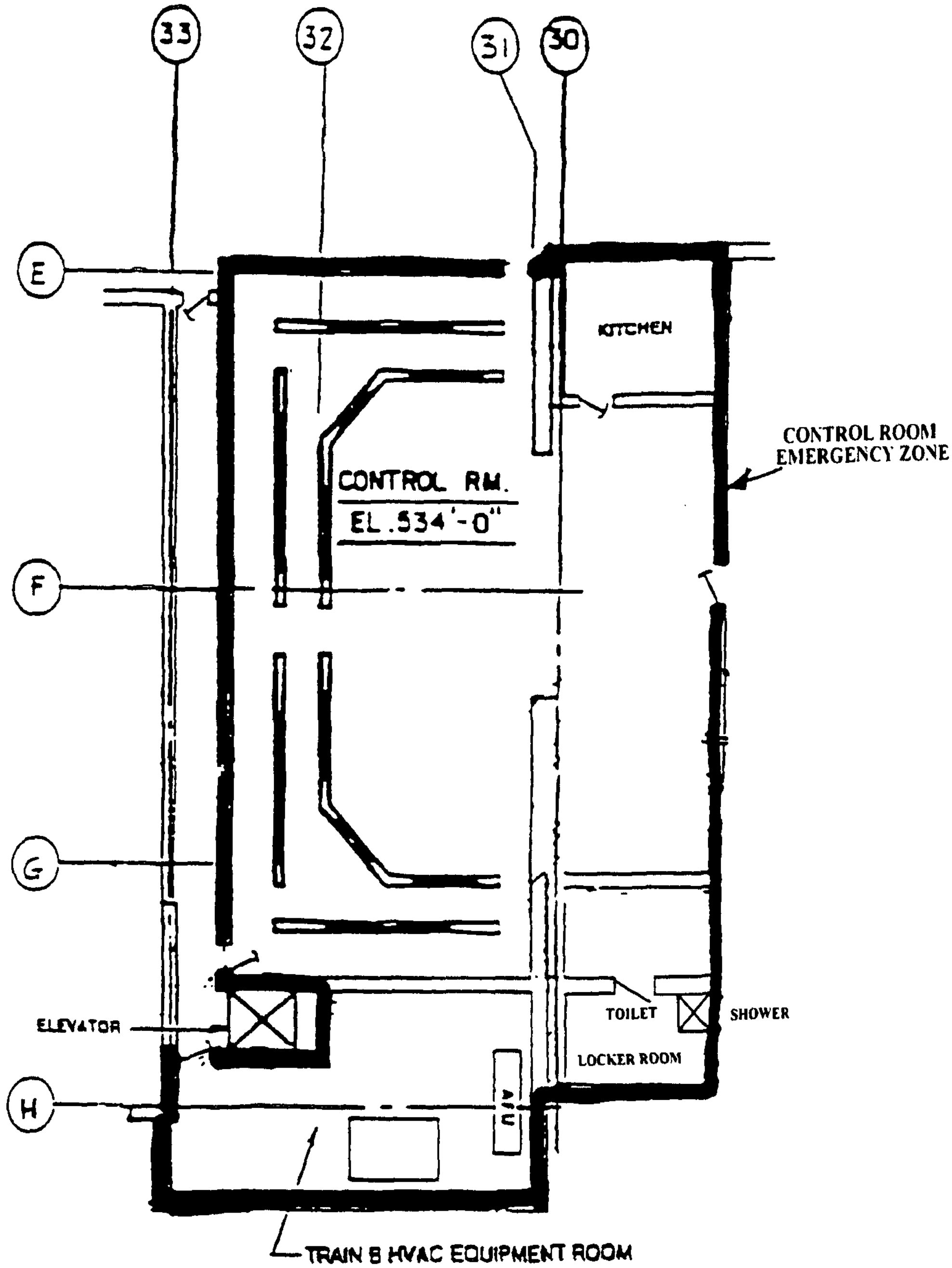
SMOKE DETECTOR

EMERGENCY ZONE BOUNDARY

DRESDEN STATION
UNITS 2 & 3

