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Prairie Island Unit 1 Cycle 21

Final Reload Design Report (Reload Safety Evaluation) and USAR Update

NAD-PI-002
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Prairie Island
Nuclear Generating Plant

Unit 1 Cycle 21

Final Reload Design Report

Reload Safety Evaluation

and USAR Update

NAD-PI-002 Revision 0

December 2000

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Executive Summary

This document contains the Reload Safety Evaluation (RSE) and Final Reload Design Report (FRDR) for Prairie Island Unit 1 Cycle 21 (P121).

Reload Safety Evaluation

The RSE documented in this report is valid for a Unit 1 Cycle 20 end of cycle (EOC) exposure inside the range of 22,948±500 MWd/MTU and a Unit 1 Cycle 21 EOC exposure up to 22,736 MWd/MTU. There are no unreviewed safety questions identified during the RSE process. This cycle meets all limits of the applicable Prairie Island Technical Specifications. The Fuel Criteria Evaluation Process (FCEP) allows extension of the lead rod average burnup limit provided cycle specific design criteria are satisfied. This process has been completed to allow fuel pin exposures up to 62,000 MWd/MTU.

Peaking Factors

The peaking factor limits are defined in WCAP-13919, Addendum 1 (Reference 12) as: $F_{\Delta H} = 1.77$, $F_Q = 2.40$ and P-Bar = 1.59.

Fuel Design

All fuel assemblies loaded for Prairie Island Unit 1 Cycle 21 utilize the Westinghouse Vantage+ fuel design. For the P121 fresh fuel assemblies, only one mechanical design changes was introduced. The only design change involves the change to low cobalt, bead blasted Inconel 718 spring screws for the Top Nozzle springs. The change to low cobalt, bead blasted Inconel 718 Top Nozzle spring screws was recommended by Westinghouse as a preventive measure to reduce the likelihood of spring screw fractures. This design change will not impact the reactor physics or transient analysis modeling.

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Core Design

The core design for this cycle was set by Coordinated Decision 00.013. The P121 reload pattern has 52 fresh assemblies. All fresh assemblies include gadolinia pins for ITC and peaking control. The following is a brief summary of the fresh fuel loading for P121:

Assembly ID	Description	# Assemblies
Y01 – Y16	4.95 $^{w}/_{o}$ U^{235}, 4 pin - 8 $^{w}/_{o}$ Gd	16
Y17 – Y20	4.95 $^{w}/_{o}$ U^{235}, 8 pin - 8 $^{w}/_{o}$ Gd	4
Y21 – Y28	4.95 $^{w}/_{o}$ U^{235}, 12 pin - 8 $^{w}/_{o}$ Gd	8
Y29 – Y52	4.95 $^{w}/_{o}$ U^{235}, 16 pin - 8 $^{w}/_{o}$ Gd	24

Core Design – Extended Burnup Assembly, T81

P121 inserts an extended burnup assembly, T81, in the center assembly location. It is expected to reach a peak pin exposure of 72,717 MWd/MTU to supply test data to Westinghouse for support of an increased Vantage+ fuel burnup limit. The FCEP process was initiated primarily for this bundle. FCEP has been initiated for T81 to allow assembly burnups to 62,000 MWd/MTU. NRC approval is required to burn T81 beyond 62,000 MWd/MTU. The impact of this bundle on core safety has been addressed as part of the RSE. Final approval of this bundle for the P121 core will be addressed under a separate cover.

Cycle Operating Schedule and Exposures

The predicted EOC exposure for P121 is 22,736 MWd/MTU based on a startup date of March 4, 2001, a shutdown date of October 27, 2002, and an EOC exposure for the previous cycle of 22,948±500 MWd/MTU. The predicted EHFP exposure for this cycle is 21,714 MWd/MTU which produces a cycle length of 571 EFPD, and the EOC exposure is based on a coastdown of 31 days.

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1.0 Introduction

This document is the Final Reload Design Report (FRDR) and Reload Safety Evaluation (RSE) for Prairie Island Unit 1 Cycle 21 (P121). This report also serves as the Updated Safety Analysis Report (USAR) for Prairie Island Unit 1 Cycle 21.

Some interesting notes on this cycle include the following:

1. All of the 121 fuel assemblies loaded for P121 utilize the Westinghouse Vantage+ fuel design.
2. There are debris filter bottom nozzles on all fuel assemblies.
3. The 52 fresh Vantage+ fuel assemblies – region 23 (Y bundles) – utilize low cobalt, bead blasted Inconel 718 spring screws for the top nozzle springs.
4. The cycle has peak pin exposures close to 60,000 MWd/MTU for several bundles. Given the possibility of an increased cycle length, some bundles may exceed the 60,000 GWd/MTU limit. In addition, the center assembly, T81, will exceed 60,000 MWd/MTU. FCEP has been initiated for all assemblies that are expected to exceed 60,000 MWd/MTU. Westinghouse approval of the increased pin exposure limits to 62,000 MWd/MTU is documented in Reference 5.
5. P121 inserts an extended burnup assembly, T81, in the center assembly location. It is expected to reach a peak pin exposure of 72,717 MWd/MTU to supply test data to Westinghouse for support of an increased Vantage+ fuel burnup limit. The FCEP process was initiated primarily for this bundle. FCEP has been initiated for T81 to allow assembly burnups to 62,000 MWd/MTU. NRC approval is required to burn T81 beyond 62,000 MWd/MTU. The impact of this bundle on core safety has been addressed as part of the RSE. Final approval of this bundle for the P121 core will be addressed under a separate cover.
6. A constant reactivity bias of 0.00500 Δk (498 pcm) has been applied to the three dimensional nodal models used in the preparation of this report.
7. The predicted EOC exposure for P121 is 22,736 MWd/MTU based on a startup date of March 4, 2001, a shutdown date of October 27, 2002, and an EOC exposure for the previous cycle of 22,948±500 MWd/MTU. The predicted EHFP exposure for this cycle is 21,714 MWd/MTU which produces a cycle length of 571 EFPD, and the EOC exposure is based upon a coastdown of 31 days.
8. The safety analyses performed as part of this RSE have been revised to account for 25% Steam Generator Tube Plugging where appropriate.

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9. The Loss of Coolant Accident (LOCA) has not been evaluated as part of this RSE. LOCA will be addressed under a separate cover.

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2.0 Nomenclature

This section contains brief definitions for many abbreviations and acronyms that will be used throughout the report.

±AO	Positive or negative axial offset conditions
ΔI	Axial Flux Difference, which is the Axial Offset times Fraction of Rated Core Thermal Power
AMSAC/DSS	ATWS Mitigating System Actuation Circuitry
ARI	All Rods In
ARMP	Advanced Recycle Methodology Program
ARO	All Rods Out
ATWS	Anticipated Transients Without Scram
BOC	Beginning Of Cycle
DNB	Departure from Nucleate Boiling
DNBR	Departure from Nucleate Boiling Ratio = $q^{critical}/q$
ECCS	Emergency Core Cooling System
EHFP	Predicted End of Hot Full Power
EFPD	Effective Full Power Days
EOC	Predicted End Of Cycle
EQ	Environment Qualifications
$F_{\Delta H}$	Nuclear Enthalpy Rise Hot Channel Factor
F_Q	Nuclear Heat Flux Hot Channel Factor
FCEP	Fuel Criteria Evaluation Process
FCU	Fan Coil Unit
FPIL	Full Power Insertion Limit
FRDR	Final Reload Design Report
Gd	Gadolinia (Gd_2O_3)
HFP	Hot Full Power
HZP	Hot Zero Power (with T_{mod} = 547 to 535 °F)
ITC	Isothermal Temperature Coefficient
JCO	Justification for Continued Operation
LER	Licensee Event Report
LMSLB	Large Main Steam Line Break

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LOCA	Loss Of Coolant Accident
MDNBR	Minimum DNBR
MOC	Middle Of Cycle
MSS	Main Steam System
MTC	Moderator Temperature Coefficient
NAD	Nuclear Analysis and Design
NMC	Nuclear Management Company
N-1	All control rods fully inserted except for a single fully withdrawn control rod
OPΔT	Overpower ΔT
OTΔT	Overtemperature ΔT
P-bar	Maximum assembly average relative power
P121	Prairie Island Unit 1 Cycle 21 (other cycles are similarly identified using the P*ucc* notation, where *u*=unit number and *cc*=cycle number)
PINGP	Prairie Island Nuclear Generating Plant
PORV	Power Operated Relief Valve
PSOR	Post-Startup and Operations Report
RCCA	Rod Control Cluster Assembly
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RF	Reliability Factor
RSE	Reload Safety Evaluation
SER	NRC Safety Evaluation Report
SI	Safety Injection
SLB	Steam Line Break
SOR	Startup and Operations Report
T_{ave}	Average Reactor Coolant Temperature
T_{in}	Coolant Temperature at Core Inlet
T_{out}	Coolant Temperature at Core Exit
TS	Technical Specifications
USAR	Updated Safety Analysis Report
W	Westinghouse

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3.0 Methodology

This section contains a brief discussion of the core physics and safety analysis methodology. It also briefly discusses reliability factor validation and assessment for this cycle.

3.1 Core Analysis Methods

Nuclear Analysis and Design (NAD) utilizes a calculational model that is a derivative of the Advanced Recycle Methodology Program (ARMP) developed by NAI under EPRI sponsorship. This model utilizes both two and three dimensional reactor core simulations. Only the major codes in this methodology will be discussed.

CASMO-2E (version 90138), a multi-group two dimensional transport theory code, generates cross section data for the two dimensional simulator code, PDQ07, and reactivity coefficient data for the three dimensional core simulator code, N3P.

PDQ07 (version 86017) is used to model discrete pins in a two dimensional quarter core using diffusion theory. The pin power distributions from PDQ07 are used to calculate peaking factors. In addition, PDQ07 is used to adjust, or normalize, the reactivity coefficients and radial power distributions in N3P.

N3P (version 93252) is a nodal code that models the three dimensional core. N3P outputs reactivities, core kinetics, and axial and radial power distributions used in the safety analysis.

FQ1 (version 92224) inputs the three dimensional power distributions from N3P and two dimensional pin power distributions from PDQ07 to compute the peaking factors.

This methdology is consistent with the Qualification of Reactor Physics Methods topical, NSPNAD-8101-A, Revision 1(Reference 9). Generating the physics parameters for the safety analysis was done in accordance with NAD procedure NAP2.102T, Revision 18 (Reference 8).

There have been no revisions to the computer codes that generate physics parameters since the previous Prairie Island reload analysis. Changes were made to the RSE procedure since the last analysis to incorporate minor recommendations from engineers and consultants.

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3.2 Safety Analysis Methods

NAD has developed a bounding type methodology for the safety evaluation. Key physics parameters for the reload design being licensed are reviewed to ensure that the parameters used in the analysis of record are bounding, or if not bounding, that the overall results of the analysis of record are bounding. If the analysis of record shows that the transient meets all the acceptance criteria and is shown to be bounding for the reload of interest, then an analysis for the reload of interest would also show the transient to meet all the acceptance criteria. If the analysis of record is not bounding, NAD analyzes the transient.

NAD uses four codes to model transients for the safety evaluation.

DYNODE-P (version 98104) is used to model the transient response of the nuclear steam supply system.

VIPRE (version 95325) is used to perform the sub-channel analysis using the transient response of the reactor coolant system from DYNODE-P and power distributions from PDQ07 and N3P.

TOODEE2 (version 95128) is used to model the fuel rod thermal response.

CONTEMPT (version 94271) is used to model the containment pressurization and temperature response for a MSLB scenario.

There have been no revisions to the computer codes used for safety analysis since the most recent reload safety evaluation. Changes were made to the RSE procedure (Reference 8) since the last analysis to incorporate minor recommendations from engineers and consultants.

A revision to NSPNAD-8102-PA was approved by the NRC on July 15, 1999. Revision 7 incorporated various corrections to text to either correct minor errors and/or provide improved documentation, and incorporated new methods for determining the minimum required shutdown margin for an inadvertent boron dilution event initiated from subcritical conditions. See Section 6.2.5 for the Boron Dilution event summary. This is the first Unit 1 reload to include the revised transient methods in the FRDR report.

Additionally, NAD received NRC approval for Topical Report, NSPNAD-97002-PA, Rev. 1, "Steam Line Break Methodology," October 2000. The new MSLB methods incorporated the crediting of entrainment out the break, the modeling of heat structures, and the option to utilize an AFW hydraulic model which calculates the AFW flow split between the SGs based on the hydraulic characteristics of the system. See Section 6.2.14 for the Main Steam Line Break event summary.

This methodology is consistent with the Reload Safety Evaluation Methods topical, NSPNAD-8102-PA, Revision 7, with the exception of the Large Steam Line Break analyses which are consistent with the "Steam

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Line Break Methodology" documented in topical report, NSPNAD-97002-PA, Rev. 1. The Small Steam Line Break is consistent between NSPNAD-97002-PA, Rev. 1 and NSPNAD-8102-PA, Rev. 7.

3.3 *Reliability Factor Validation*

The following terms are used to describe quantities related to the statistical methods used to determine the reliability factors and biases of the physics parameters. The term "reliability factor" (RF) describes the allowances to be used in safety related calculations to assure conservatism. The term "uncertainty factor" describes the actual model accuracy. The term "bias" describes the statistical difference between measured data and calculated values.

The NSP models have been benchmarked against Prairie Island measurements in order to quantify the RFs used in safety related calculations. The statistical model used to compute RFs and biases is documented in the Qualification of Reactor Physics Methods Topical, NSPNAD-8101-A, Revision 1, Section 3. Table 3.1 summarizes the biases and RFs used for this RSE.

The safety biases and RFs used for this reload safety evaluation are obtained either from the Topical or from statistical calculations based on the most recent measurements (as documented in the P120 PSOR), whichever is greater. Since the biases and RFs used in the safety evaluation are based on data from prior cycles, they must be verified for the current cycle after startup measurements have been taken.

Two codes are used to calculate safety RFs and biases for F_Q and $F_{\Delta H}$.

SGA (version 92211) is used in flux map processing to compare measured and predicted reaction rates.

SPO (version 96088) computes the statistics on the reaction rate comparisons from SGA in order to calculate the F_Q and $F_{\Delta H}$ RFs and biases.

There have been no changes to the computer programs used to calculate safety RFs and biases since the most recent reload safety evaluation.

3.4 *Methodology and Reliability Factor Assessment*

This section is intended to address the adequacy of current RSE methodology and reliability factor application in the analysis for P121.

The P121 loading pattern compares to the loading patterns of recent cycles in the following respects:

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- This cycle loads 52 fresh assemblies which is 4 assemblies more than normally inserted. The additional assemblies have been inserted for increased cycle length, in order to keep steam generator replacement options open.
- The placement of fresh fuel is similar to the P218 core. In fact, all locations that had fresh fuel inserted in P218 have fresh fuel in P121. There are only two differences between P121 and P218. Four of the 48 fresh assembly locations consistent between the two cycles do not contain the same number of Gadolina pins. P121 also loads 52 fresh assemblies vs. 48 in P218.
- P121 will load 576 gadolinia rods at 8 w/o Gd_2O_3. P220 had 608 gadolinia rods at 8 w/o Gd_2O_3 and P120 had 576 gadolinia rods at 8 w/o Gd_2O_3. The P121 Gd loading is consistent with previous cycles.

In terms of the fresh fuel to be loaded in P121, from a compositional and geometric standpoint, the fuel assembly types and the number of fresh gadolinia rods within given fuel assemblies have all been used in previous cycles. Both the modeling capability (methodology) and reliability factor application for these fuel types have been shown to be acceptable in past cycles and are expected to be acceptable for P121 as well.

In terms of the overall core loading pattern, the core loading strategy used for P121 has not been used in previous cycles. However, the strategy is very similar to those used in recent cycles, including P118 and P218. The only difference between these cycles is the 4 additional assemblies that have been loaded in P121 (P118 and P218 were 48 assembly cycles). The modeling capability and reliability factor application for these core designs have been shown to be acceptable and are expected to be acceptable for P121.

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Table 3.1

Prairie Island Unit 1 Cycle 21
RSE Reliability Factors and Biases

Item	RF	Bias
$F_{\Delta H}$	0.044	0.000
F_Q	0.062	0.015
Doppler Coefficient[1]	0.10	0
Doppler Coefficient[2]	-0.20	0
Doppler Defect	0.20	0
Control Rod Worth	0.10	0
Boron Worth	0.10	0
Temperature Coefficient[1]	2.9 pcm/°F	-0.03 pcm/°F
Temperature Coefficient[2]	1.81 pcm/°F	1.16 pcm/°F
Delayed Neutron Fraction, β	0.04	0
Prompt Neutron Lifetime, ℓ^*	0.04	0

1 Used for transients requiring the most negative coefficient.
2 Used for transients requiring the least negative coefficient.

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4.0 Cycle 21 Core Design

The core design for this cycle was approved by Coordinated Decision 00.013. The core loading pattern is shown by assembly ID and fuel type in Figure 4.1. The P121 reload pattern has 52 fresh assemblies. All fresh assemblies include gadolinia pins for ITC and peaking control. The following is a brief summary of the fresh fuel loading for P121:

Assembly ID	Description	# Assemblies
Y01 – Y16	4.95 $^{w}/_{o}$ U^{235}, 4 pin - 8 $^{w}/_{o}$ Gd	16
Y17 – Y20	4.95 $^{w}/_{o}$ U^{235}, 8 pin - 8 $^{w}/_{o}$ Gd	4
Y21 – Y28	4.95 $^{w}/_{o}$ U^{235}, 12 pin - 8 $^{w}/_{o}$ Gd	8
Y29 – Y52	4.95 $^{w}/_{o}$ U^{235}, 16 pin - 8 $^{w}/_{o}$ Gd	24

Also, P121 inserts an extended burnup assembly, T81, in the center bundle location. It is expected to reach a peak pin exposure of 72,717 MWd/MTU, 10,717 MWd/MTU beyond the current license limit of 62,000 MWd/MTU to supply test data to Westinghouse to support increasing the Vantage+ burnup limit. The impact of this bundle on core safety has been addressed in the RSE. Final approval of this bundle for the P121 core will be addressed under a separate cover.

The central region and the annular pellet blankets of the non-gadolinia fuel pins are enriched to 4.95 $^{w}/_{o}$ U^{235}. In the 52 fresh assemblies containing the 4.95 $^{w}/_{o}$ U^{235} fuel, the central region of the gadolinia pins is enriched to 2.97 $^{w}/_{o}$ U^{235} and the blanket regions are enriched to 3.95 $^{w}/_{o}$ U^{235}.

All fuel assemblies loaded for Prairie Island Unit 1 Cycle 21 utilize the Westinghouse Vantage+ fuel design. Vantage+ was designed to have a higher exposure limit than the OFA and HB-OFA designs previously used at Prairie Island. The use of ZIRLO cladding instead of zircaloy-4 increases resistance to corrosion by the coolant. Annular pellets in the upper and lower 6 inches of the active fuel region of the non-gadolinia fuel pins increases the free volume available for fission gasses to accumulate. The gadolinia fuel pins, which are made by General Electric, have solid pellets throughout the entire active fuel region. This is acceptable because the gadolinia pins will not achieve as high of exposures as the non-gadolinia pins, and thus require less free volume for fission gas accumulation. The fuel pins have also been shortened to allow for more linear expansion expected as a result of the higher exposures. The Vantage+ design includes a debris filtering bottom nozzle and anti-snag top and bottom grids.

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For the P121 fresh fuel assemblies (Region 23, Y assemblies), only one mechanical design change was introduced. The only design change involves the change to low cobalt, bead blasted Inconel 718 spring screws for the Top Nozzle springs. The change to low cobalt, bead blasted Inconel 718 Top Nozzle spring screws was recommended by Westinghouse as a preventive measure to reduce the likelihood of spring screw fractures. This design change will not impact the reactor physics or transient analysis modeling.

The RSE documented in this report uses an EOC exposure of 22,736 MWd/MTU based on a startup date of March 4, 2001 and a shutdown date of October 27, 2002. The RSE is valid for an EOC exposure for the previous cycle of 22,948 ±500 MWd/MTU.

Table 4.1 lists the fuel assemblies used in the core pattern and their exposures at BOC based on a P120 EOC exposure of 22,948 MWd/MTU. Table 4.2 lists predicted exposures and exposure limits for various groups of assemblies at the P121 EOC exposure of 22,736 MWd/MTU.

The boron letdown curve for P121 is presented in Figure 4.2. This figure presents the critical boron concentration in ppm as a function of cycle exposure.

The peaking factor limits for this cycle are as follows: F_Q = 2.40, $F_{\Delta H}$ = 1.77, and P-bar = 1.59. Figure 4.3 presents the calculated F_Q value for P121, in percent of the limit, as a function of cycle exposure. Figure 4.4 presents the calculated $F_{\Delta H}$ value for P121, in percent of the limit, as a function of cycle exposure. The calculated peak assembly average power (P-bar) value for P121, in percent of the limit, is presented as a function of cycle exposure in Figure 4.5.

Figures 4.6 to 4.11 present the P121 quarter-core assembly power and exposure distributions at cycle exposures of 100, 12,000, and 21,714 (EHFP) MWd/MTU, respectively.

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Table 4.1

Prairie Island Unit 1 Cycle 21

Assembly Types and BOC Exposures

Bundle Type	Initial Cycle Inserted	Assembly I.D.	Number of Assemblies	Initial Enrichment ($^{w}/_{o}$ U^{235})	Initial Gadolinia Enrichment ($^{w}/_{o}$ Gd_2O_3)	# of Gd_2O_3 Bearing Pins/Assembly	BOC Average Exposure (MWd/MTU)
W VANTAGE+	P216	T81	1	4.95	6	12	51,470
W VANTAGE+	P119	W01-W08	8	4.95	--No Gad--		46,580
W VANTAGE+	P119	W09-W16	8	4.95	8	4	47,614
W VANTAGE+	P119	W41-W44	4	4.95	8	16	45,231
W VANTAGE+	P120	X01-X08	8	4.95	8	4	22,914
W VANTAGE+	P120	X09-X24	16	4.95	8	8	26,335
W VANTAGE+	P120	X25-X28	4	4.95	8	12	27,585
W VANTAGE+	P120	X29-X36	8	4.95	8	16	30,830
W VANTAGE+	P120	X37-X48	12	4.95	8	20	30,460
W VANTAGE+	P121	Y01-Y16	16	4.95	8	4	0
W VANTAGE+	P121	Y17-Y20	4	4.95	8	8	0
W VANTAGE+	P121	Y21-Y28	8	4.95	8	12	0
W VANTAGE+	P121	Y29-Y52	24	4.95	8	16	0

* Average Enrichment

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Table 4.2

Prairie Island Unit 1 Cycle 21

Maximum Predicted EOC Exposures by Fuel Region

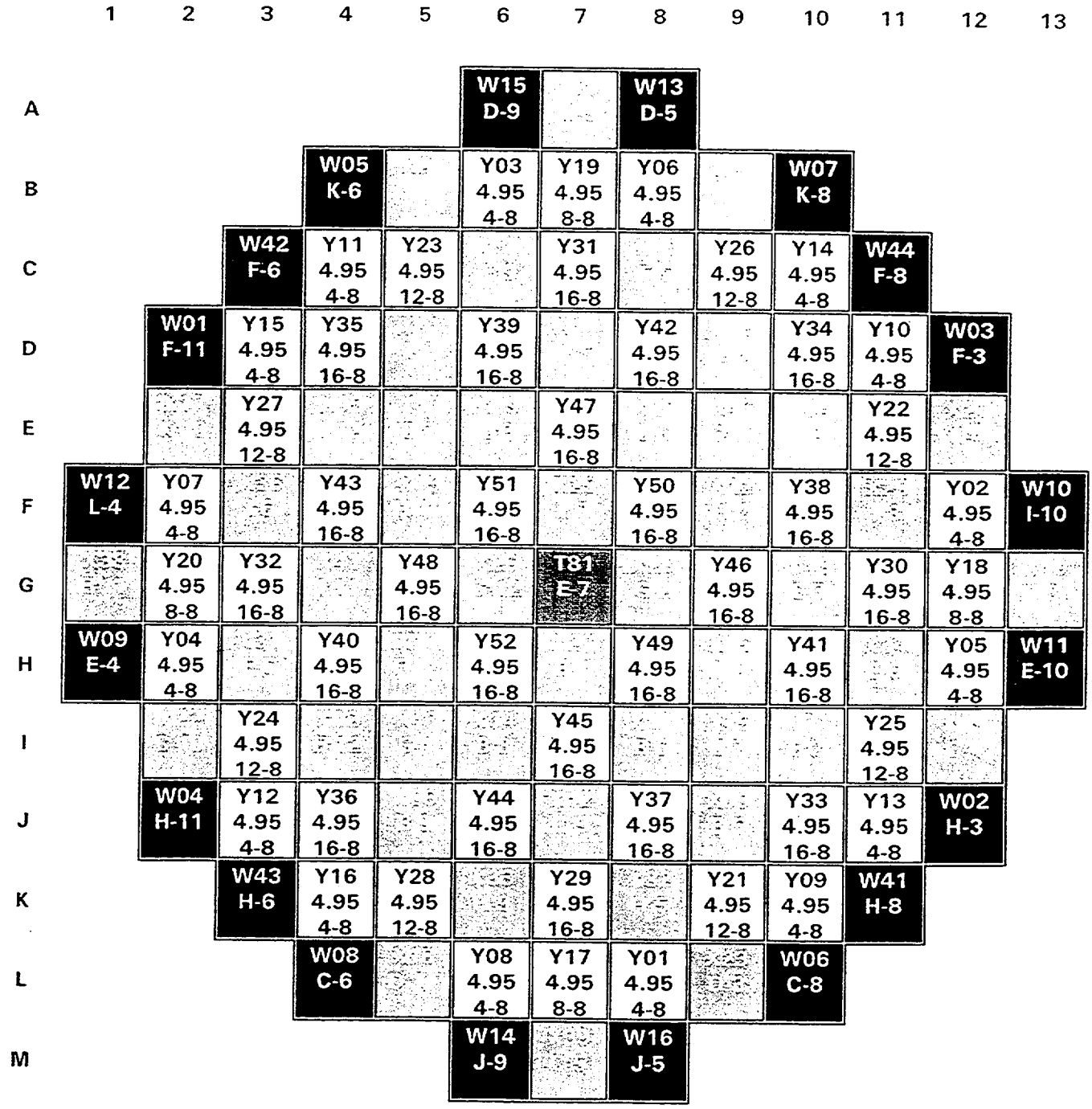
(Based on EOC exposure = 22,736 MWd/MTU)

Bundle Type	Initial Cycle Inserted	Number of Assemblies	Average Assembly Exposure (MWd/MTU)	Maximum Assembly Exposure (MWd/MTU)	Maximum Pin Exposure (MWd/MTU)	Maximum Pellet Exposure (MWd/MTU)
W VANTAGE+ (T81) 4.95	P216	1	69,140	69,140	72,717	76,429
W VANTAGE+ (W01-W08) 4.95	P119	8	54,550	54,552	57,185	61,303
W VANTAGE+ (W09-W16) 4.95	P119	8	54,890	54,897	58,342	61,928
W VANTAGE+ (W41-W44) 4.95	P119	4	54,809	54,811	58,455	61,612
W VANTAGE+ (X01-X08) 4.95	P120	8	49,720	49,721	56,680	61,409
W VANTAGE+ (X09-X24) 4.95	P120	16	47,135	52,906	58,805	63,117
W VANTAGE+ (X25-X28) 4.95	P120	4	52,127	52,143	58,589	62,647
W VANTAGE+ (X29-X36) 4.95	P120	8	54,704	54,708	59,048	63,269
W VANTAGE+ (X37-X48) 4.95	P120	12	50,260	55,096	59,315	63,542
W VANTAGE+ (Y01-Y16) 4.95	P121	16	25,636	25,701	31,768	35,126
W VANTAGE+ (Y17-Y20) 4.95	P121	4	27,859	27,859	32,804	36,442
W VANTAGE+ (Y21-Y28) 4.95	P121	8	29,011	29,012	32,934	36,174
W VANTAGE+ (Y29-Y52) 4.95	P121	24	31,136	31,676	34,780	37,696

Note: All assemblies have a maximum pin exposure limit of 62,000 MWd/MTU. Final approval to burn T81 past 62,000 MWd/MTU will be addressed under a separate cover.

The P121 core average exposure for an EOC exposure of 22,736 MWd/MTU is 41,872 MWd/MTU.

Figure 4.1
Prairie Island Unit 1 Cycle 21
Core Loading Pattern



Bundle ID P2 17 Location

Bundle ID $^{w}/_{o}$ U^{235} # - $^{w}/_{o}$ Gd

P12 Cycle 16, Twice Burned 4.95 $^{w}/_{o}$ U^{235}

P11 Cycle 21, Fresh 4.95 $^{w}/_{o}$ U^{235}

P11 Cycle 20, Once Burned 4.95 $^{w}/_{o}$ U^{235}

Bundle ID P120 Location

P11 Cycle 19, Twice Burned 4.95 $^{w}/_{o}$ U^{235}

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Figure 4.2

Prairie Island Unit 1 Cycle 21

Boron Letdown vs. Cycle Exposure

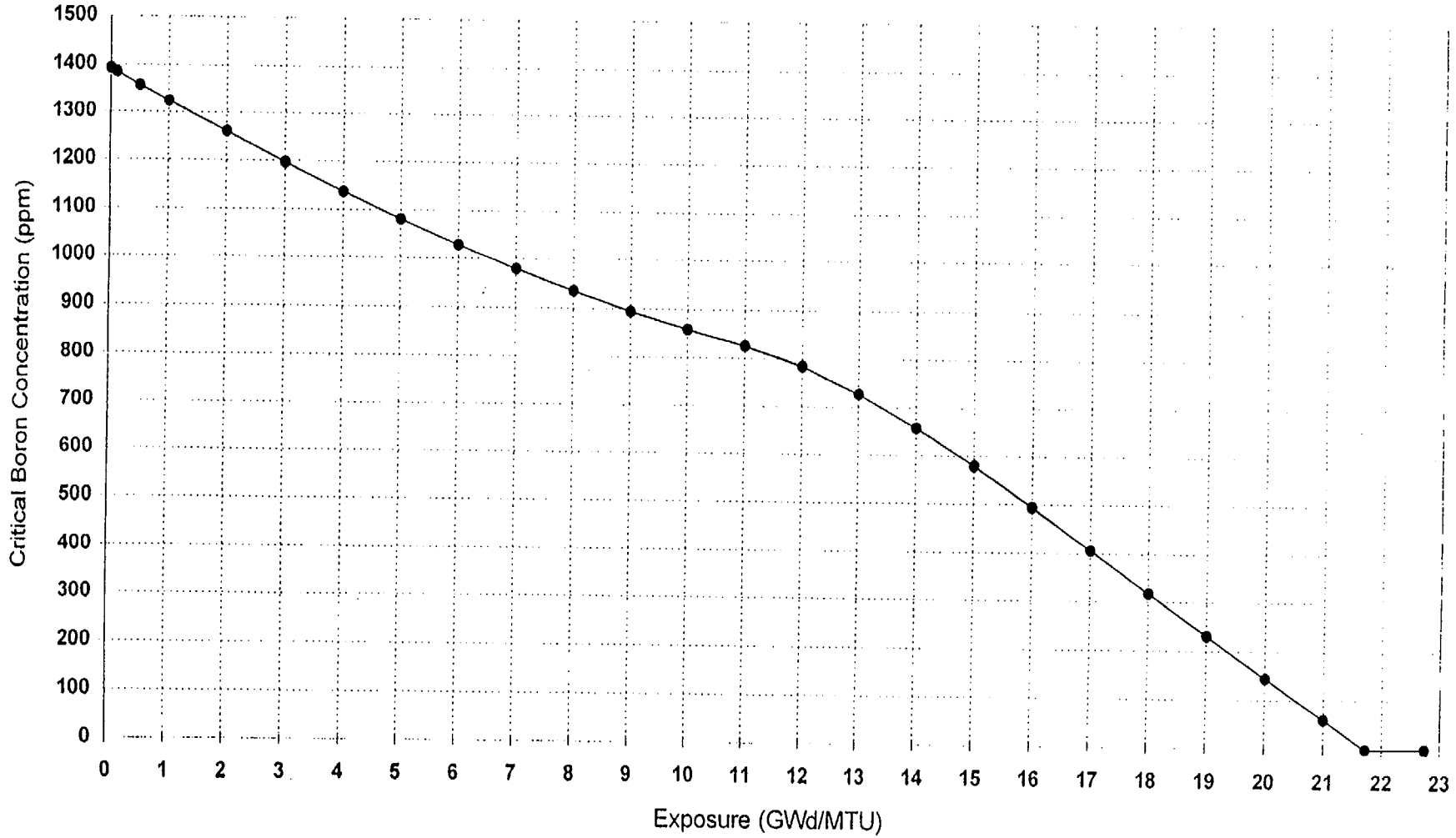

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Figure 4.3

Prairie Island Unit 1 Cycle 21

F_Q % of 2.40 Limit vs. Cycle Exposure
(Using design bias and RF)

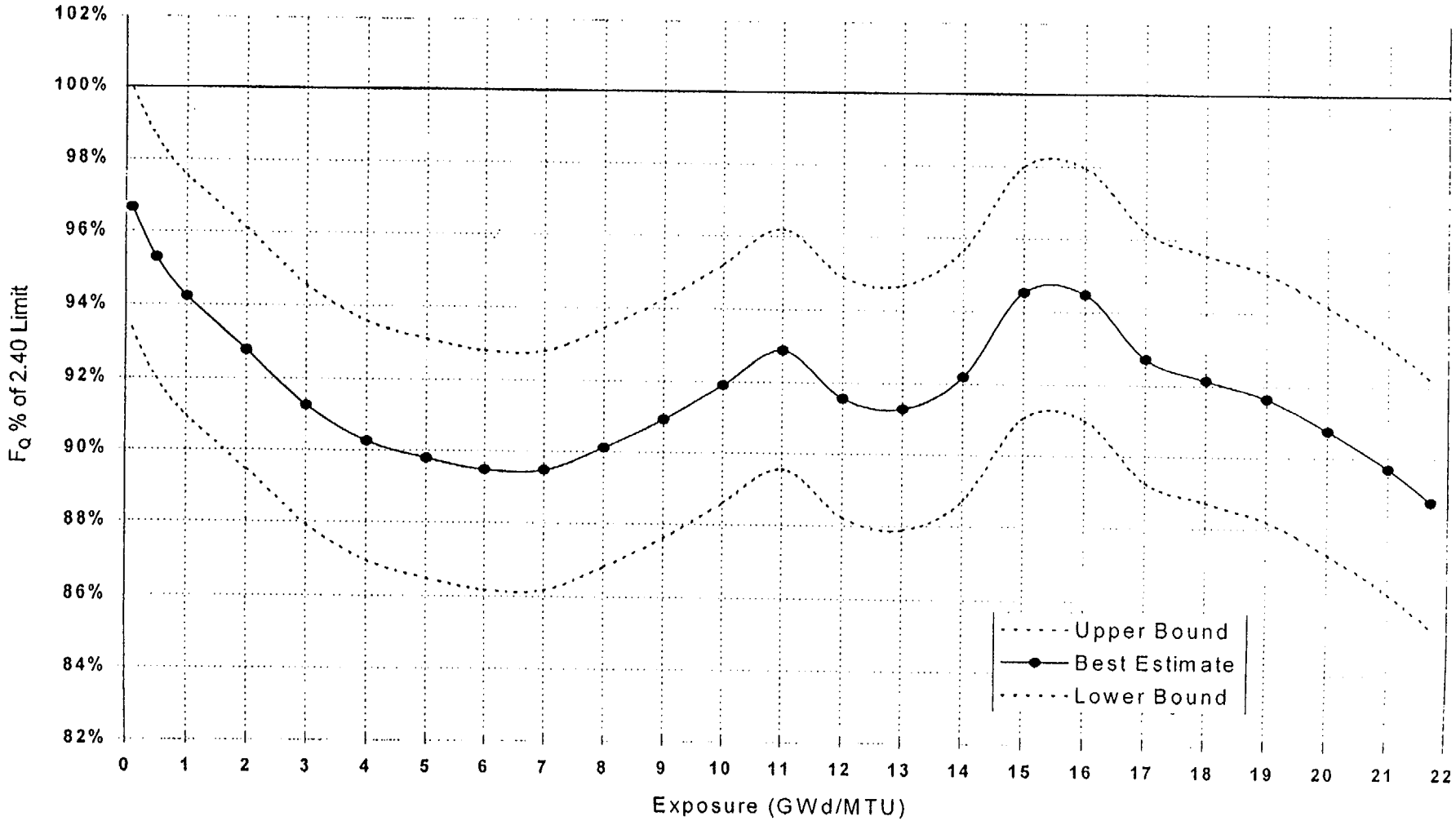

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Figure 4.4

Prairie Island Unit 1 Cycle 21

$F_{\Delta H}$ % of 1.77 Limit vs. Cycle Exposure
(Using design bias and RF)

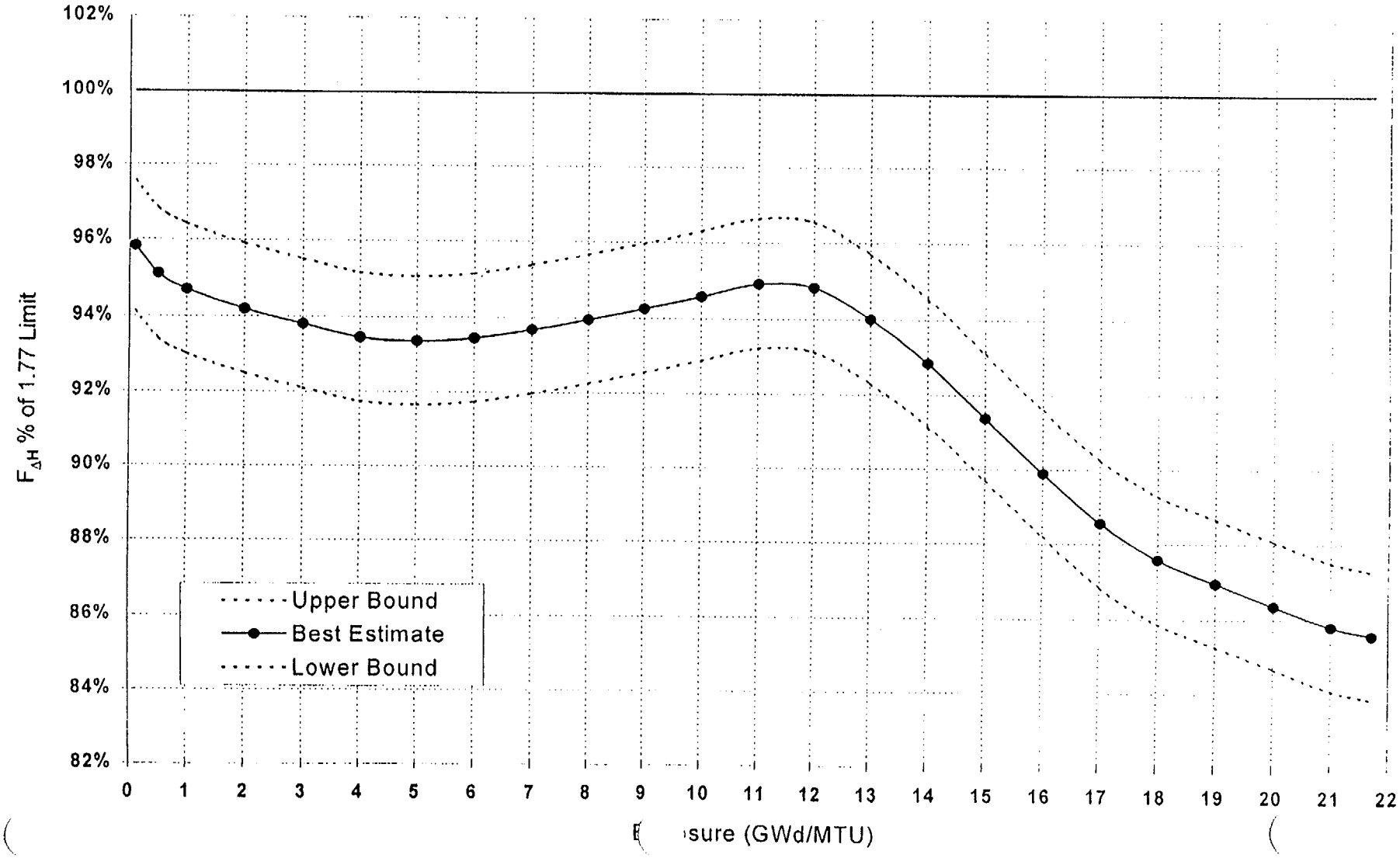

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Figure 4.5

Prairie Island Unit 1 Cycle 21

P-bar % of 1.59 Limit vs. Cycle Exposure

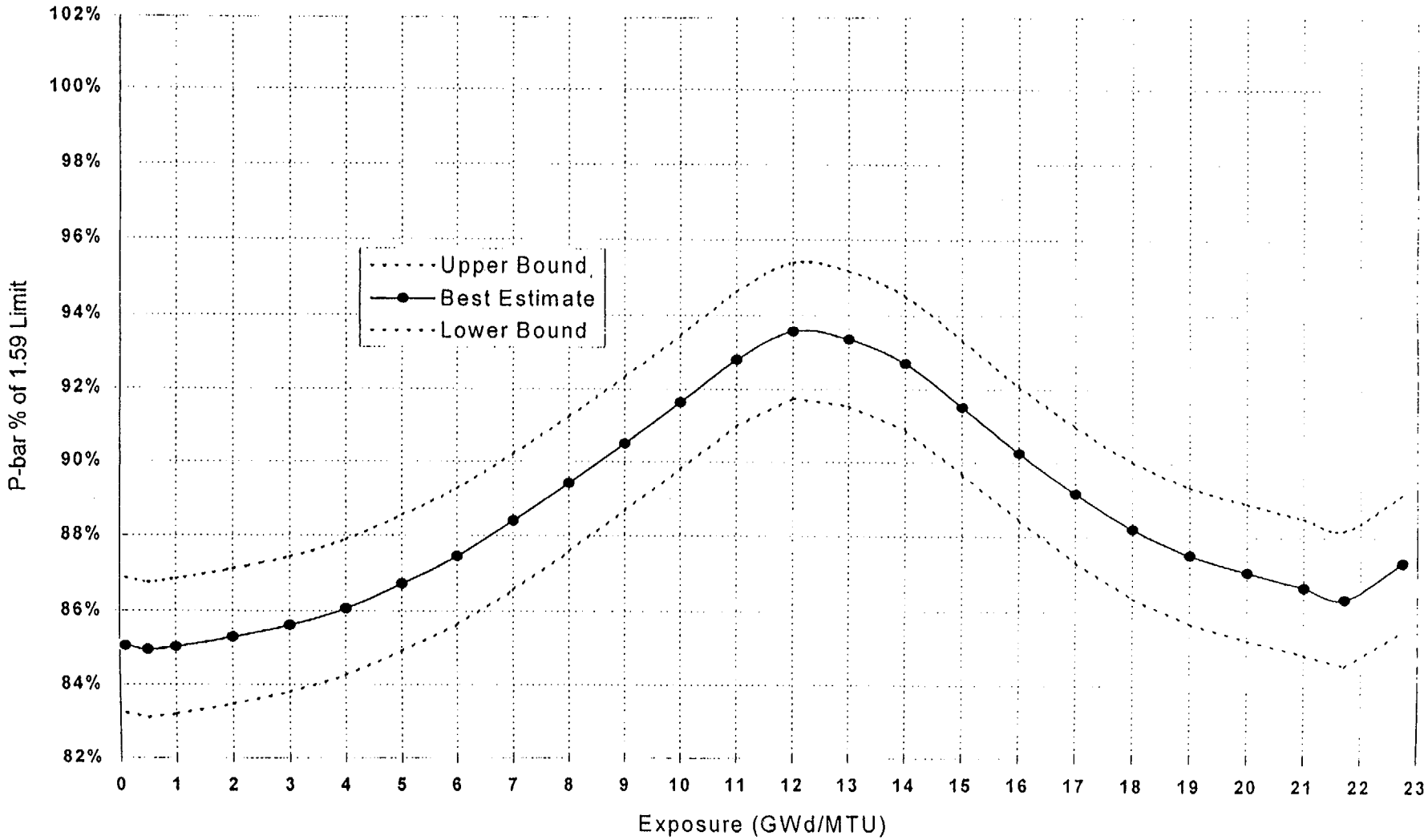

Figure 4.6

Prairie Island Unit 1 Cycle 21

Power Distribution at 100 MWd/MTU

	7	8	9	10	11	12	13
G	0.72	1.07	1.32	1.09	1.31	1.25	0.45
H	1.07	1.30	1.17	1.33	1.07	1.18	0.30
I	1.32	1.17	1.10	1.26	1.27	1.69	
J	1.09	1.33	1.26	1.32	1.15	0.32	
K	1.31	1.07	1.27	1.15	0.39		
L	1.26	1.18	0.69	0.32			
M	0.45	0.30					

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Figure 4.7

Prairie Island Unit 1 Cycle 21

Exposure Distribution at 100 MWd/MTU
(in MWd/MTU)

	7	8	9	10	11	12	13
G	51,542	27,691	132	30,045	131	126	29,980
H	27,691	130	27,292	134	30,946	118	47,639
I	132	27,290	31,620	23,044	127	25,550	
J	30,044	134	23,037	132	114	46,608	
K	131	30,930	127	114	45,269		
L	126	118	25,578	46,612			
M	29,981	47,646					

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Figure 4.8

Prairie Island Unit 1 Cycle 21

Power Distribution at 12,000 MWd/MTU

	7	8	9	10	11	12	13
G	0.79	1.11	1.47	1.12	1.40	1.20	0.45
H	1.11	1.43	1.15	1.43	1.04	1.09	0.31
I	1.47	1.15	1.02	1.17	1.27	0.67	
J	1.12	1.43	1.17	1.35	1.10	0.34	
K	1.40	1.04	1.27	1.10	0.41		
L	1.20	1.09	0.67	0.34			
M	0.45	0.30					

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Figure 4.9

Prairie Island Unit 1 Cycle 21

Exposure Distribution at 12,000 MWd/MTU
(in MWd/MTU)

	7	8	9	10	11	12	13
G	60,666	40,709	16,532	43,267	16,063	14,646	35,409
H	40,718	16,220	41,115	16,404	43,606	13,630	51,251
I	16,537	41,122	44,447	37,553	15,179	33,744	
J	43,268	16,430	37,552	15,923	13,462	50,566	
K	16,065	43,599	15,182	13,463	50,068		
L	14,647	13,625	33,768	50,569			
M	35,411	51,249					

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Figure 4.10

Prairie Island Unit 1 Cycle 21

Power Distribution at 21,714 MWd/MTU

	7	8	9	10	11	12	13
G	0.80	1.03	1.35	1.05	1.35	1.25	0.54
H	1.03	1.32	1.06	1.34	1.02	1.16	0.38
I	1.35	1.06	0.97	1.11	1.29	0.75	
J	1.05	1.34	1.11	1.33	1.16	0.41	
K	1.35	1.02	1.29	1.16	0.48		
L	1.25	1.16	0.75	0.41			
M	0.54	0.38					

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Figure 4.11

Prairie Island Unit 1 Cycle 21

Exposure Distribution at 21,714 MWd/MTU
(in MWd/MTU)

	7	8	9	10	11	12	13
G	68,340	51,082	30,297	53,865	29,571	26,570	40,186
H	51,098	29,688	51,817	29,962	53,654	24,513	54,510
I	30,302	51,829	54,105	48,587	27,687	40,598	
J	53,865	30,004	48,587	29,049	24,393	54,132	
K	29,572	53,650	27,690	24,393	54,321		
L	26,570	24,502	40,618	54,134			
M	40,187	54,498					

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5.0 Thermal Hydraulic Design Analysis

This section provides the results of the thermal hydraulic design analyses for Prairie Island Unit 1 Cycle 21.

5.1 Design Criteria

The thermal hydraulic design performance requirements for W fuel designs which use ZIRLO clad material are as follows:

1. The minimum DNBR using the WRB-1 correlation with corrections for non-uniform heating and rod bow will be ≥ 1.17 during Condition I and II events.

   The minimum DNBR using the W-3 correlation with corrections for non-uniform heating and rod bow will be 1.45 in the range of 500-1000 psia and 1.30 for pressures greater than 1000 pisa. The W-3 correlation is used for the large steam line break transient because the RCS pressure drops below the range of the WRB-1 correlation.

2. The fuel must be thermally and hydraulically compatible with the existing fuel and the reactor core throughout the life cycle of the fuel.

3. The maximum fuel temperature at the design overpower shall not exceed 4700°F for UO_2 rods. Westinghouse fuel temperature analyses show that fuel melt will not occur for local powers up to 22.83 kW/ft for non-gadolinia rods, 17.39 kW/ft for 6 w/o gadolinia rods and 16.28 kW/ft for 8 w/o gadolinia rods.

4. The cladding temperature limits will be met by complying with the minimum DNBR limit for those events in which there are no fuel failures. These temperature limits were considered in the fuel rod design by W.

5. The fuel temperature and cladding strain limits, consistent with the acceptance criteria of Standard Review Plan 4.2, shall not be exceeded for rod drop or misalignment events.

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5.2 *Thermal Margin*

The transient with the least thermal margin for P121 is the Uncontrolled RCCA Withdrawal at Power transient. The minimum DNBR for this transient was 1.180 with the rod bow penalty of 2.6% and an engineering factor of 1.03 applied to it. Section 6.2.2 contains more information about how this transient was modeled.

5.3 *Rod Bow*

The calculation of the reduction of DNBR due to rod bowing is described in detail in Reference 2. The penalty takes the form of the following:

$$DNBR_B = DNBR_{NB} (1 - \delta)$$

where $DNBR_{NB}$ is the minimum DNBR computed without rod bow and δ is the rod bow penalty. For W 14x14 OFA, HB-OFA, and Vantage+ fuels, δ=0.026.

The rod bow penalty is based on an average assembly burnup of 33,000 MWd/MTU. While the amount of rod bowing increases beyond this exposure, the fuel is not capable of achieving limiting peaking factors due to the decrease in fissionable isotopes and the buildup of fission product inventory. The physical burndown effect is greater than the rod bowing effects which would be calculated based on the amount of bow predicted at those burnups. Therefore, for the purpose of evaluating effects of rod bow on Westinghouse fuel, 33,000 MWd/MTU represents the maximum assembly average burnup of concern.

For P121, the transient with the least margin to DNB was the Uncontrolled RCCA Withdrawal at Power transient. The unbowed and bowed MDNBR values, including engineering uncertainty, are 1.211 and 1.180, respectively. The bowed and unbowed MDNBR results are above the allowable 1.17 limit. Thus, no reduction in allowable reactor peaking factors are required as a result of a change in DNBR due to rod bow.