DRESDEN CONTROL ROOM
HVAC SCHEMATIC

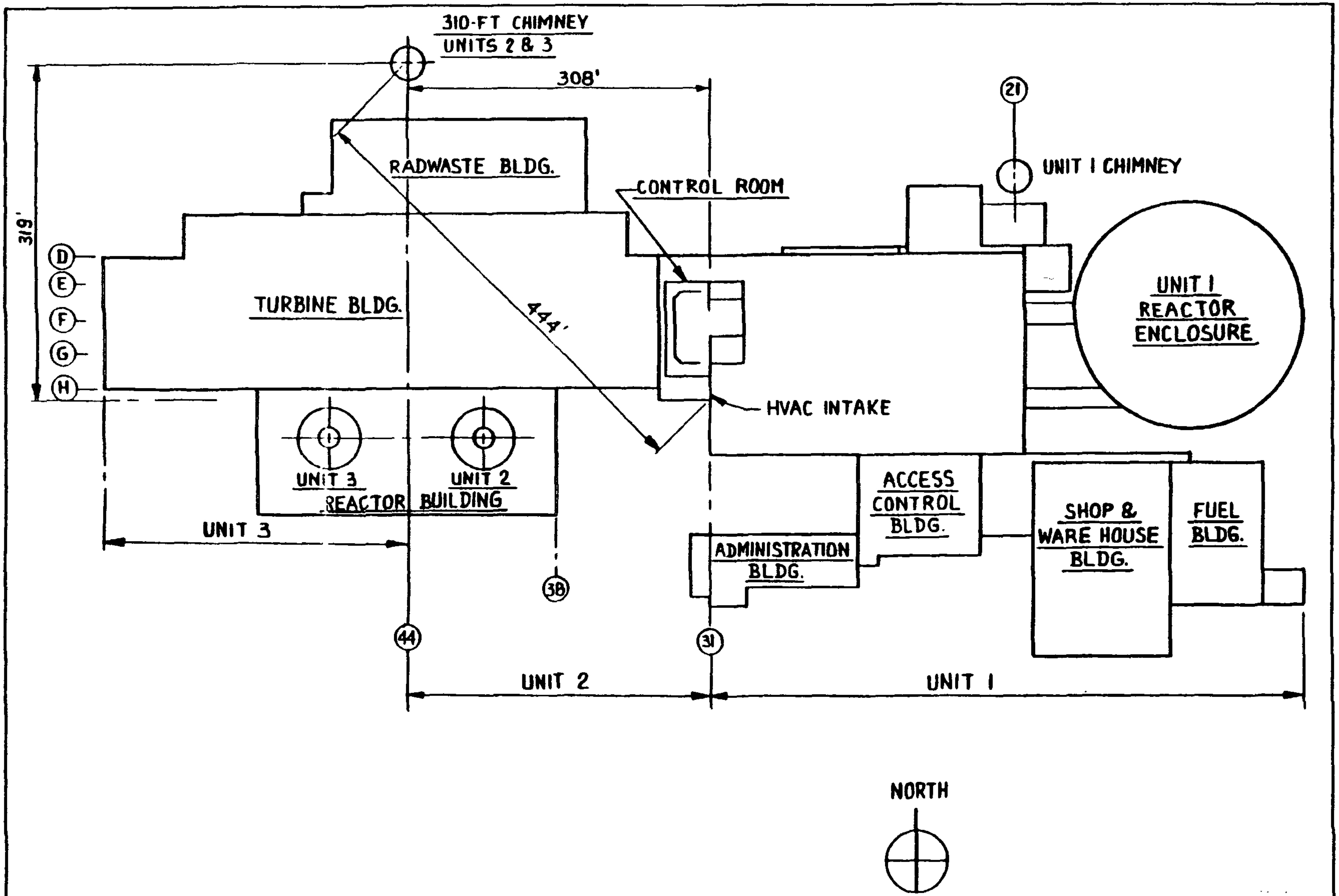
Figure 6.4-1



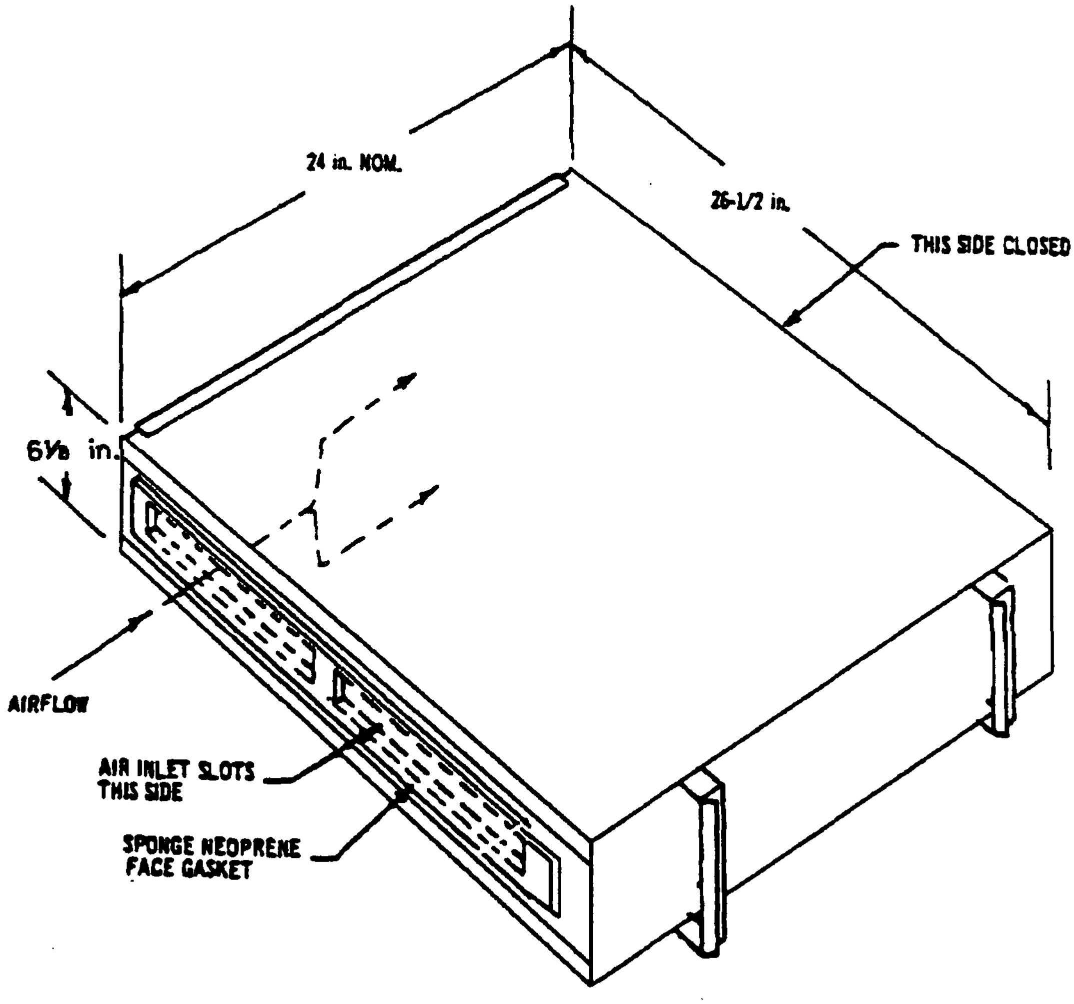
NOTE 1: TRAIN A HVAC EQUIPMENT ROOM IS DIRECTLY ABOVE THE TRAIN B HVAC EQUIPMENT ROOM AT ELEVATION 549'