5.4 *Fuel Temperature Analysis*

The fuel temperature analyses for P121 show that fuel melt will not occur for Condition I and II events.

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5.5 *Safety Limit Curves*

Safety limit curves for Prairie Island are given in Prairie Island Technical Specifications (TS) Section 2.1. These curves define the region of acceptable operation in terms of core average temperature, power, and pressure. The safety limit curves represent a loci of points which correspond to the design limits of the reactor which include maximum core outlet temperature and DNB.

The safety limit curves currently in place, TS Figure 2.1-1, Rev. 123 are bounding for Prairie Island Unit 1 Cycle 21. The core remains protected by the locus of points where the steam generator (main steam) safety valves open and the overtemperature and overpower delta-T ($OT\Delta T$ & $OP\Delta T$) trip functions as defined in TS 2.3, Rev. 91. The current $f(\Delta I)$ function which is part of the $OT\Delta T$ trip function is also valid for this cycle. Note that the steam generator locus used in the evaluation of both the safety limit curves is valid for a ±3% tolerance on the steam generator safety valves.

The applicability of the safety limit curves is evaluated each cycle as defined in NAD technical procedure NAP3.101T, Revision 1.

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6.0 Transient and Accident Analysis

This reload safety evaluation was performed to help address the following questions that must be answered as part of all 10CFR50.59 safety evaluations. The answers provide the basis for determining if a proposed activity involves an unreviewed safety question.

a) May the proposed activity increase the consequences of an accident previously evaluated in the USAR or in a pending USAR submittal?

b) May the proposed activity increase the probability of occurrence of an accident previously evaluated in the USAR or in a pending USAR submittal?

c) May the proposed activity increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the USAR or in a pending USAR submittal?

d) May the proposed activity increase the consequences of a malfunction of equipment important to safety previously evaluated in the USAR or in a pending USAR submittal?

e) May the proposed activity create the possibility of an accident of a different type than previously evaluated in the USAR or in a pending USAR submittal?

f) May the proposed activity create the possibility of a different type of malfunction of equipment important to safety than any previously evaluated in the USAR or in a pending USAR submittal?

g) Does the proposed activity reduce the margin of safety as defined in the basis for any Technical Specification?

As part of all reload safety evaluations, NAD evaluates the accidents listed in Chapter 14 of the USAR to determine if the current analyses bound the reload design. All transients that are not bounded by analyses of record are reanalyzed and the results are presented in the RSE. All the transients are run in accordance with the USAR, the Reload Safety Evaluation Methods topical NSPNAD-8102-PA, Revision 7, and the Steam Line Break Methods Topical NSPNAD-97002-PA, Rev. 1. This section summarizes the results of the accident and transient analysis for the P121 RSE. The AMSAC/DSS analysis documented in USAR §14.8 was reviewed for this reload and determined to be appropriate and bounding. The AMSAC/DSS results and plots are documented in §14.8; therefore, that information will not be included in this report. The analyses of record for the transients and accidents evaluated by NAD are identified in Reference 7.

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In regards to fuel design changes introduced for this reload, the results and conclusions of the USAR Chapter 14 analyses of record are not impacted by the change to low cobalt, bead blasted Inconel 718 Top Nozzle spring screws.

6.1 Design Limits

The following design limits for Prairie Island Unit 1 Cycle 21 remain the same as in past analyses:

a) The maximum RCS pressure for transients other than rod ejection is 2750 psia which is 110% of the design pressure (2500 psia).

b) The maximum RCS pressure for rod ejection is 3000 psia which is 120% of the design pressure (2500 psia).

c) The maximum main steam line pressure is 1210 psia which is 110% of the design pressure (1100 psia).

d) The maximum clad temperature is 2750°F.

e) The DNBR limit for the WRB-1 correlation is ≥ 1.17 for W OFA and Vantage+ fuel. This value is the limit for all transients except large steam line break.

f) The DNBR limit for the large steam line break transient is ≥ 1.45 using the W-3 correlation for W OFA and Vantage+ fuel for pressures between 500 - 1000 psia. For pressures greater than 1000 psia, the DNBR limit is ≥ 1.30.

g) The average hot spot fuel enthalpy limit is 280 cal/g.

h) The maximum design pressure for containment is 46 psig.

i) The limits of 10CFR50.46 apply for the LOCA evaluation.

j) The maximum differential pressure across the Steam Generator tubes for a MSLB event is 2560 psi.

k) The fuel temperature and cladding strain limits, consistent with the acceptance criteria of Standard Review Plan 4.2 shall not be exceeded for Control Rod Misalignment or Control Rod Drop events.

The peaking factor limits are defined in WCAP-13919, Addendum 1 (Reference 12). The limits are: $F_Q \leq 2.40$, $F_{\Delta H} \leq 1.77$, and P-bar ≤ 1.59.

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6.2 *Transient/Accident Summaries*

This section contains short summaries of the transients and accidents for which NAD performs analyses. The results contained in the following summaries are also listed in Table 6.1. The HFP initial conditions used for the transient analyses are listed in Table 6.2. In Table 6.3 is a list of all reactor trip setpoints and delay times used in the transient analyses. Transients adversely affected by higher steam generator tube plugging levels were analyzed at 25% tube plugging. All transient analyses limiting at HZP conditions are valid down to a moderator temperature of 535°F.

6.2.1 Uncontrolled RCCA Withdrawal from Subcritical

This transient was not run for P121 because the results from the P216 analysis bound this reload.

This transient is initiated with a reactivity insertion rate assumed to be equal to the maximum worth of two rod banks moving simultaneously at maximum speed through the region of highest differential worth. The reactor is initially at HZP.

The following are the results from the bounding P216 analysis: The reactor reached prompt criticality about 6.4 seconds after the rods started to withdraw and tripped on overpower. Doppler feedback turned the power around before the rods dropped. Although the reactor was predicted to experience a power spike of 561%, the heat flux remained small enough not to cause any fuel damage. The average heat flux was less than 41.7% of the full power average heat flux.

The Uncontrolled RCCA Withdrawal from Subcritical satisfies all acceptance criteria.

6.2.2 Uncontrolled RCCA Withdrawal at Power

This transient was not run for P121 because the results from the P219 analysis bound this cycle.

This transient is evaluated for a range of reactivity insertion rates with the maximum reactivity insertion rate assumed to be equal to the maximum worth of two rod banks moving simultaneously at maximum speed through the region of highest differential worth.

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This transient is divided into three separate analyses:

a) Fast RCCA withdrawal maximizing the RCS pressure response

b) Slow RCCA withdrawal maximizing the MSS pressure response

c) Slow RCCA withdrawal minimizing DNBR

The fast RCCA withdrawal maximizing the RCS pressure response produced a maximum RCS pressure of 2581 psia for an initial core power of 10% of rated power. The design limit for the RCS pressure is 2750 psia. An analysis performed over a range of initial core powers demonstrated that the maximum RCS pressure decreases with increasing initial core power.

The slow RCCA withdrawal maximizing the MSS pressure response produced a maximum steam generator pressure of 1184 psia for an initial core power of 10% of rated power. The design limit for the MSS pressure is 1210 psia. An analysis performed over a range of initial core powers demonstrated that for core powers above 50% of rated power the maximum MSS pressure decreases with increasing initial core power. The same analysis indicated that there is very little sensitivity to core power for core powers at or below 50% of rated power.

The slow RCCA withdrawal minimizing DNBR produced a minimum DNBR of 1.180 for an initial core power of 10% of rated power. The design limit for the minimum DNBR is 1.17. An analysis performed over a range of initial core powers demonstrated that the minimum DNBR increases with increasing initial core power.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.2-1 through 6.2.2-8.

The Uncontrolled RCCA Withdrawal at Power satisfies all acceptance criteria.

6.2.3 Control Rod Misalignment

This transient was not run for P121 because the results from the P218 analysis bound this reload.

The Control Rod Misalignment transient is modeled as a steady state full power condition with D-bank inserted to FPIL with one rod stuck out in the fully withdrawn position. The minimum DNBR for these conditions was calculated to be 1.201.

The Control Rod Misalignment transient satisfies all acceptance criteria.

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6.2.4 Dropped Rod

This transient has been performed for P121. It has been performed to update the analysis and input new physics parameters to conclusively bound all dual rod drops and to address the new statepoint methodology being incorporated by PINGP to increase the high negative neutron flux rate trip setpoint from 7% to 10%.

In this transient a full-length RCCA is assumed to be released by the stationary gripper coils and to fall into a fully inserted position in the core. The drop of a single RCCA may or may not result in a negative flux rate reactor trip. If a trip does not occur, the rod controller circuitry could cause a transient power overshoot. The power overshoot combined with the higher peaking factors associated with a dropped rod could challenge the DNBR limit.

From the P121 analysis, the minimum DNBR was 1.277 at 28.1 seconds.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.4-1 through 6.2.4-3.

The Dropped Rod event satisfies all acceptance criteria.

6.2.5 Uncontrolled Boron Dilution

This transient is divided into two separate conditions. The first is consistent with the FSAR analysis and only considers boron dilution events which are initiated from a critical condition. The second is consideration for boron dilution events which are initiated from subcritical conditions. Both methodologies are described in Reference 10.

For the critical initial condition, this transient is a reactivity insertion event like the Uncontrolled RCCA Withdrawal at Power transient. In fact, the only significant difference is that the reactivity insertion rate is caused by boron dilution instead of rod withdrawal. Since the limiting reactivity insertion rate was considered in the Uncontrolled RCCA Withdrawal transient, the reactivity insertion rate from a boron dilution cannot produce more limiting results with respect to DNB or RCS pressure. Therefore, the Uncontrolled RCCA Withdrawal transient, which satisfies all acceptance criteria, bounds the Uncontrolled Boron Dilution transient.

For the subcriticality initial condition, the approach is to define new shutdown margin requirements for each mode of operation. The new requirements will assure at least 24 minutes from the time the dilution event started until sustained criticality was achieved. The analysis is a function of operational mode, the number of charging pumps available and the minimum active RCS volumes for each operating mode.

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The shutdown margin requirements assumed in the analysis of record are summarized in Section 6.4.

The analysis of record demonstrates that the above shutdown margins define the soluble boron concentrations that satisfy the boron dilution acceptance criteria.

6.2.6 Startup of an Inactive Loop

The Startup of an Inactive Loop has been performed for P121. This change was made to address the new statepoint methodology being incorporated by PINGP to increase the rated thermal power in the permissive #8 setpoint from 10% to 17%.

This transient is initiated by a positive reactivity insertion caused by the introduction of cold water from the inactive loop into the reactor core. The results of the P121 analyses are documented in table 6.1

The Startup of an Inactive Loop event meets all acceptance criteria.

6.2.7 Feedwater System Malfunction

This transient was not run for P121 because the results from the P217 analysis bound this cycle.

The Feedwater System Malfunction transient is initiated by opening the #5 feedwater heater bypass valves. This results in colder feedwater entering the steam generator which increases the heat transfer from the primary to the secondary side. This, in turn, removes more heat from the RCS and T_{ave} decreases. The subsequent positive reactivity insertion from a negative MTC causes the power to increase. In addition, the rod control logic senses the reduction in T_{ave} and steps rods out in an attempt to get the RCS back to the programmed T_{ave}. The combination of negative MTC and the control system causes a power overshoot. The resulting DNB at these conditions is calculated in the analysis.

From the P217 analysis, the core power peaked at about 112.3% of full power and the minimum DNBR was 1.434 at 20 seconds.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.7-1 through 6.2.7-3.

The Feedwater System Malfunction transient meets all acceptance criteria.

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6.2.8 Excessive Load Increase

This transient was not run for P121 because the results from the P118 analysis bound this cycle.

The Excessive Load Increase transient is initiated by opening the turbine control valves to the full-open position, modeled as 120% of full power steam flow . The subsequent reduction in the steam generator shell side pressure causes more steam to be produced and, hence, more heat is removed from the RCS. This increases the ΔT across the core and consequently, lowers T_{ave}. This will insert positive reactivity from both a negative moderator temperature coefficient and the rod control logic which will withdraw rods in a attempt to raise T_{ave} to the programmed temperature. The result is an increase in reactor power and a consequent reduction in the margin to DNB.

From the analysis performed for P118, the core power peaked at about 114% of full power at 104 seconds and the minimum DNBR was 1.487 at 100 seconds.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.8-1 through 6.2.8-4.

The Excessive Load Increase transient meets all acceptance criteria.

6.2.9 Loss of External Load/Turbine Trip

This transient was not run for P121 because the results from the P218 analysis bound this reload.

This transient considers the plant response from full power when a loss of load results in a turbine trip. Normally, a turbine trip will directly cause a reactor trip, but for the sake of conservatism this direct trip is neglected in the analysis. This transient could be limiting on either high RCS pressure or DNB. Taking credit for the PORVs opening will reduce margin to DNB and at the same time increase margin to overpressure. Conversely, assuming the PORVs to remain closed will reduce margin to overpressure and increase margin to DNB. Consequently, both conditions were considered. The results from the P218 analysis are presented below.

Overpressure Limited Case: To reduce the margin to overpressure, all the RCS pressure control mechanisms were disabled including the PORVs and pressurizer spray. Although the safety valves were not disabled, their setpoints were set to the high end of their tolerance bands. In addition, the steam generator relief valves were disabled. Since a positive MTC was modeled, the reactor power increased after the turbine trip. The reactor tripped on overpressure 7.5 seconds after the turbine

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trip. The maximum RCS pressure was 2575 psia, and the maximum power was 105%. The steam generator pressure reached 1130 psia.

DNB Limited Case: To reduce the margin to DNB, all the RCS pressure control mechanisms were enabled. The PORVs were set to open at the low ends of their pressure setpoint tolerance bands and pressurizer spray was set to full flow. As in the overpressure limited case, the steam generator relief valves were disabled. Since a positive MTC was modeled, the reactor power increased after the turbine trip. The reactor tripped on OTΔT 10 seconds after the turbine trip. The maximum RCS pressure was 2350 psia, and the maximum power was 108%. The steam generator pressure reached 1166 psia. The minimum DNBR was 1.373, 17.0 seconds after the turbine trip.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.9-1 through 6.2.9-5.

The Loss of External Load/Turbine Trip transient satisfies all acceptance criteria.

6.2.10 Loss of Normal Feedwater Flow

The limiting analysis for this event was not performed during the P121 reload evaluation. The limiting analysis was based on the P119 reload utilizing conservative input assumptions. The results from the limiting analysis bound the P121 reload.

The Loss of Normal Feedwater Flow transient is essentially a loss of non-emergency AC power. A bounding analysis was performed based on conservative input assumptions using data from P119. The results of this analysis demonstrated the core power decreases from the initial condition. Therefore, minimum DNBR is not a concern for this transient. The maximum RCS pressure calculated was 2376 psia, and the maximum steam generator pressure achieved during the transient was 1125 psia.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.10-1 through 6.2.10-4.

The Loss of Normal Feedwater Flow transient satisfies all acceptance criteria.

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6.2.11 Loss of Reactor Coolant Flow/Pump Trip

This transient was not run for P121 because the results from the P218 analysis bound this reload.

The Loss of Reactor Coolant Flow/Pump Trip transient is initiated from full power by tripping one (1/2) or both (2/2) reactor coolant pumps and allowing them to coast down. The single failure is assumed to be the failure of a reactor protection train. However, the reactor protection system is assumed to operate as designed since no single failure will prevent proper operation of the protection system. The reactor trip on low reactor coolant flow is modeled explicitly using a conservative 1.2 second time delay between the time the flow condition is sensed and the reactor is actually tripped. The resulting reduction in core flow decreases DNBR and increases RCS pressure because T_{ave} increases. With a positive MTC, the core power also increases which aggravates both DNB and pressure. Note, however, that keeping the RCS pressure lower by enabling the pressure control systems will minimize margin to DNB while disabling them will minimize margin to overpressure. Thus, both cases are evaluated. The Locked Rotor transient bounds the 1/2 and 2/2 Pump Trip transients with respect to overpressure so the overpressure case is typically not analyzed for the 1/2 and 2/2 Pump Trip.

The bounding P218 analysis indicated the reactor tripped on low reactor coolant flow 2.0 seconds after both pumps were tripped. The maximum power was 105% and the maximum RCS pressure was 2280 psia. The minimum DNBR was 1.278, 4.6 seconds after the pumps tripped.

Since the Locked Rotor transient satisfies the pressure criteria and the 2/2 Pump Trip transient satisfies the DNBR criteria, all acceptance criteria are met for this transient.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.11-1 through 6.2.11-4.

6.2.12 Loss of Reactor Coolant Flow/Locked Rotor

This transient was run for P121 to incorporate the increase to 25% steam generator tube plugging into the analysis of record.

The Locked Rotor transient is initiated from full power by abruptly seizing one of the reactor coolant pump shafts. The resulting reduction in core flow decreases DNBR and increases RCS pressure because T_{ave} increases. With a positive MTC, the core power also increases which aggravates both DNB and pressure. It is clear that a positive MTC would produce more limiting results than a negative MTC. The reactor trip on low reactor coolant flow is modeled explicitly using a conservative 1.5

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second time delay between the time the flow condition is sensed and the reactor is actually tripped.

This transient could be limiting on either high RCS pressure or DNB. Taking credit for the PORVs opening will reduce margin to DNB and at the same time increase margin to overpressure. Conversely, assuming the PORVs remain closed will reduce margin to overpressure and increase margin to DNB. Consequently, both conditions should be considered. The results from the P121 analysis are presented below.

Pressure Limiting Case: The positive MTC caused the reactor power to increase after the rotor seizure. The reactor trip signal on low reactor coolant flow was generated 0.04 seconds after the rotor seizure. The maximum RCS pressure was 2575 psia at 3.3 seconds, and the maximum steam generator pressure was 1117 psia at 31 seconds. The peak clad temperature was 2371°F at 3.7 seconds.

DNB Limited Case: The positive MTC caused the reactor power to increase after the rotor seized. The reactor trip signal on low reactor coolant flow was generated 0.04 seconds after the rotor seizure. The maximum RCS pressure was 2364 psia at 3.7 seconds, and the maximum steam generator pressure was 1115 psia at 31 seconds. During this transient 15.54% of the pins exceeded the DNBR limit and are assumed failed.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.12-1 through 6.2.12-4.

The Locked Rotor transient meets all acceptance criteria.

6.2.13 Fuel Handling Accident

Safety Evaluation (SE) 50-475 documents the bounding analysis for the Fuel Handling Accident at Prairie Island. SE 50-475 addresses the issue of opening the Spent Fuel Pool (SFP) enclosure personal doors immediately following a fuel handling accident and its affect on the SFP Special Ventilation operability as required by the Technical Specifications. SE 50-475 utilizes the results from the previous analysis performed by Fluor-Daniel (Reference 4) to demonstrate the Fuel Handling Accident doses remained below 10CFR100 limits. The Flour-Daniel analysis, which can be cross referenced as Prairie Island calculation GEN-PI-0023, validated that the Fuel Handling Accident doses remained below 10CFR100 limits for Vantage+ fuel.

For P121, it was determined that the source term input to the Fluor-Daniel analysis would bound a cycle specific P121 source term. Since the Fluor-Daniel analysis satisfied the 10CFR100 off-site dose acceptance criteria

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for the fuel handling accident and the input source term bounds P121, this accident satisfies all acceptance criteria.

6.2.14 Main Steam Line Break

The Main Steam Line Break transient is evaluated as four separate events, including the Large Steam Line Break: Core Response, and Containment Pressure & Temperature Responses, and the Small Steam Line Break.

Large Steam Line Break: The bounding analysis was based on physics assumptions consistent with the stuck rod location producing the most limiting peaking factors at cold core conditions. The bounding large SLB analysis also takes credit for local core conditions at the time of the minimum DNBR including the local reactivity feedback from the high neutron flux in the vicinity of the stuck rod.

Because of the rapid depressurization of the secondary system, steam generators produce more steam which removes more heat from the RCS. The cooldown of the RCS along with a negative moderator temperature coefficient causes the reactor to overcome the assumed shutdown margin and return to power. The most limiting control rod is assumed to be fully withdrawn from the core. This assumption not only decreases the amount of shutdown margin but also produces an adverse core power distribution when the reactor returns to power. Note that the most limiting stuck rod is not necessarily the maximum worth rod. The most restrictive single failure for this transient is the failure of one train of safeguards equipment (one SI pump, one CS pump, and two FCUs).

The Analysis of Record is the P220 LMSLB Analysis using the new methods specified in NSPNAD-97002-PA, Rev. 1. The bounding large SLB analysis was performed with BAST removed. A concentration of 2500 ppm for BAST is used, consistent with the RWST. The Large Steam Line Break event is utilized in a Core Response, and Containment Pressure and Temperature Responses.

Core Response: The Core Response LMSLB accident is initiated from hot shutdown conditions by a double-ended guillotine break downstream of the flow restrictor with an area equal to that of the flow restrictor. The return to power along with reduced RCS pressure decreases DNBR to the point where fuel failures could occur. The reactor is shutdown by injecting boric acid solution at 2500 ppm via safety injection (SI).

For the bounding LMSLB Core Response analysis, the maximum power reached was 32% at 89.2 seconds. The minimum DNBR was 1.46 which meets the 1.45 DNBR limit.

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Containment Pressure Response: The LMSLB containment pressure analysis is utilized to confirm acceptability of the containment design pressure limit of 46 psig. The Containment Pressure Response LMSLB accident is initiated from hot shutdown conditions by a double-ended guillotine break downstream of the flow restrictor with an area equal to that of the flow restrictor.

The actuation of the containment spray system and the Fan Coil Units provide heat removal capability which consequently generates the containment pressure suppression. The containment spray system capacity is assumed to be minimized, and the FCU capability is assumed to be equal to only one FCU (or equivalently two @ 50%).

For the bounding LMSLB Containment Pressure Response analysis, the maximum containment pressure reached was 44.89 psig at 139.9 seconds.

Containment Temperature Response: The SLB containment temperature analysis is utilized to confirm acceptability of the Environment Qualifications (EQ) requirements inside containment. The Containment Temperature Response LMSLB accident is initiated from hot full power conditions by a steam line break downstream of the flow restrictor with a assumed break area just small enough to prevent liquid entrainment. Containment equipment capabilities assumed consistent with the Containment Pressure Response analysis.

For the bounding LMSLB Containment Temperature Response analysis, the maximum containment temperature reached was 342 °F at 120.3 seconds.

Small Steam Line Break: The small SLB was performed for P121. A setpoint methodology review has indicated the Low Pressurizer Pressure setpoint for the initiation of Safety Injection is likely to be reduced. Thus, a new safety analysis has been performed, dropping that setpoint from 1800.0 psia to 1700.0 psia. The small SLB continues to adhere to the methodology specified in Reference 10. BAST has been eliminated from the Small SLB analysis.

The small SLB transient is similar to the large SLB except that the initial break flow is assumed to be only 25% of normal rated steam versus the 620% assumed in the large SLB transient. The small SLB transient is intended to envelope a steam generator relief valve failure.

From the P220 analysis, an SI signal occurred on low pressurizer pressure about 106 seconds after the break. The cooldown of the RCS in this time was not large enough to cause the reactor to return to power. Consequently, there was no challenge to DNB limits.

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Selected DYNODE-P transient response parameters for the Large Main Steam Line Break are shown in Figures 6.2.14-1 through 6.2.14-6.

6.2.15 Control Rod Ejection

The Control Rod Ejection transient is initiated by the failure of a control rod drive housing resulting in the ejection of an RCCA and drive shaft. The subsequent rapid positive reactivity insertion together with an adverse core power distribution could lead to localized fuel rod damage. This transient is analyzed at HZP and HFP conditions.

HZP Case: This transient is considered at three different points in the cycle; BOC, MOC and EOC. This is necessary to account for different combinations of ejected rod worths, Doppler feedback and peaking factors that can occur at these different cycle points. This transient was not run for P121 at BOC or MOC. The results from the P218 analysis at BOC and the P119 analysis at MOC bound this reload. A new analysis of record has been performed for P121 at EOC because the previous analysis of record at this exposure point does not bound this reload. Table 6.1 presents the results from the bounding P218, P119, and P121 analyses. All results meet the acceptance criteria.

HFP Case: The HFP rod ejection was not run for P121 because the results of the P114 analysis bound this cycle. The results of the P114 analysis show that the pellet energy deposition was 186 cal/g and the maximum cladding temperature was 2668°F.

Selected DYNODE-P transient response parameters for this event are shown in Figures 6.2.15-1 through 6.2.15-6.

Thus, the control rod ejection transient satisfies all acceptance criteria.

6.2.16 Loss of Coolant Accident (LOCA)

The LOCA-ECCS analysis will be addressed under a separate cover. The information transmitted to Westinghouse for the confirmation is shown in Tables 6.4 and 6.5.

6.2.17 Fuel Misloading Accident

The Fuel Misloading accident assesses the consequences of the inadvertent loading and operation of a cycle with a fuel assembly in an improper location. At Prairie Island only the interchange of two assemblies is possible, since the fuel manipulation crane is only able to engage a fuel assembly in the correct orientation.

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According to the RSE Methods topical NSPNAD-8102-PA, Revision 7, the misloaded bundle accident need not be reanalyzed each cycle since the incore moveable detector system was shown to be able to detect any misloadings of consequence.

6.3 *Exposure Limits*

The offsite dose calculations done by Fluor-Daniel for Prairie Island in 1995 are valid for core average exposures less than 50,000 MWd/MTU and maximum assembly exposures less than 75,000 MWd/MTU. Refer to References 4 and 6 for more details.

The EOC exposures for this cycle are presented in Table 4.2 and are less than the limits quoted above. It should be noted that all fuel assemblies loaded for Prairie Island have a maximum pin exposure limit which is less than the maximum assembly exposure assumed in the Fluor-Daniel analysis. The exposure limits for this cycle are presented in Table 4.2.

6.4 *Shutdown Margin Requirements*

The P121 Shutdown Margin Requirements for Modes 3 – 6 are based upon the Uncontrolled Boron Dilution event from an initial subcritical condition from Section 6.2.5. The basis for the SDM requirements for Modes 1 & 2 is to ensure meeting the Mode 3 ($T_{ave} \geq 520°F$) SDM requirement following a reactor trip from Modes 1 or 2. Table 6.6 summarizes the shutdown margin requirements for PINGP Unit 1 Cycle 21.

6.5 *Impact of the Extended Burnup Assembly, T81, on Safety Analyses*

The potential impact of the Extended Burnup Assembly on the Chapter 14 transients documented in Section 6.2 has been assessed as part of this RSE. All design criteria have been satisfied. The impact of T81 on the PI Unit 1 Cycle 21 core has been determined to be minimal and resulted in no fundamental changes in the safety analyses performed as part of this RSE. Operation of this fuel assembly to extended burnups (75,000 MWd/MTU) will not increase the probability of occurrence or consequences of any postulated accidents.

Several key parameter of the Chapter 14 transients were evaluated to confirm the impact of the extended burnup assembly is not significant. T81 was analyzed to insure that there would not be any increase in the likelihood of fuel rod failures in Condition II transients. It was confirmed

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that the requirement of no fuel failures for Condition II transients is met with T81 in the core. The fuel rods of the extended burnup assembly were checked to insure that they are not in the highest fuel rod power density locations in the core. The assembly operates near 80% of the core average power throughout the cycle, confirming that fuel rods in T81 are not in the highest fuel rod power density locations in the core. Shutdown Margin (SDM) in a N-2 rod configuration (the N-1 high worth control rod and the control rod inserted into the extended burnup assembly, G7, stuck out) was analyzed to address the potential impact of T81 on incomplete rod insertion (IRI). It was confirmed that even with the G7 rod withdrawn in addition to the N-1 rod, the minimum Shutdown Margin Requirement of 2%, documented in Section 6.4, is met. Fuel centerline melt for T81 during the dropped rod transient was confirmed to meet the requirements of Section 6.2.1, item k.

Three of the Chapter 14 transients were identified to be potentially impacted by the inclusion of the extended burnup assembly, Locked Rotor, Main Steam Line Break (MSLB), and Rod Ejection. Evaluation of these events has determined that the extended burnup assembly is not limiting and has no significant impact on these transients.

The primary impact of T81 on the Locked Rotor event is the potential impact of fuel pin failures in this assembly on meeting the 20% fuel failure limit for this event. Based on the bounding AOR, it was determined that even if all fuel pins in T81 were to fail, this event would not exceed the 20% fuel failure limit.

For MSLB, it was determined that even with T81 in the core, no fuel failures are predicted to occur as a consequence of this accident. Calculated doses are based on failures that exist at the time of the accident. It was further determined that Technical Specification Limits on dose equivalent iodine-131 limit the primary coolant activity and assure that the existing analysis remains bounding, even if some of the T81 rods were to fail.

Two areas of primary impact for the T81 assembly on the Rod Ejection transient were identified, the potential for this event to exceed the 20% fuel pin failure limit (if all the T81 fuel pins fail in addition to those predicted to fail in the AOR) and the potential impact of a Rod Ejection transient centered on the rodded T81 bundle. Based on the bounding AOR, it was determined that even if all fuel pins in T81 were to fail, this event would not exceed the 20% fuel failure limit. Due to the low rod worth of the T81 rod, $0.31, it was determined that a T81 rod ejection would not likely result in any fuel failures.

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Table 6.1

Summary of Transient Results

The results in the table are presented as "Calculated Value/Acceptance Criteria" pairs.
"-" means that the parameter is not calculated, is not relevant to this report, or is not an acceptance criteria for the event

Transient	Min DNBR	RCS Press [psia]	MSL Press [psia]	Failed Pins [%]	Clad Temp [°F]	Fuel Enthalpy [cal/g]
Rod Withdrawal – Subcritical	*	-	-	-	-	-
Rod Withdrawal – at Power	1.180/1.17	2581/2750	1184/1210	-	-	-
Control Rod Misalignment	1.201/1.17	-	-	-	-	-
Dropped Rod	1.277/1.17	2250/2750	725/1210	-	-	-
Start-up of an Inactive Loop	3.047/1.17	2430/2750	1065/1210	-	-	-
Feedwater System Malfunction	1.434/1.17	2227/2750	763/1210	-	-	-
Excessive Load Increase	1.487/1.17	2220/2750	751/1210	-	-	-
Loss of Load/Turbine Trip	1.373/1.17	2575/2750	1166/1210	-	-	-
Loss of Normal Feedwater	-	2376/2750	1125/1210	-	-	-
Loss of Flow - 2/2 RCP Trip	1.278/1.17	2280/2750	981/1210	-	-	-
Loss of Flow - Locked Rotor	-	2575/2750	1117/1210	15.5/20.0	2371/2750	160/280
Large Steam Line Break	1.46/1.45	2250/2750	1040/1210	-	-	-
Ejected Rod						
HZP - BOC	-	2502/3000	-	-	2703/2750	155/280
HZP - MOC	-	2449/3000	-	-	2507/2750	146/280
HZP - EOC	-	2419/3000	-	8.4/20.0	2597/2750	207/280
HFP	-	2411/3000	-	-	2668/2750	186/280

* The MDNBR is not analyzed due to the non-limiting nature of the event.

Table 6.2

Nominal Initial Conditions for HFP*

Parameter	Nominal Value
Reactor Coolant System	
Total Core Heat Output, MW (102%)	1683
Heat Generated in Fuel, %	97.4
System Pressure, psia	2250
Reactor Inlet Temperature, °F	534.5
Total Coolant Flow, lb/hr	68.67×10^6
Effective Core Flow, lb/hr	64.50×10^6
Hot Channel Factors	
Total Peaking Factor, F_Q	2.40
Enthalpy Rise Factor, $F_{\Delta H}$	1.77
P-bar	1.59
Steam Generators	
Calculated Total Steam Flow, lb/hr	7.33×10^6
Steam Temperature, °F	506.2
Feedwater Temperature, °F	434.6
Tubes Plugged, %	25.0

* All the parameters are changed appropriately for each transient to maximize the consequences of the transient.

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Table 6.3

Setpoints and Delay Times Used in the Transient Analysis

Trip Function	Technical Specification Setpoint	Setpoint Used in Analysis	Delay Time Used in Analysis
High Neutron Flux (High Setting)	≤ 108%	118%	≥ 0.45 sec
(Low Setting)	≤ 40%	50%	≥ 0.45 sec
Low Reactor Coolant Flow	90%	87%	≥ 1.20 sec
High Pressurizer Pressure	≤ 2400 psia	2425 psia	≥ 1.00 sec
Low Pressurizer Pressure	≥ 1830 psia	1700 psia	≥ 1.00 sec
High Pressurizer Water Level	≤ 90% of Span NR	100% of Span	≥ 1.50 sec
Low-Low Steam Generator Water Level	≥ 5% of Span NR	0% of Span	≥ 1.50 sec
Overtemperature OTΔT*	$T_{o\,ave}$ = 567.3°F P_o = 2250 psia	$T_{o\,ave}$ = 567.3°F P_o = 2250 psia	≥ 6.00 sec
Overpower OPΔT**	$T_{o\,ave}$ = 567.3°F	$T_{o\,ave}$ = 567.3°F	≥ 6.00 sec
High Pressure Safety Injection	≥ 1830 psia	1700 psia	≥ 10.0 sec
Negative Neutron Flux Rate	≤ 7% / 2 sec	10% / 2 sec	≥ 0.50 sec

* The overtemperature trip (OTΔT) is a function of pressurizer pressure, coolant average temperature, and axial offset. The $T_{o\,ave}$ and P_o setpoints are contained within the functional relationship.

** The overpower trip (OPΔT) is a function of coolant average temperature and axial offset. The $T_{o\,ave}$ setpoint is contained within the functional relationship.

Table 6.4

Prairie Island Unit 1 Cycle 21
LOCA/ECCS and Mechanical Analysis - Characteristics

Characteristic	Value
Nuclear Power	1650 MW_{th}
System Pressure	2250 psia
T_{in} at HFP	530.5 °F
T_{in} at HZP	547.0 °F
T_{ave} at HFP	560.0 °F
Core Average Linear Heat Generation Rate	6.18* kw/ft
LBLOCA Peak Linear Heat Generation Rate	14.23* kw/ft
Number of Reconstituted Fuel Pins in core	0 pins
Axial offset control strategy	Transient Power Distribution (NSPNAD-93003-A, Rev. 0)
Axial Offset Operational range	-11% to +13%
RWST minimum boron concentration (Tech Spec Limit)	2500 ppm
RWST low-low alarm setpoint	8%
Spray Additive Tank Maximum Volume (Caustic Addition Standpipe)	2630 Gal

* Includes the fraction of heat generated in the fuel = 0.974.

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Table 6.5

Prairie Island Unit 1 Cycle 21
LOCA/ECCS and Mechanical Analysis – Physics Parameters

Parameter		Value
Critical Boron		
HFP, ARO, Peak Xenon		1195 ppm at BOC
Cold, ARO, No Xenon		2096 ppm at BOC
Maximum Assembly Average Power During Depletion i.e., maximum P-bar (includes safety $RF_{F\Delta H}$)		
HFP, ARO, Eq. Xenon		1.51 at 12 GWd/MTU
Maximum Pin Exposure for W Fuel		59.32 GWd/MTU(1) 72.72 GWd/MTU(1)
Gadolinia Rod Data		
Gd_2O_3 Loadings		576 pins @ 8 $^w/_o$ Gd_2O_3
U^{235} Enrichments		2.97$^w/_o$ U^{235} (8$^w/_o$ Gd_2O_3)
Maximum F_Q during depletion [(Pin Power)^{MAX}*F_Z*V(z)+RF+Bias]		1.79
Delayed Neutron Fraction ±10%	Maximum	0.006696 at BOC
	Minimum	0.004492 at EOC

Notes

(1) The 72.72 GWd/MTU exposure is the peak pin in center bundle T81, the test assembly which is burned beyond the Westinghouse license limit of 62 GWd/MTU. The 59.32 GWd/MTU exposure is the peak pin for the remainder of the core, burned within Westinghouse license limits.

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Table 6.6
P121 Shutdown Margin Requirements

Plant Conditions	Number of Charging Pumps Running		
	0-1 Pump	2 Pumps	3 Pumps
Mode 1	2.0	2.0	2.0
Mode 2	2.0	2.0	2.0
Mode 3, $T_{ave} \geq 520°F$	2.0	2.0	2.0
Mode 3, $350°F \leq T_{ave} < 520°F$	2.0	2.0	2.5
Mode 4	2.5	5.0	8.0
Mode 5	2.5	5.0	8.0
Mode 6, ARI	5.26	5.26	8.0
Mode 6, ARO	5.26	6.0	9.5

Operational Mode Definitions, as per TS Table 1-1.

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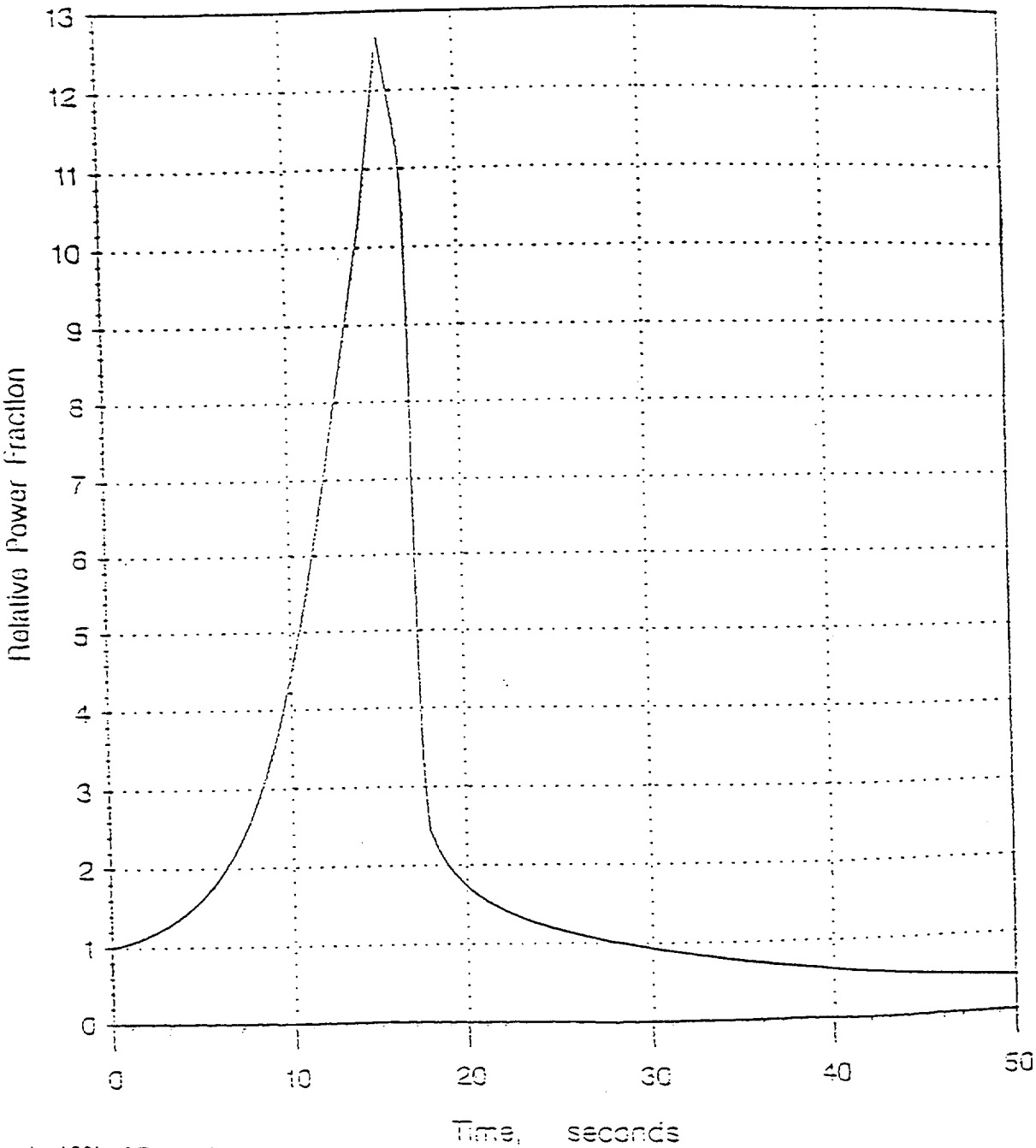
Figure 6.2.2-1