UFSAR REV. 3 JUNE 1999

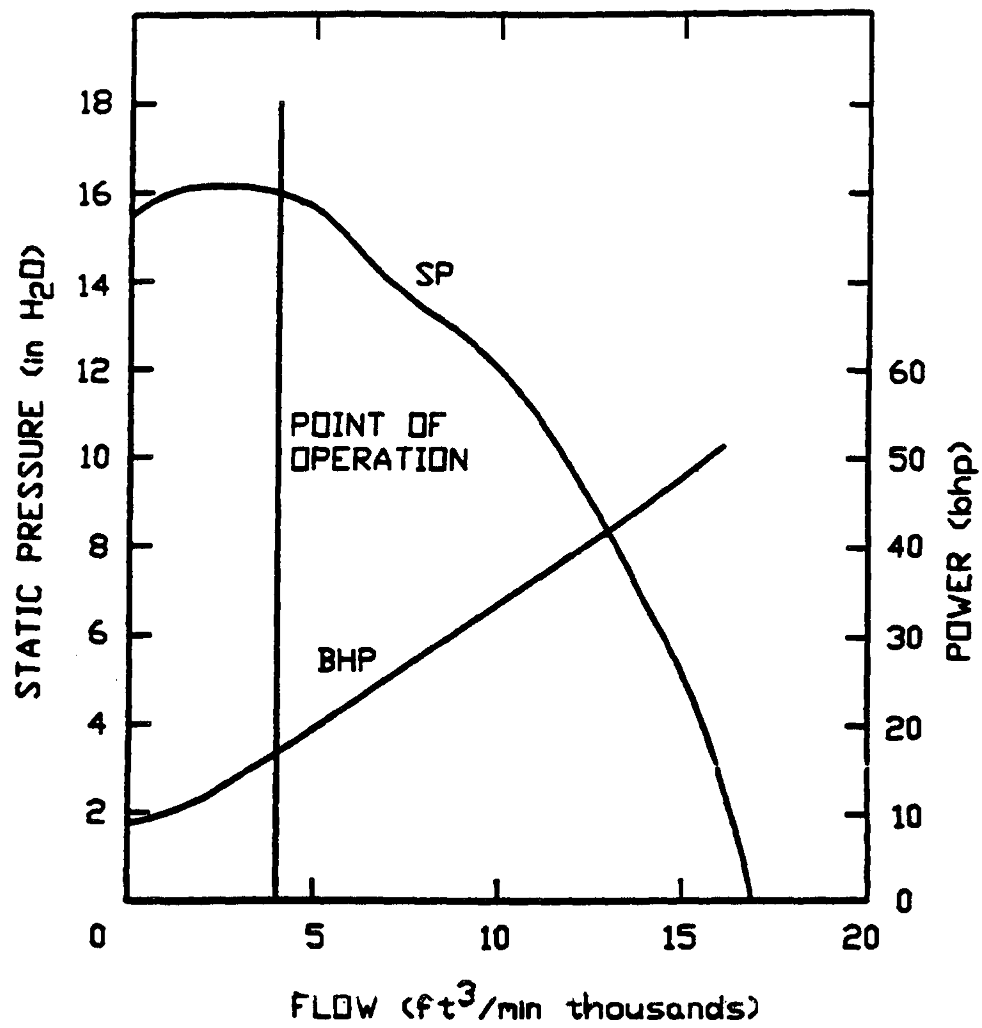
DRESDEN STATION UNITS 2 & 3
CONTROL ROOM ARRANGEMENT
FIGURE 6.4-2



DRESDEN STATION UNITS 2 & 3
GENERAL PLANT LAYOUT
FIGURE 6.4-3



DRESDEN STATION UNITS 2 & 3
CHARCOAL CELL ISOMETRIC
FIGURE 6.5-2



DRESDEN STATION
UNITS 2 & 3

PERFORMANCE CURVE
STANDBY GAS TREATMENT SYSTEM
EXHAUST FAN

FIGURE 6.5-3