Prairie Island Safety Analyses

Fast Uncontrolled RCCA Withdrawal at Power



Relative to 10% of Rated Power

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Figure 6.2.2-2

Prairie Island Safety Analyses

Fast Uncontrolled RCCA Withdrawal at Power

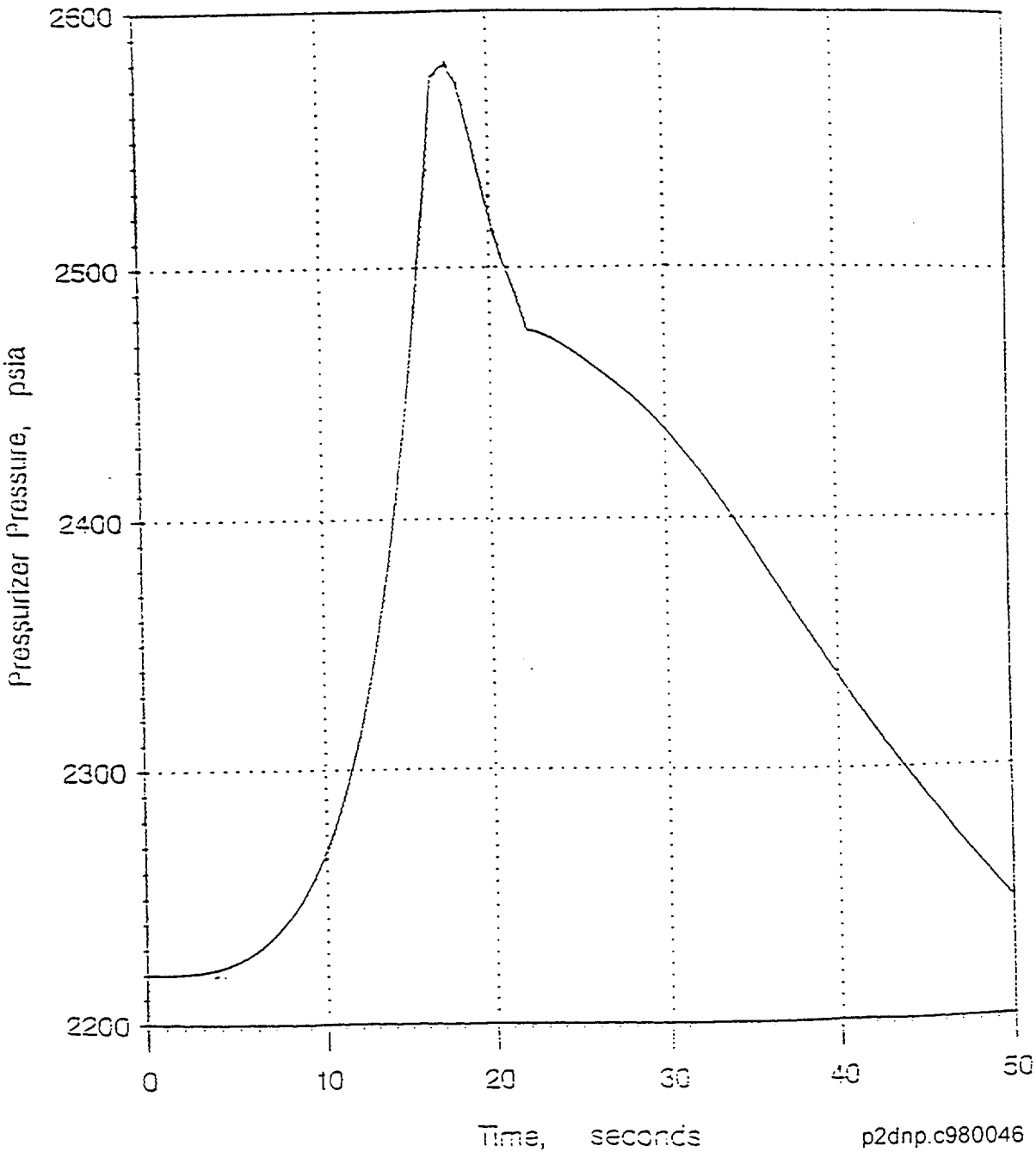

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Figure 6.2.2-3

Prairie Island Safety Analyses

Fast Uncontrolled RCCA Withdrawal at Power

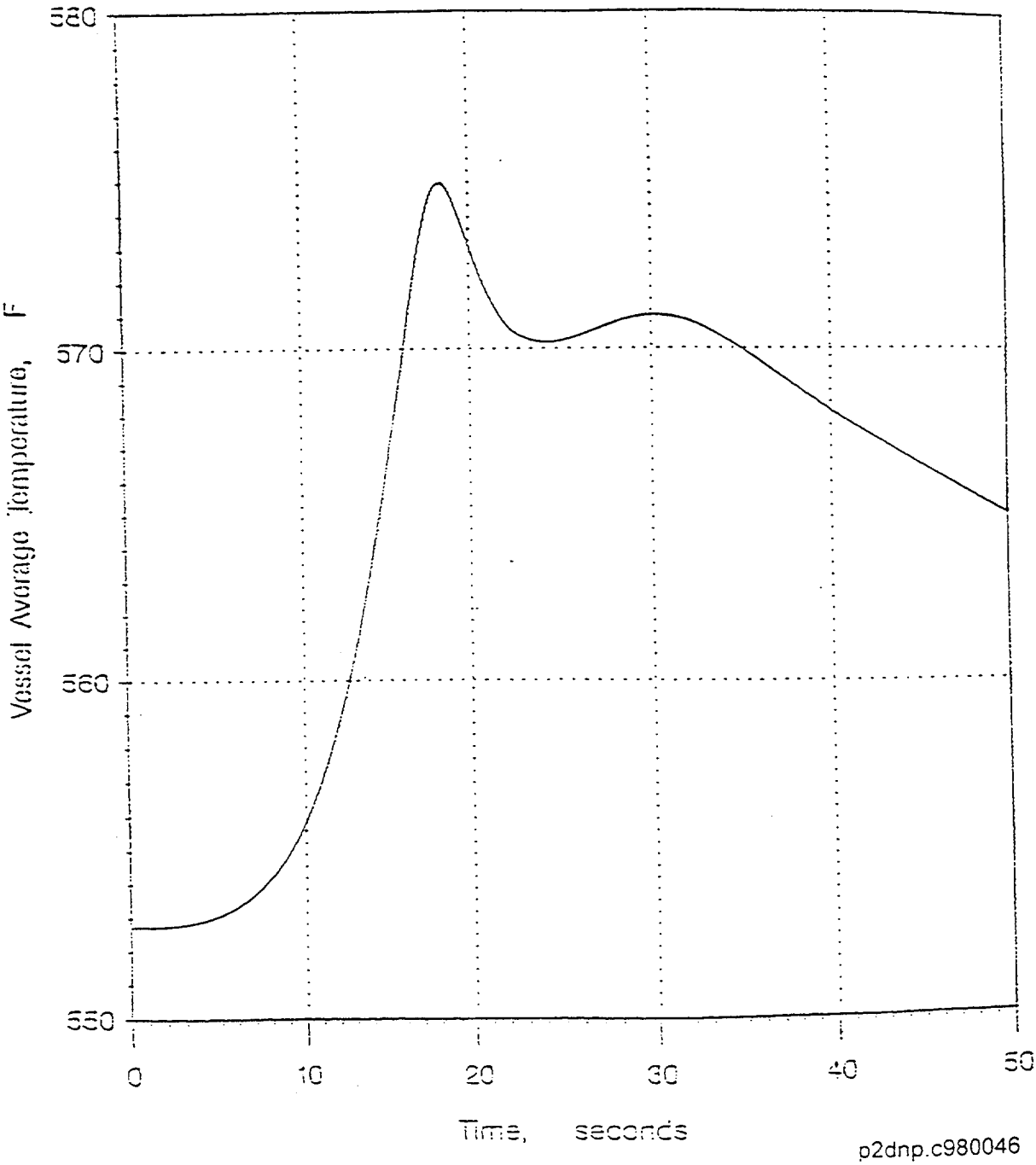

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Figure 6.2.2-4

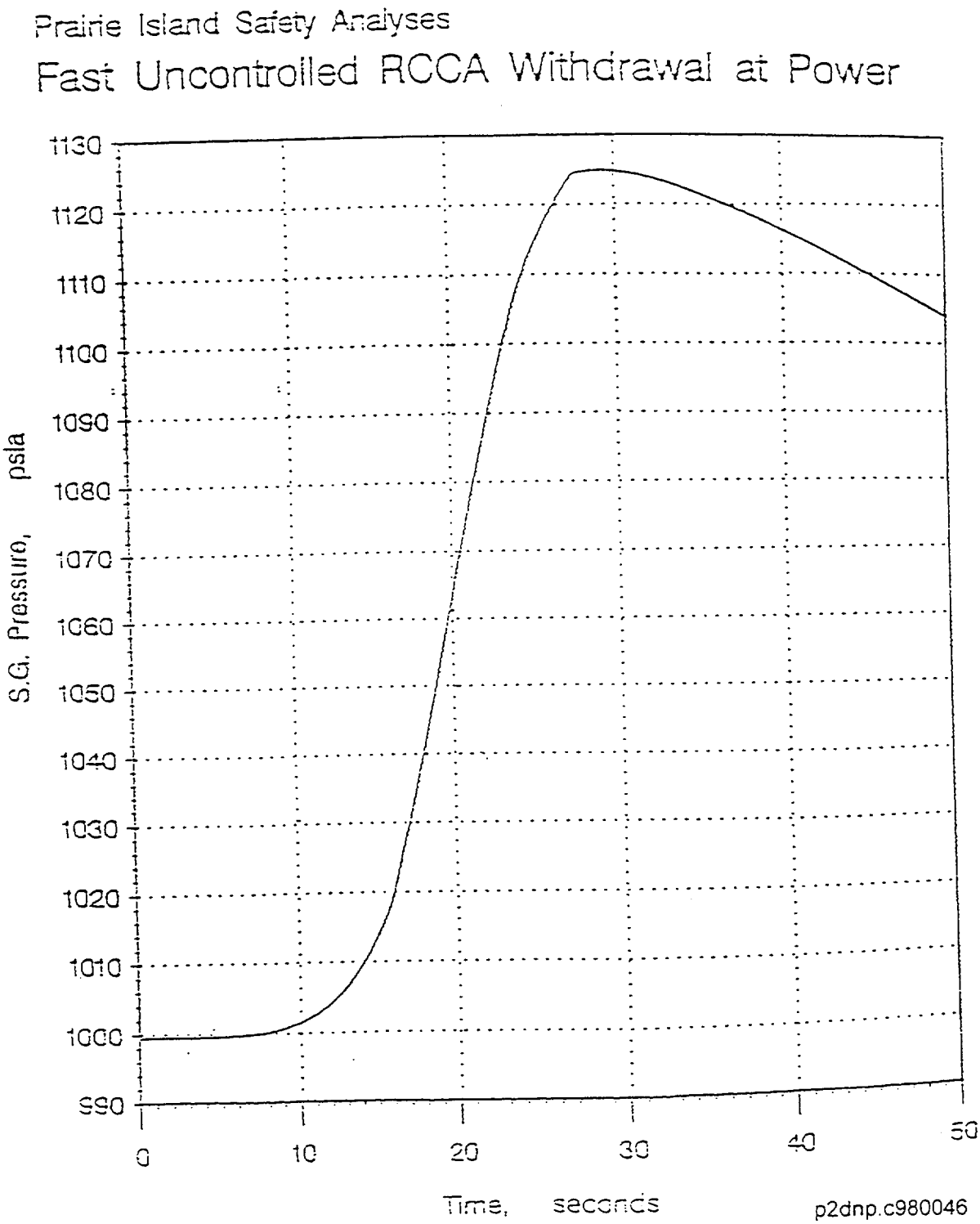

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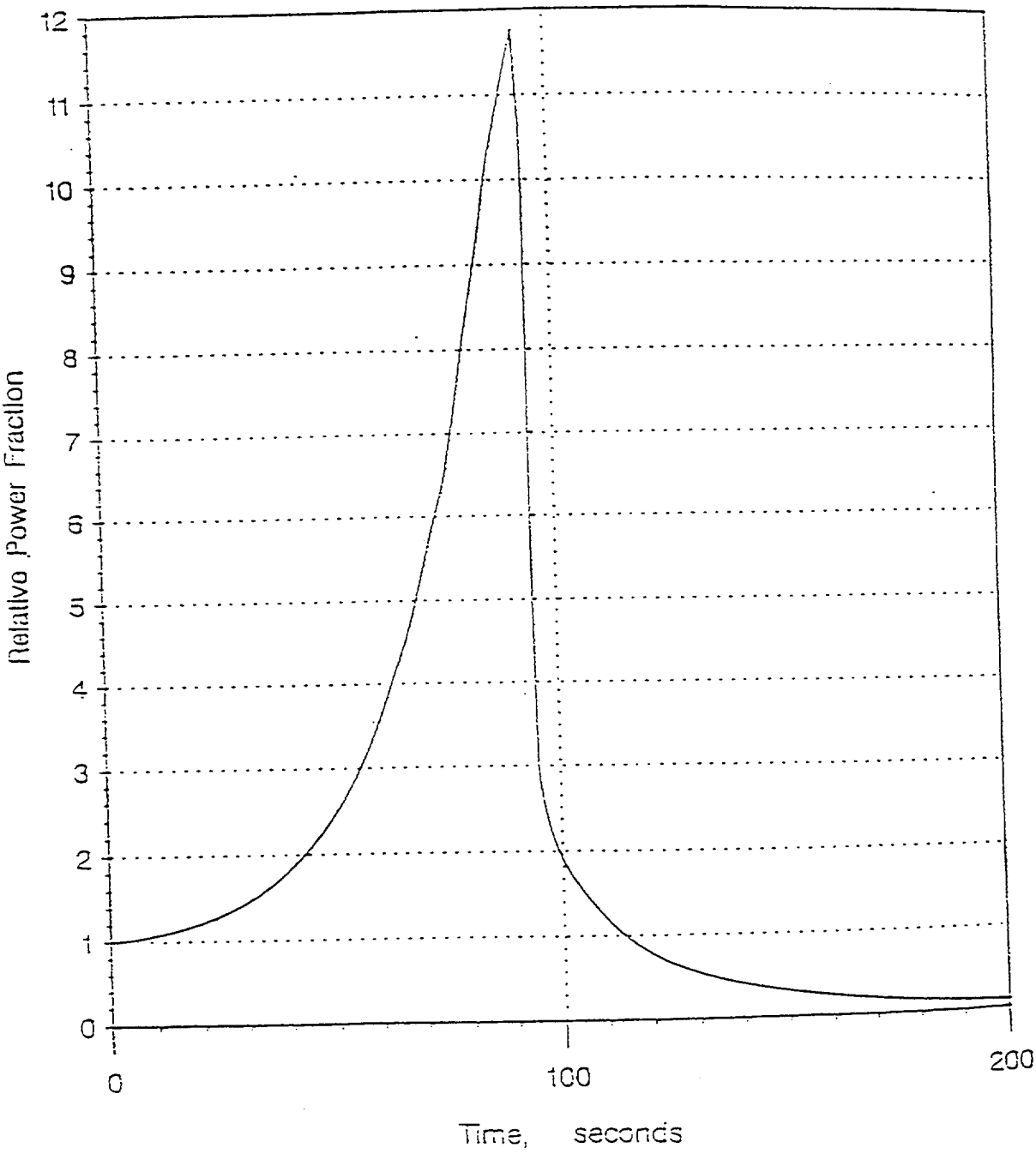
Figure 6.2.2-5

Prairie Island Safety Analyses

Slow Uncontrolled RCCA Withdrawal at Power



Relative to 10% of Rated Power

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Figure 6.2 2-6

Prairie Island Safety Analyses

Slow Uncontrolled RCCA Withdrawal at Power

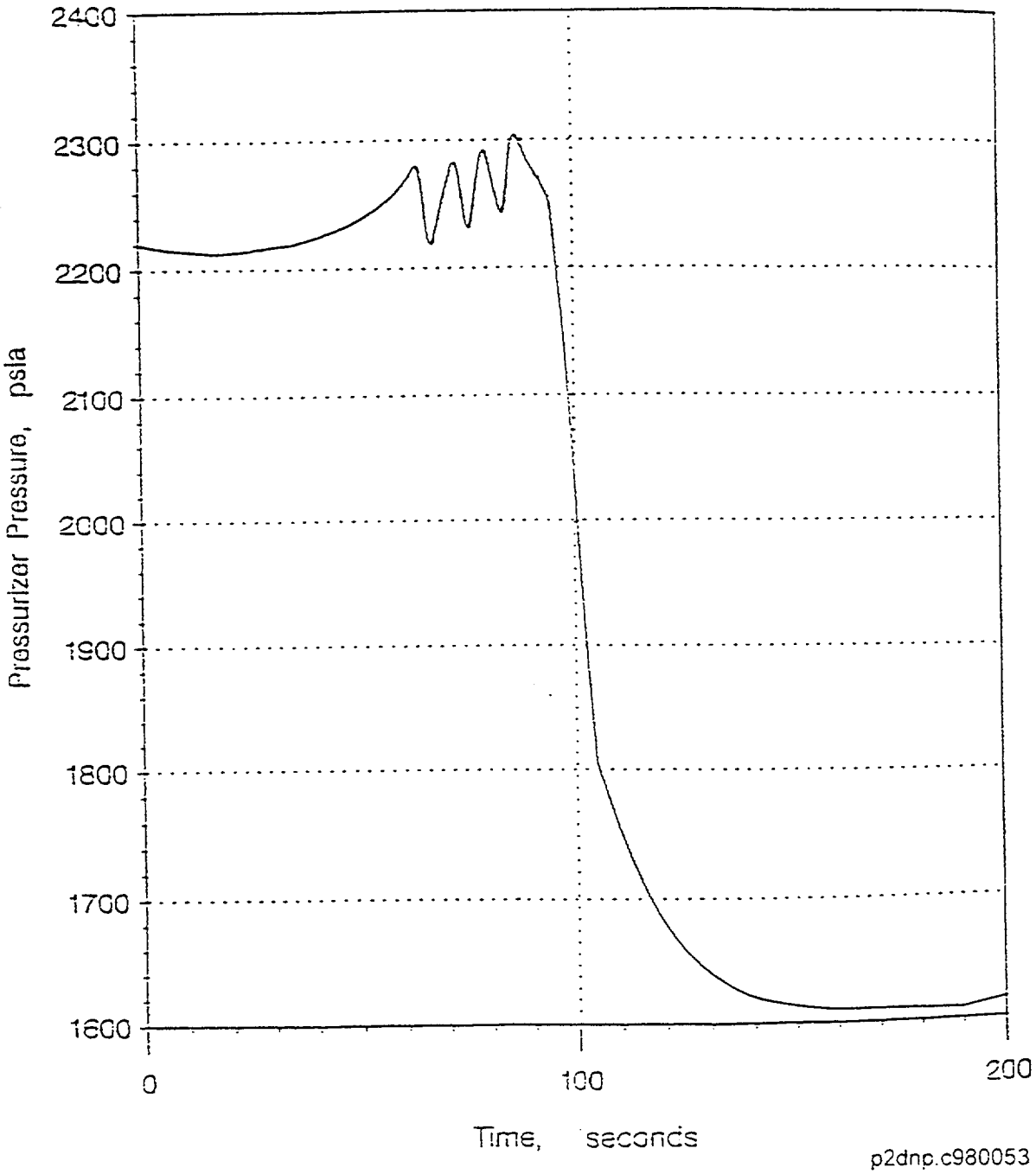

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Figure 6.2.2-7

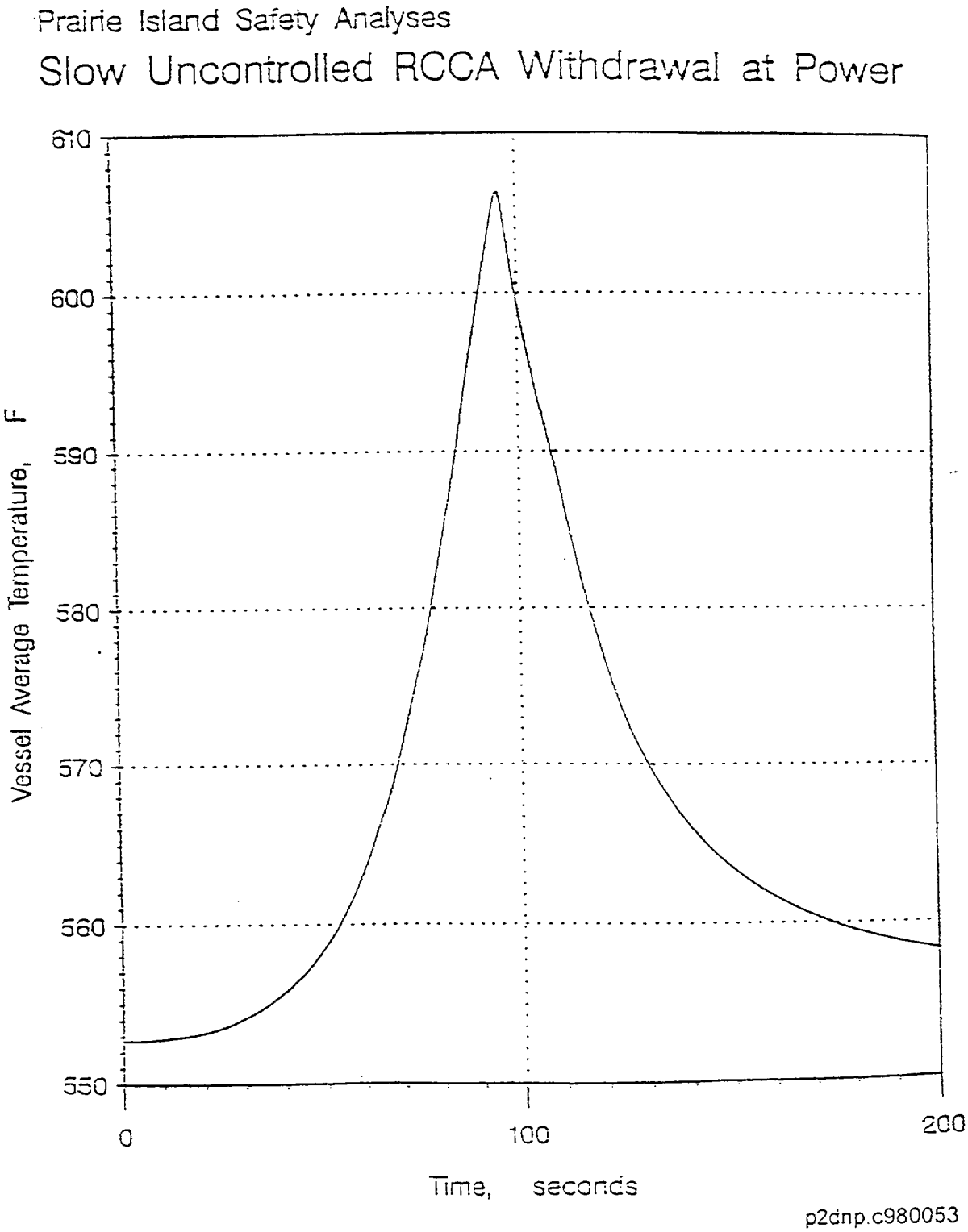

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Figure 6.2.2-8

Prairie Island Safety Analyses

Slow Uncontrolled RCCA Withdrawal at Power

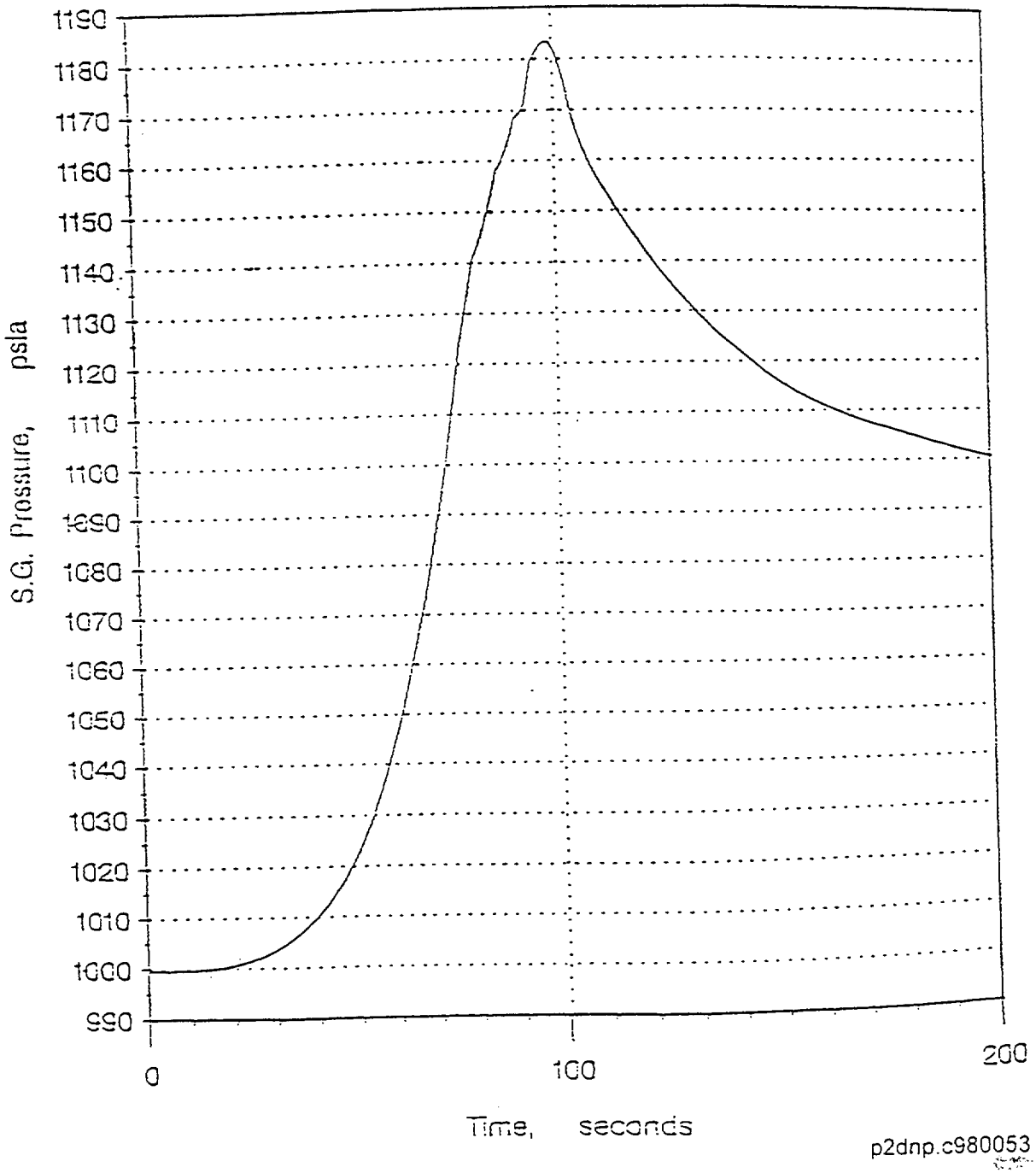

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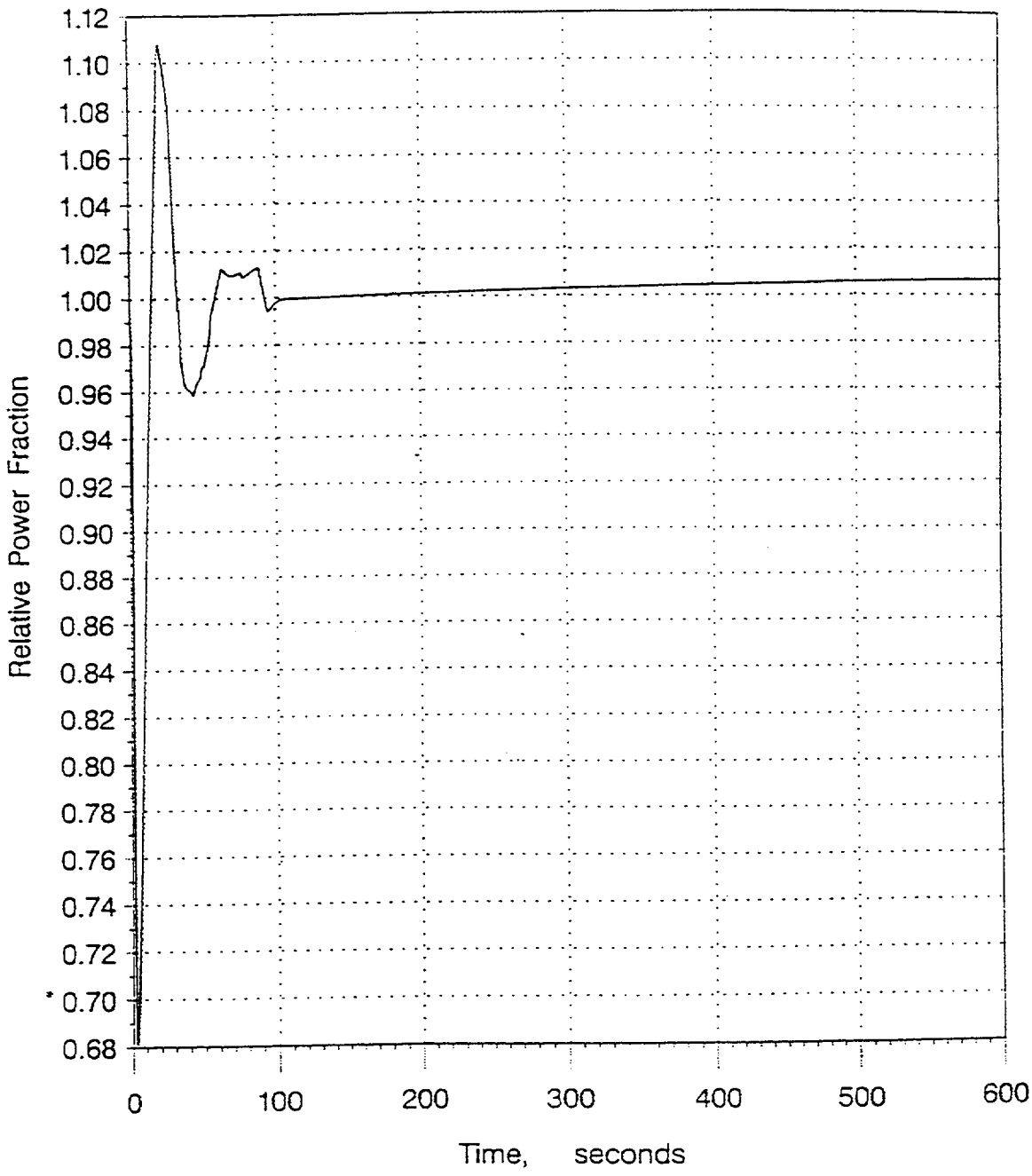
Figure 6.2.4-1

Prairie Island Safety Analyses

Dropped Rod



Relative to 102% of Rated Power

p1dnpc000025

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Figure 6.2.4-2

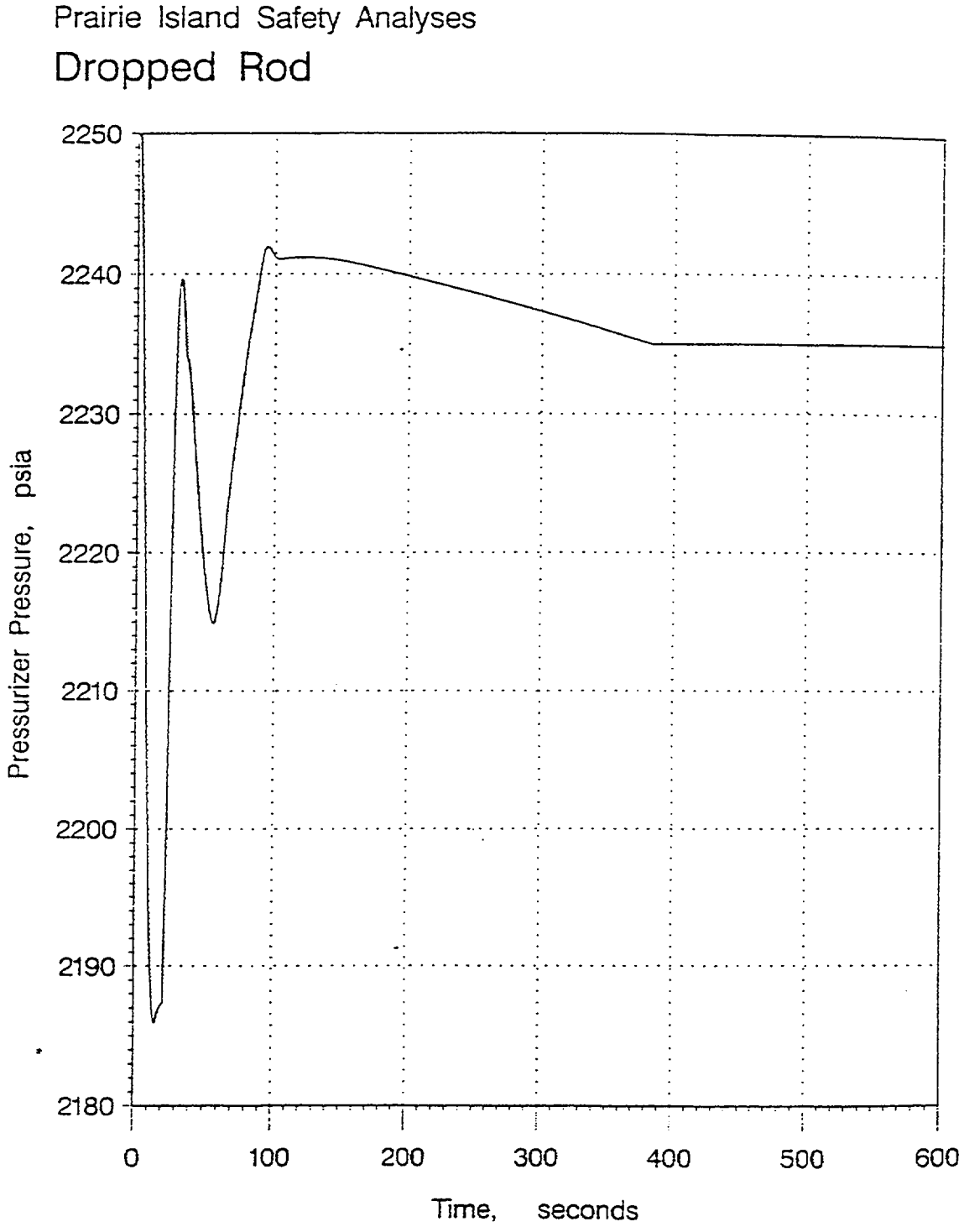

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Figure 6.2.4-3

Prairie Island Safety Analyses

Dropped Rod

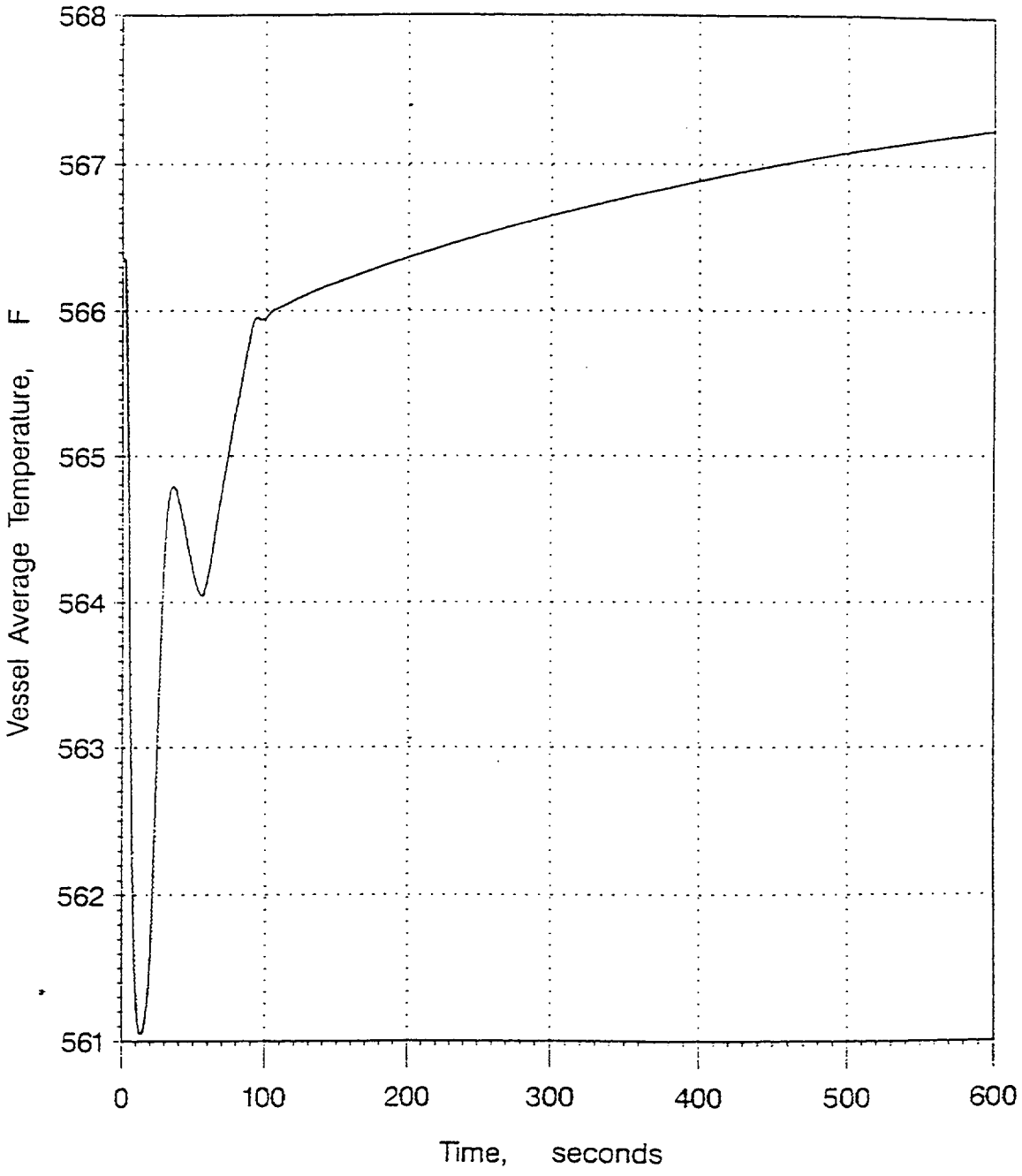

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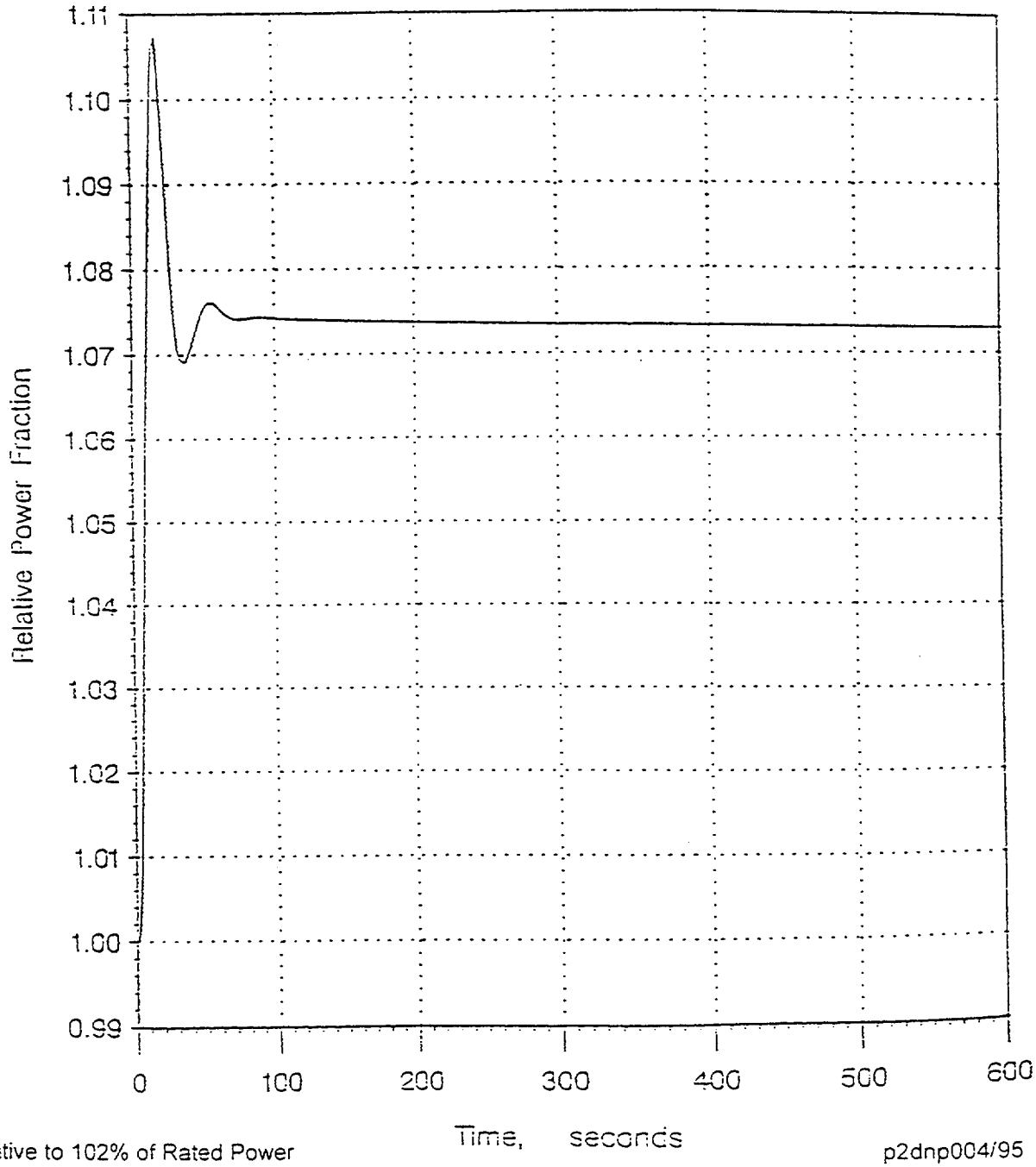
Figure 6.2.7-1

Prairie Island Safety Analyses

Feedwater System Malfunction With Reactor Control



Relative to 102% of Rated Power

p2dnp004/95

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Figure 6.2.7-2

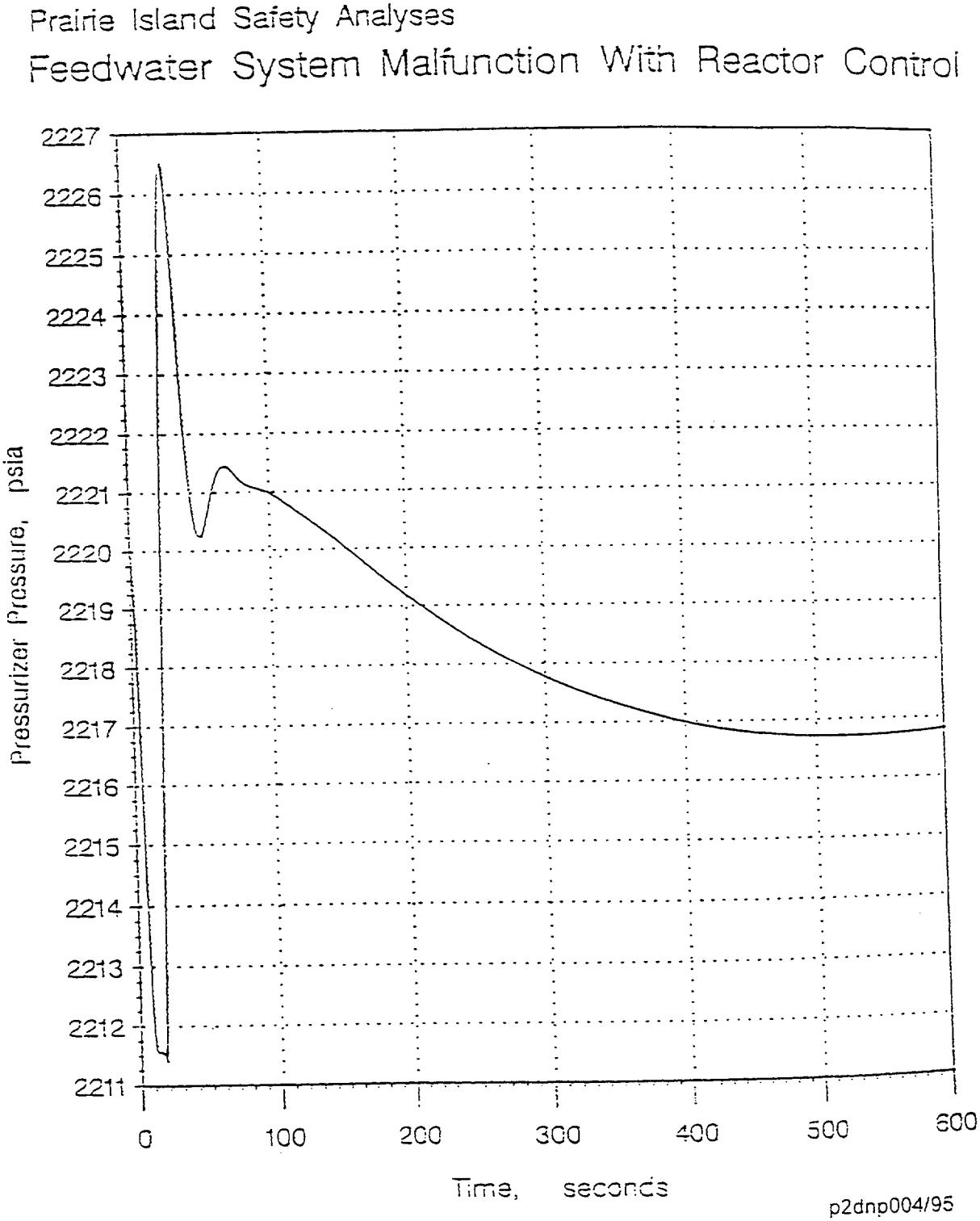

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Figure 6.2.7-3

Prairie Island Safety Analyses

Feedwater System Malfunction With Reactor Control

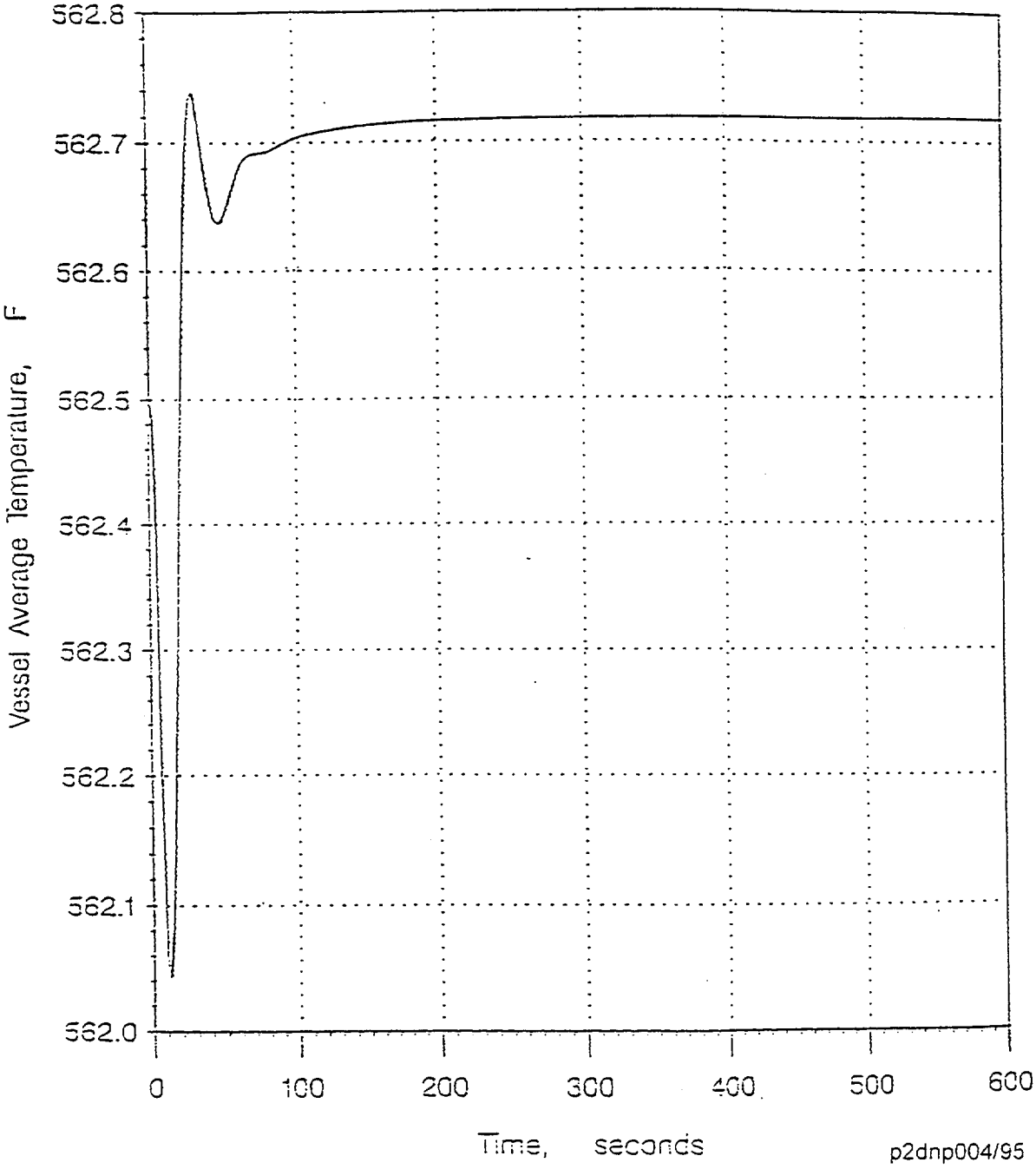

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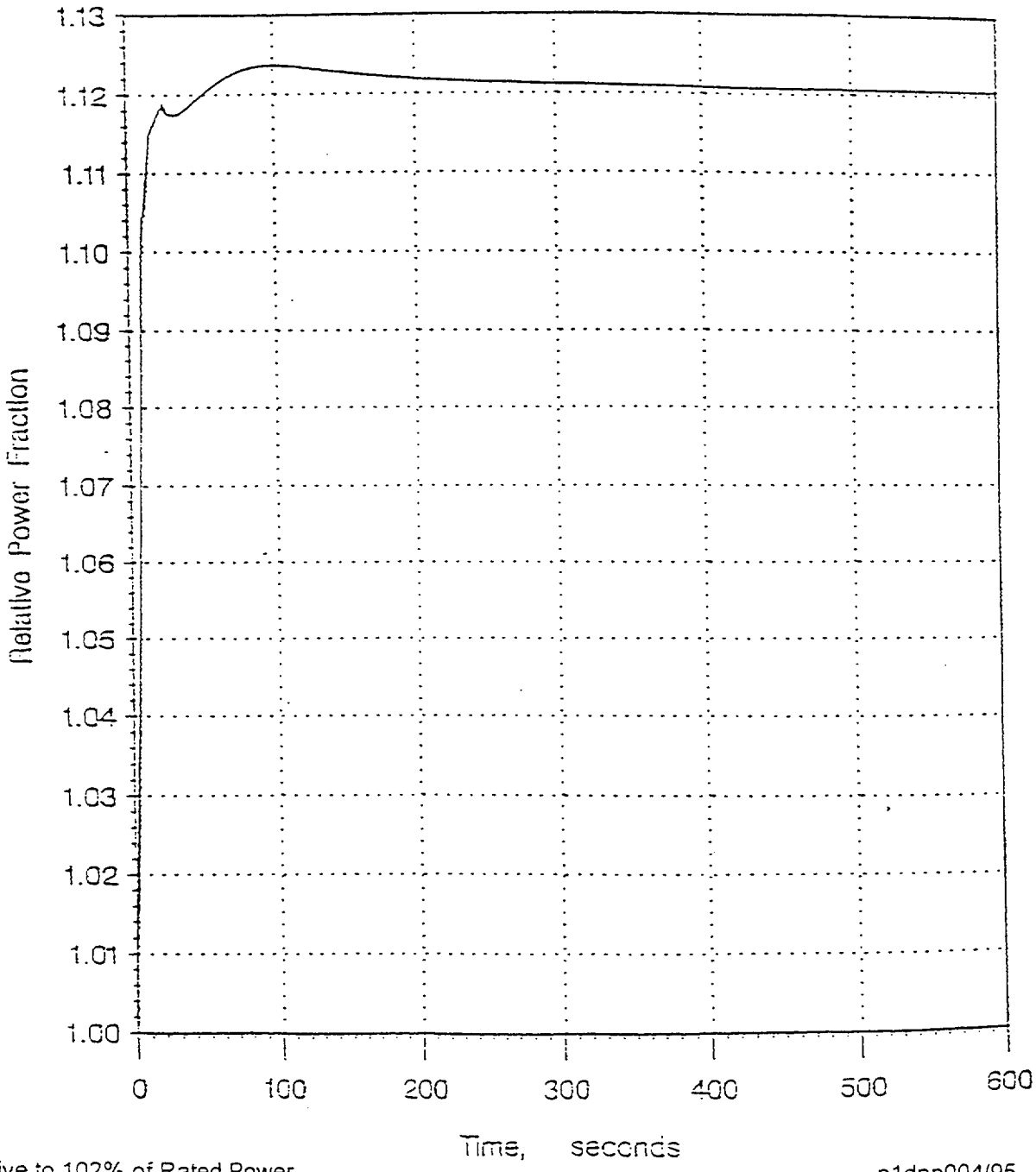
Figure 6.2.8-1

Prairie Island Safety Analyses

Excessive Load Increase/EOC With Reactor Control



Relative to 102% of Rated Power

p1dnp004/95

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Figure 6.2.8-2

Prairie Island Safety Analyses

Excessive Load Increase/EOC With Reactor Control

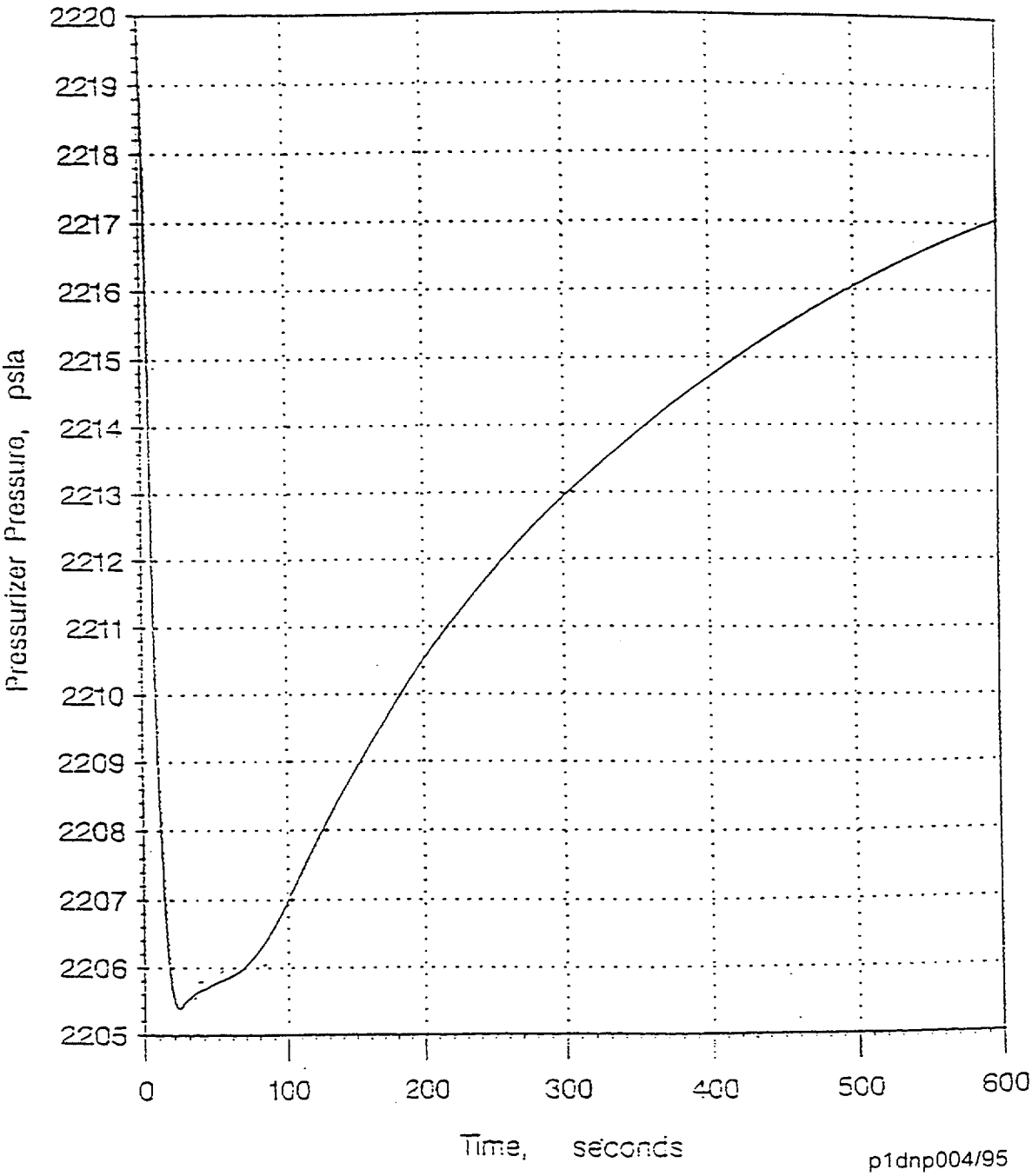

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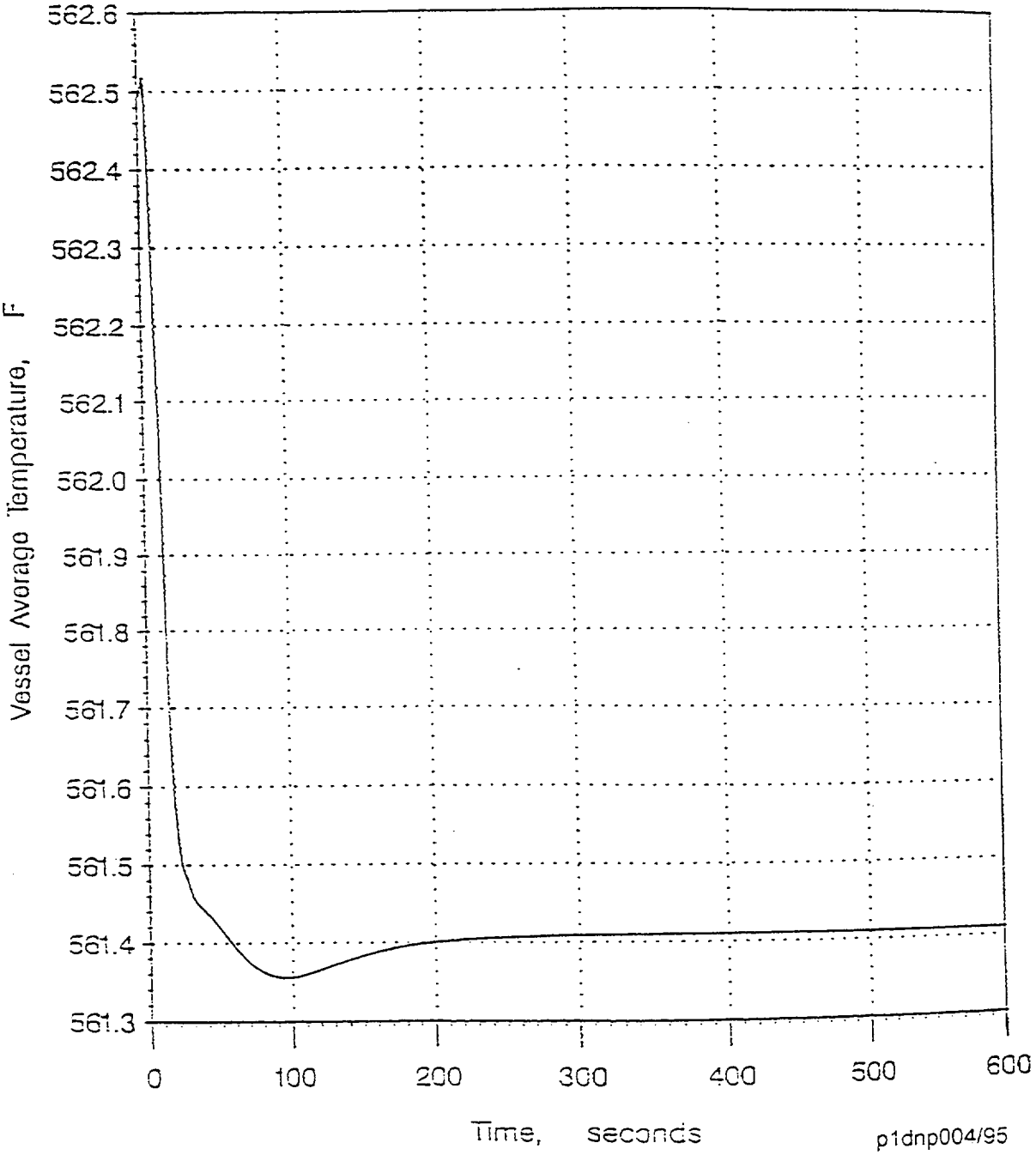
Figure 6.2.8-3

Prairie Island Safety Analyses

Excessive Load Increase/EOC With Reactor Control



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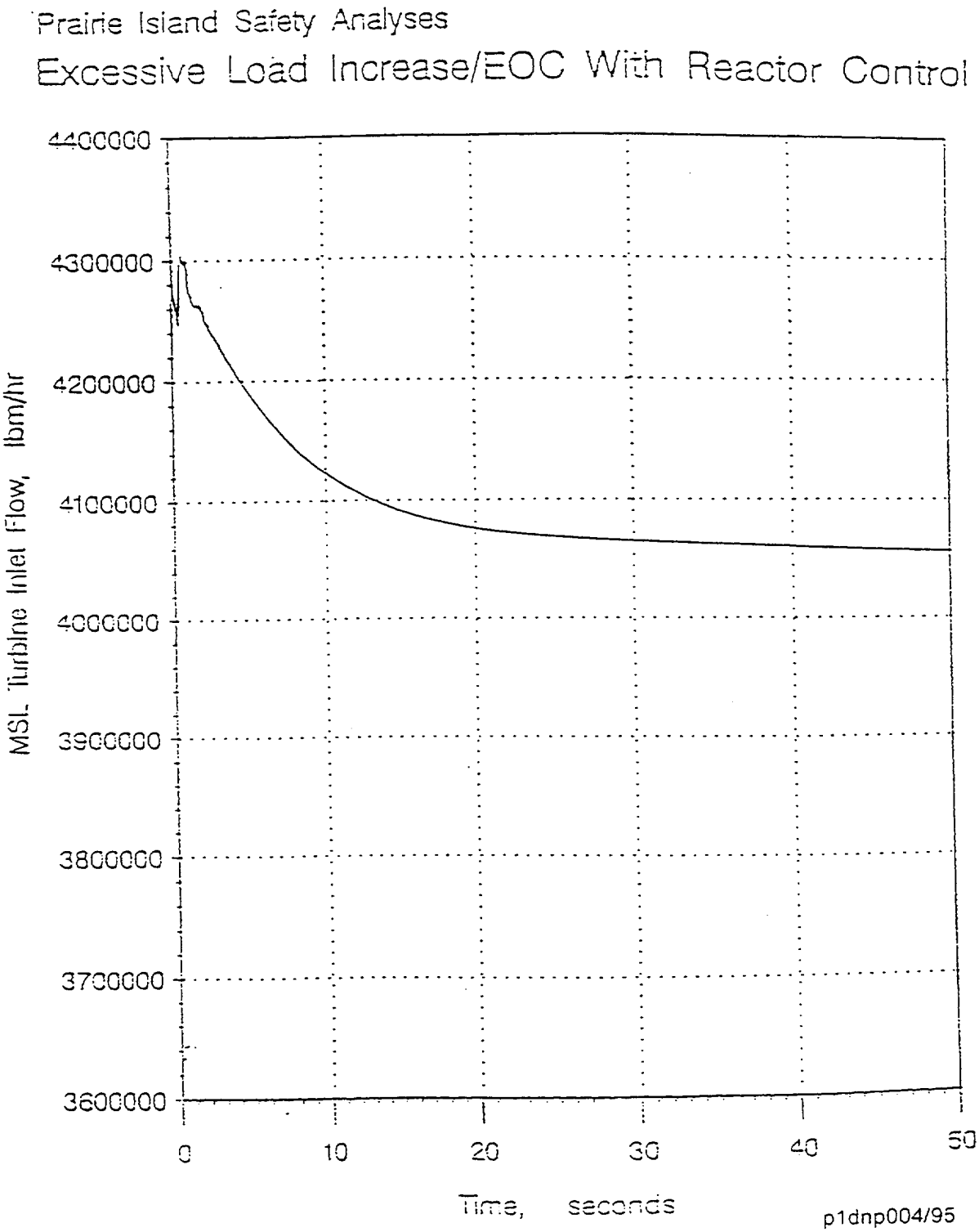

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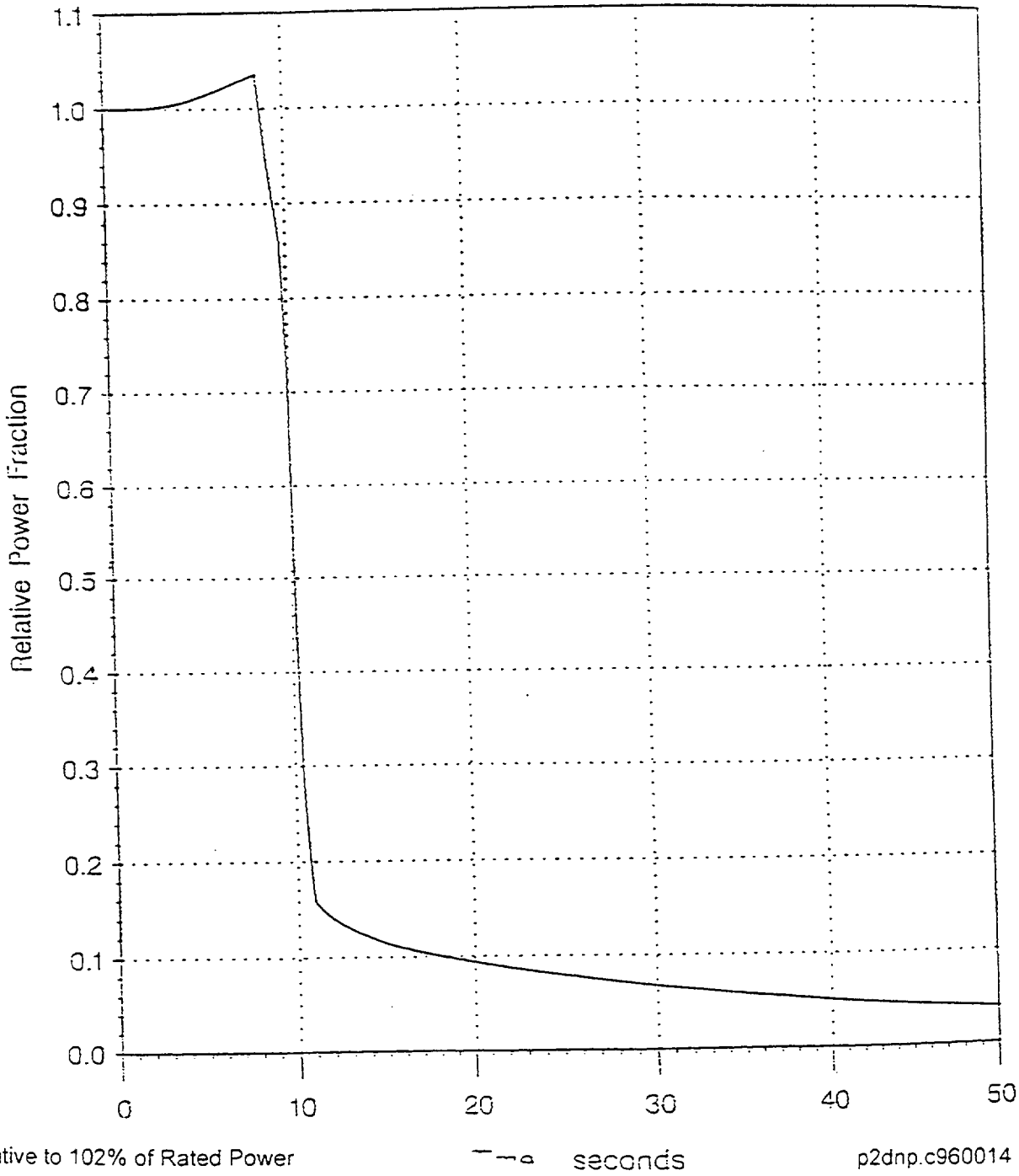
Figure 6.2.9-1

Prairie Island Safety Analyses

Loss of External Load/Turbine Trip



Relative to 102% of Rated Power

p2dnp.c960014

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Figure 6.2.9-2

Prairie Island Safety Analyses

Loss of External Load/Turbine Trip

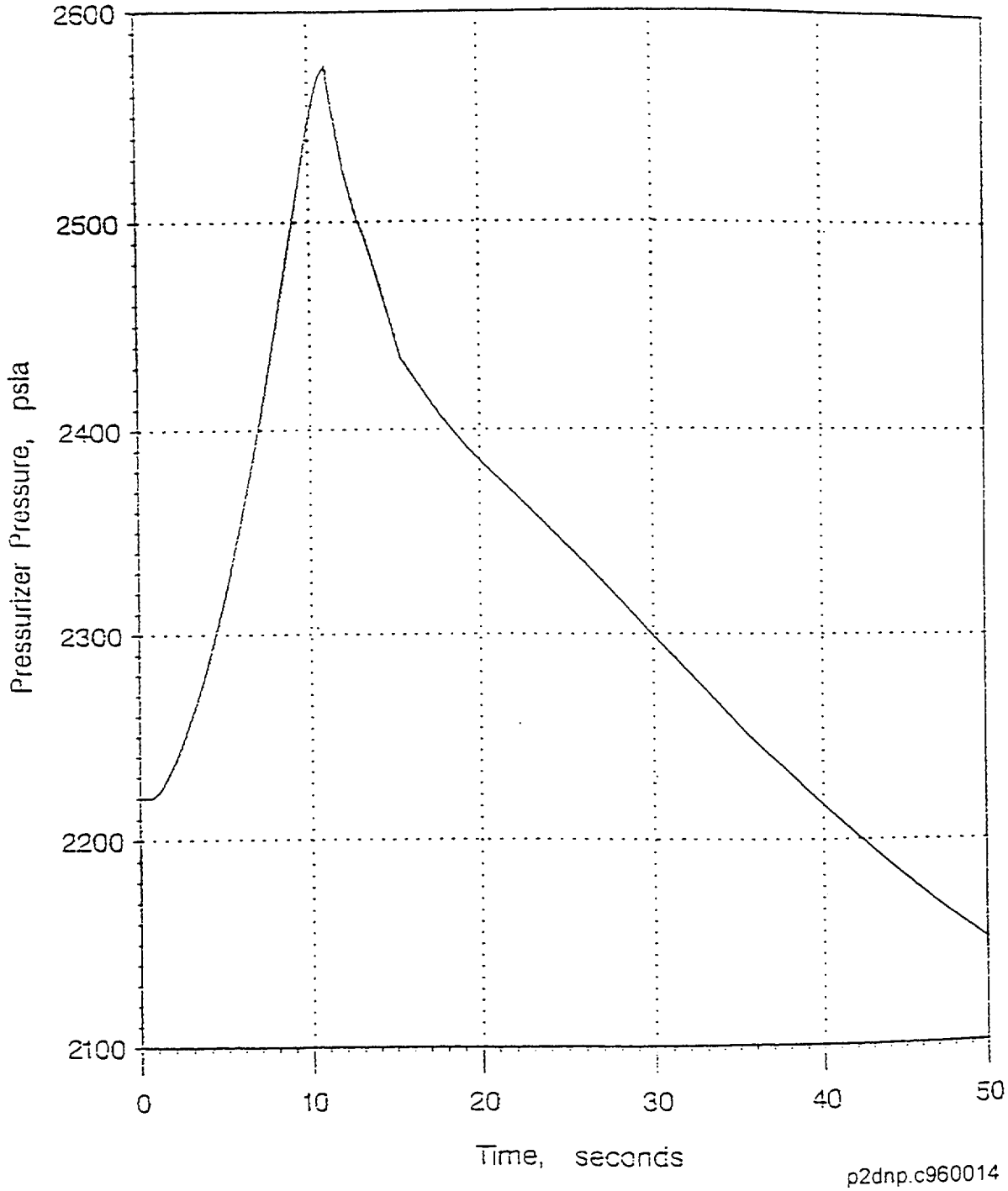

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Figure 6.2.9-3

Prairie Island Safety Analyses

Loss of External Load/Turbine Trip

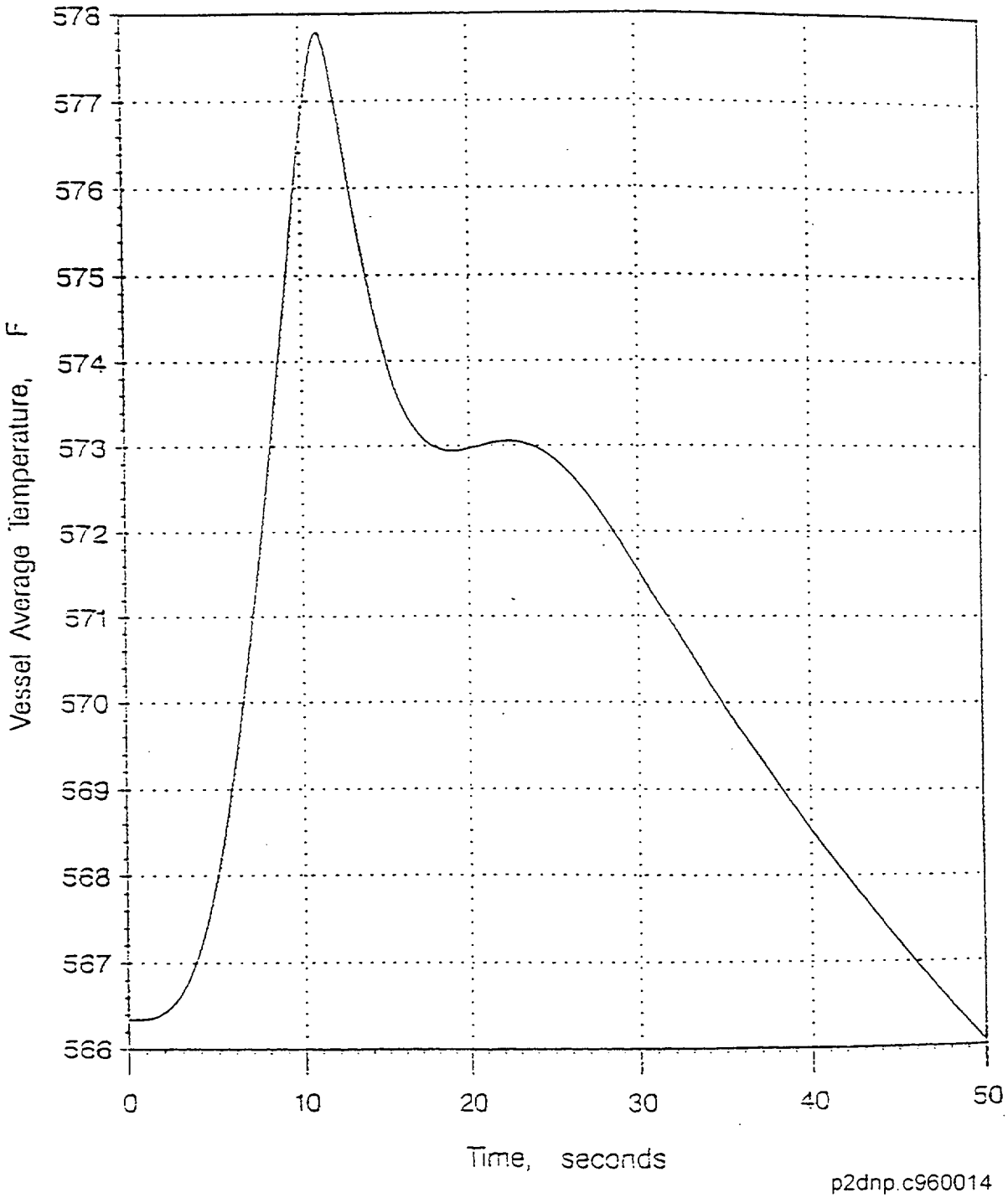

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Figure 6.2.9-4

Prairie Island Safety Analyses

Loss of External Load/Turbine Trip

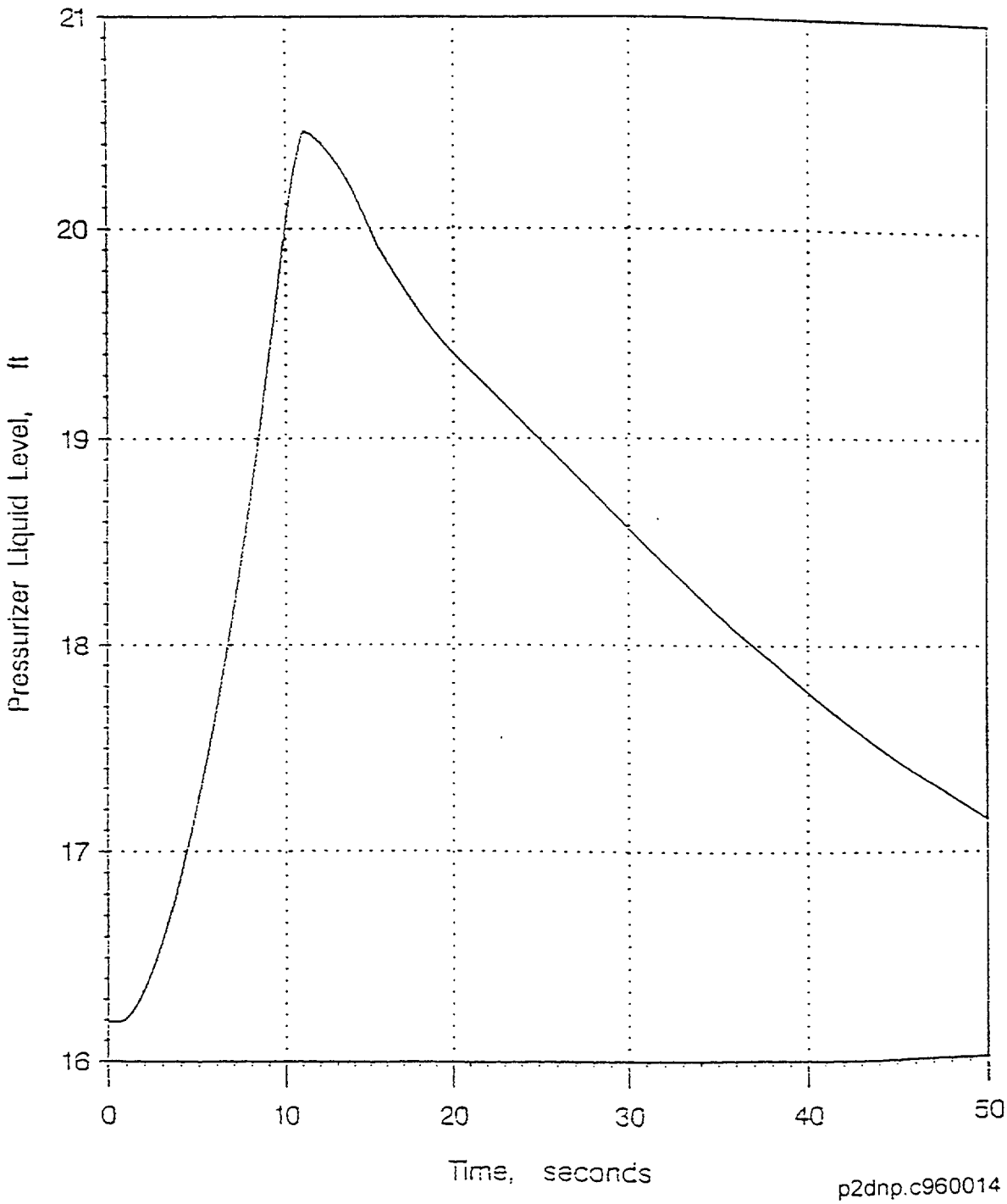

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Figure 6.2.9-5

Prairie Island Safety Analyses

Loss of External Load/Turbine Trip

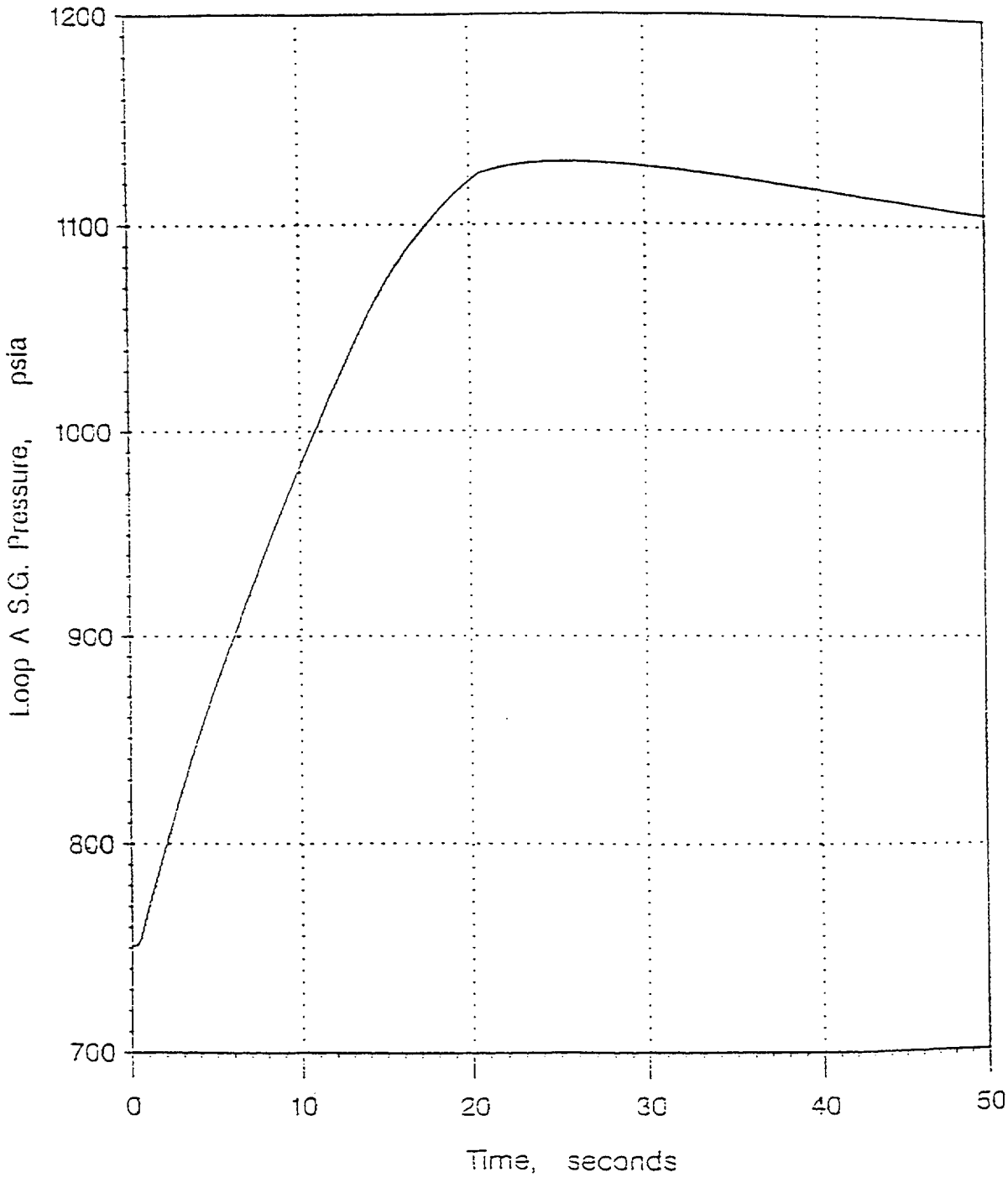

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Figure 6.2.10-1

Prairie Island Safety Analyses

Loss of Normal Feedwater

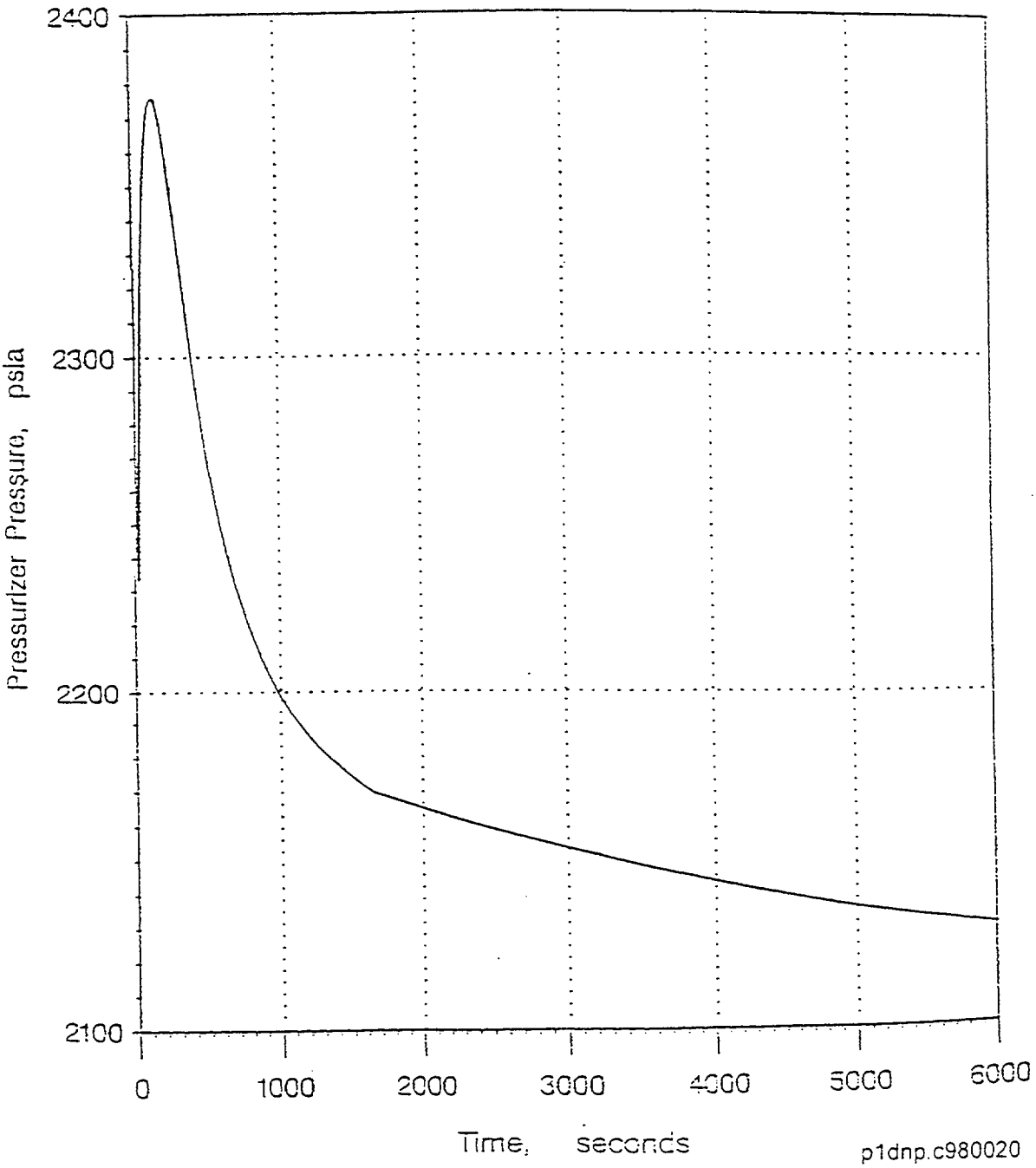

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Figure 6.2.10-2

Prairie Island Safety Analyses

Loss of Normal Feedwater

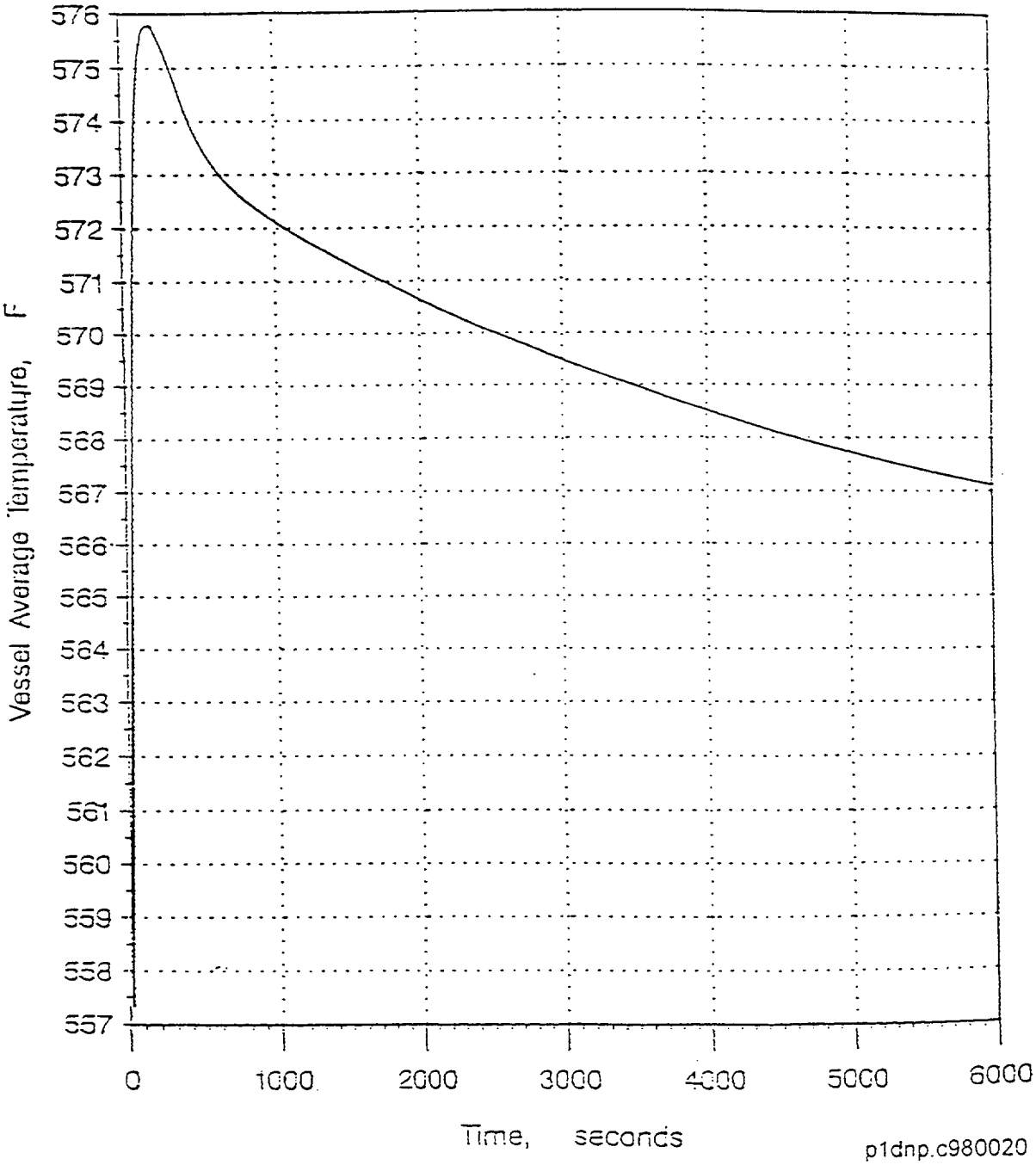

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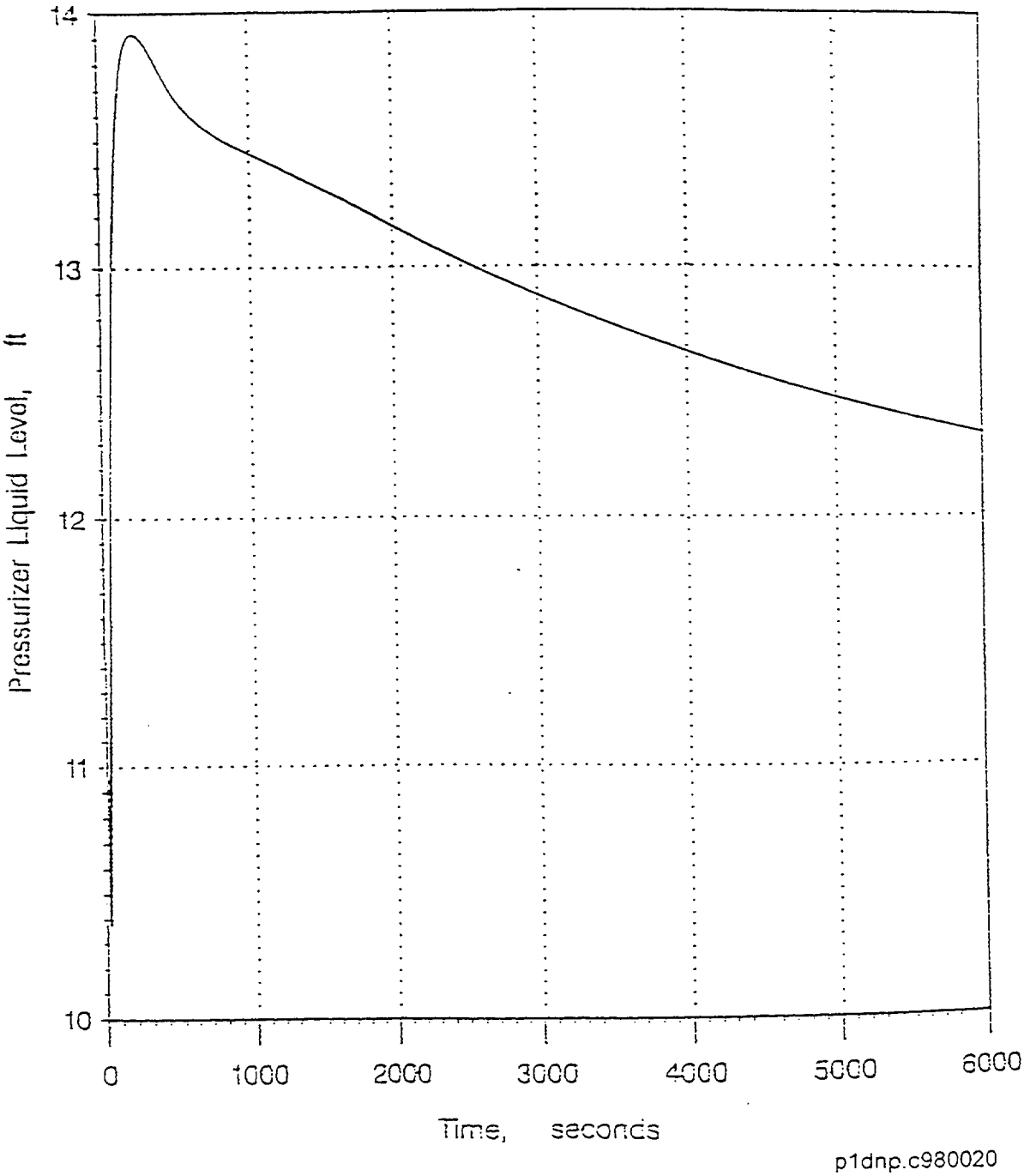
Figure 6.2.10-3

Prairie Island Safety Analyses

Loss of Normal Feedwater



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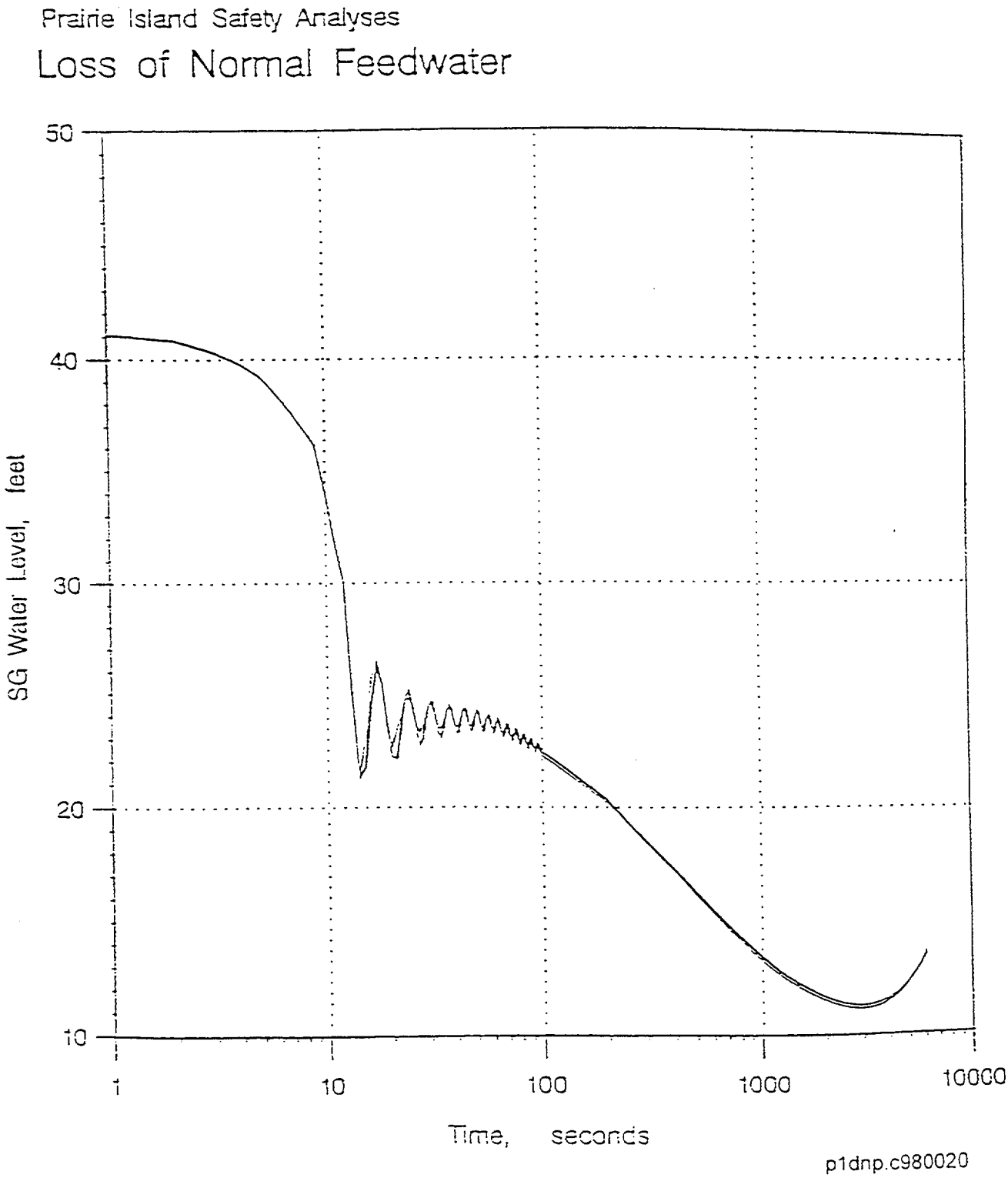

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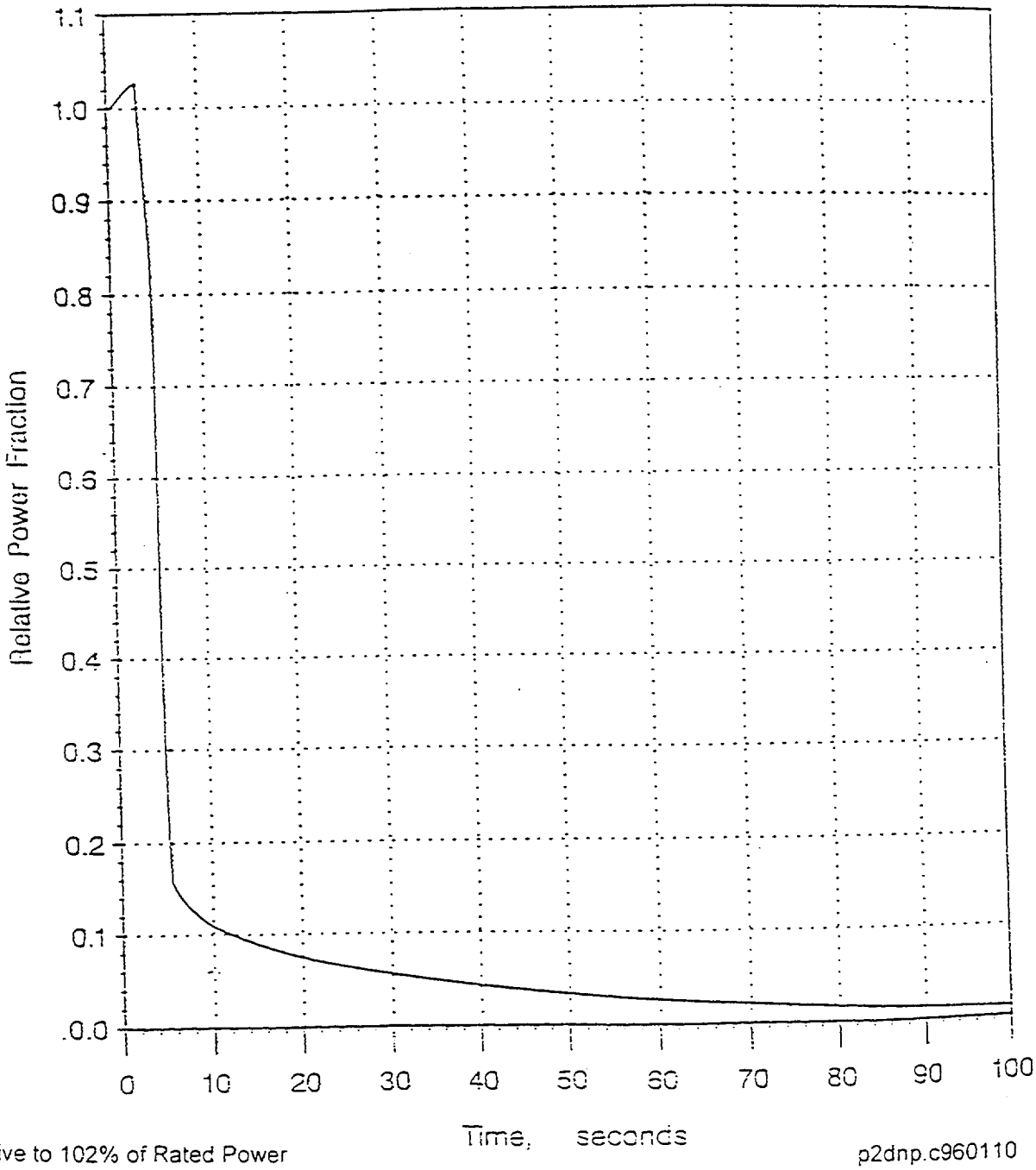
Figure 6.2.11-1

Prairie Island Safety Analyses

Loss of Reactor Coolant Flow/ 2/2 Pump Trip



Relative to 102% of Rated Power

p2dnp.c960110

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Figure 6.2.11-2

Prairie Island Safety Analyses

Loss of Reactor Coolant Flow/ 2/2 Pump Trip

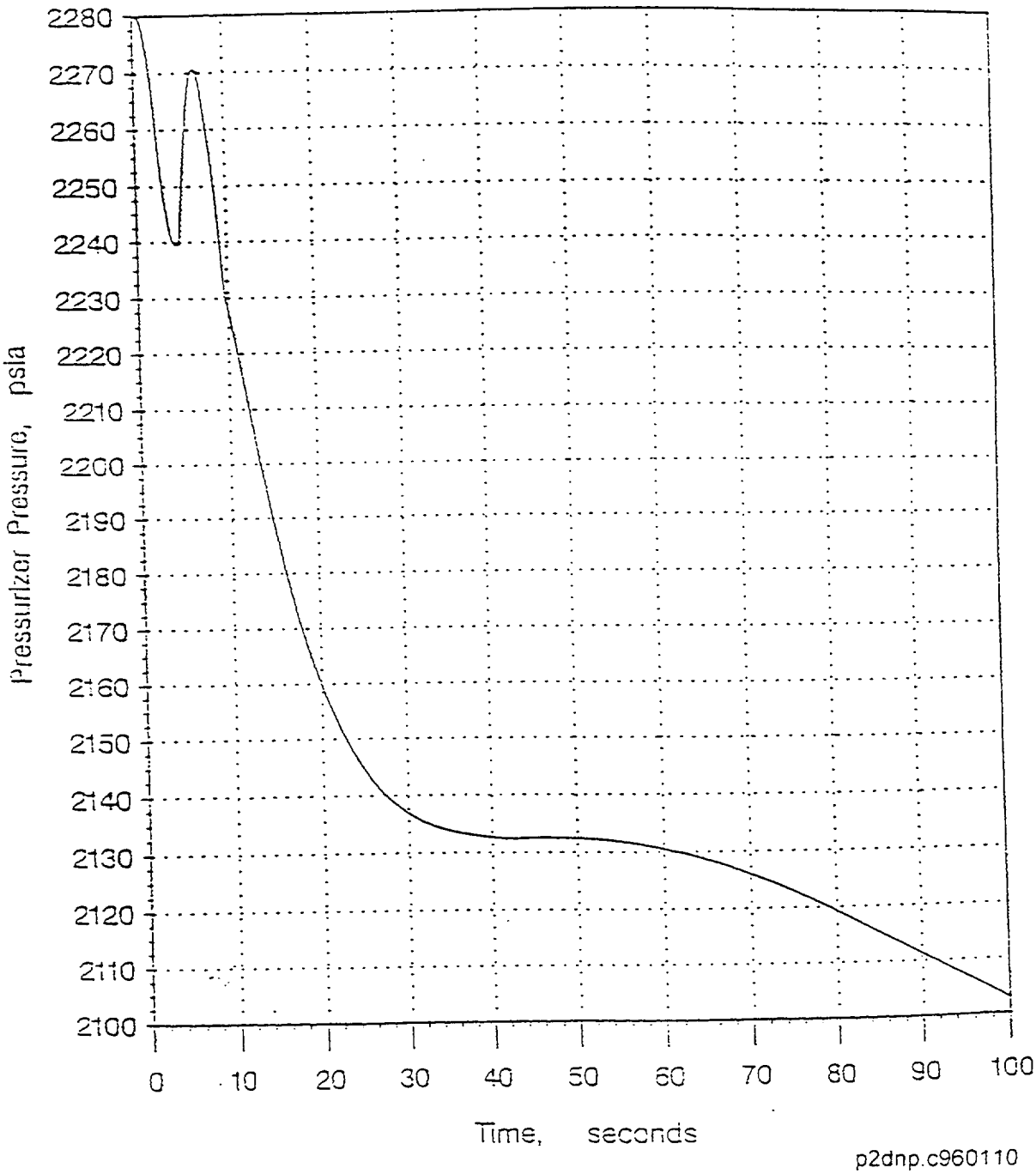

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Figure 6.2.11-3

Prairie Island Safety Analyses

Loss of Reactor Coolant Flow/ 2/2 Pump Trip

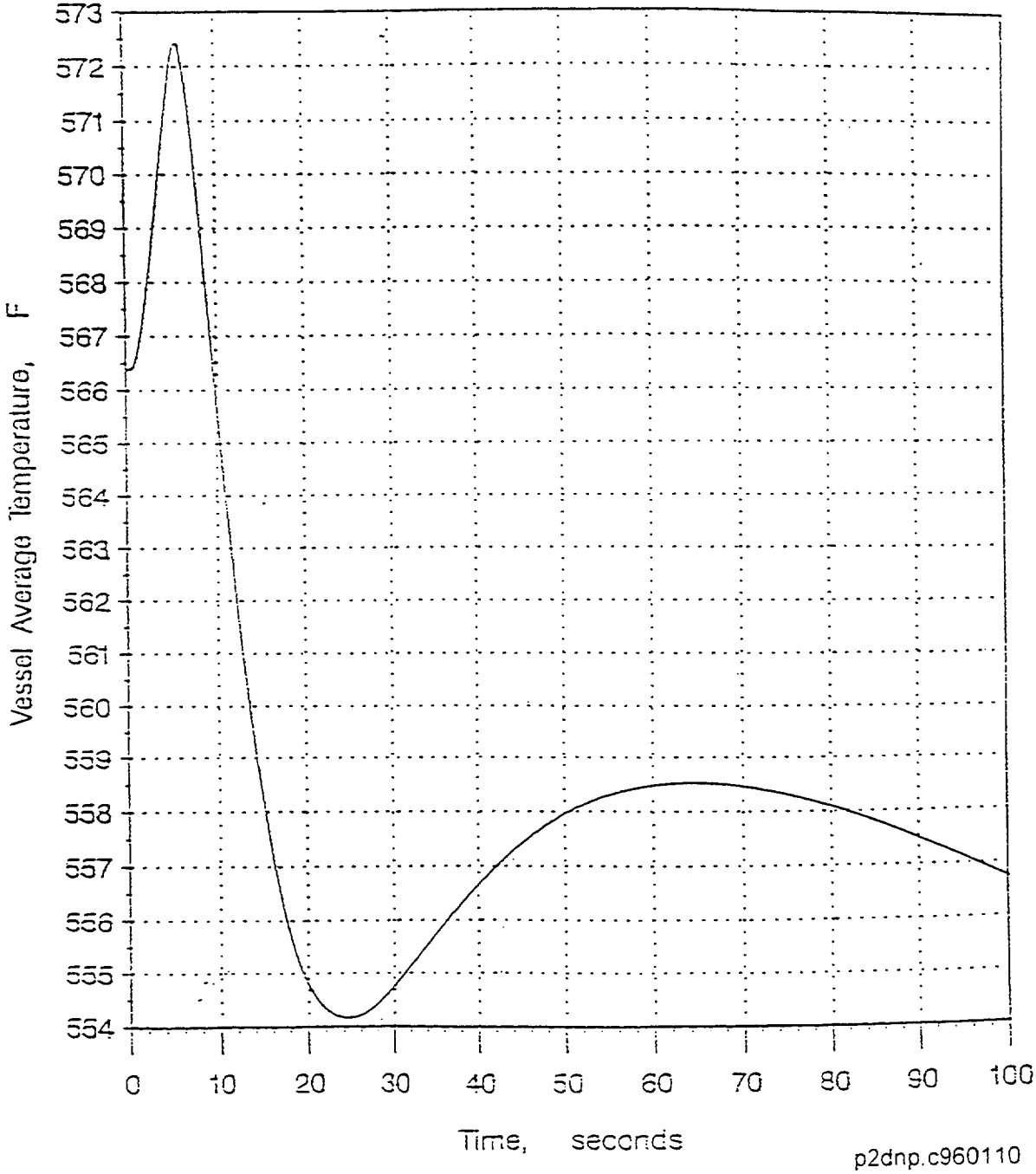

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Figure 6.2.11-4

Prairie Island Safety Analyses

Loss of Reactor Coolant Flow/ 2/2 Pump Trip

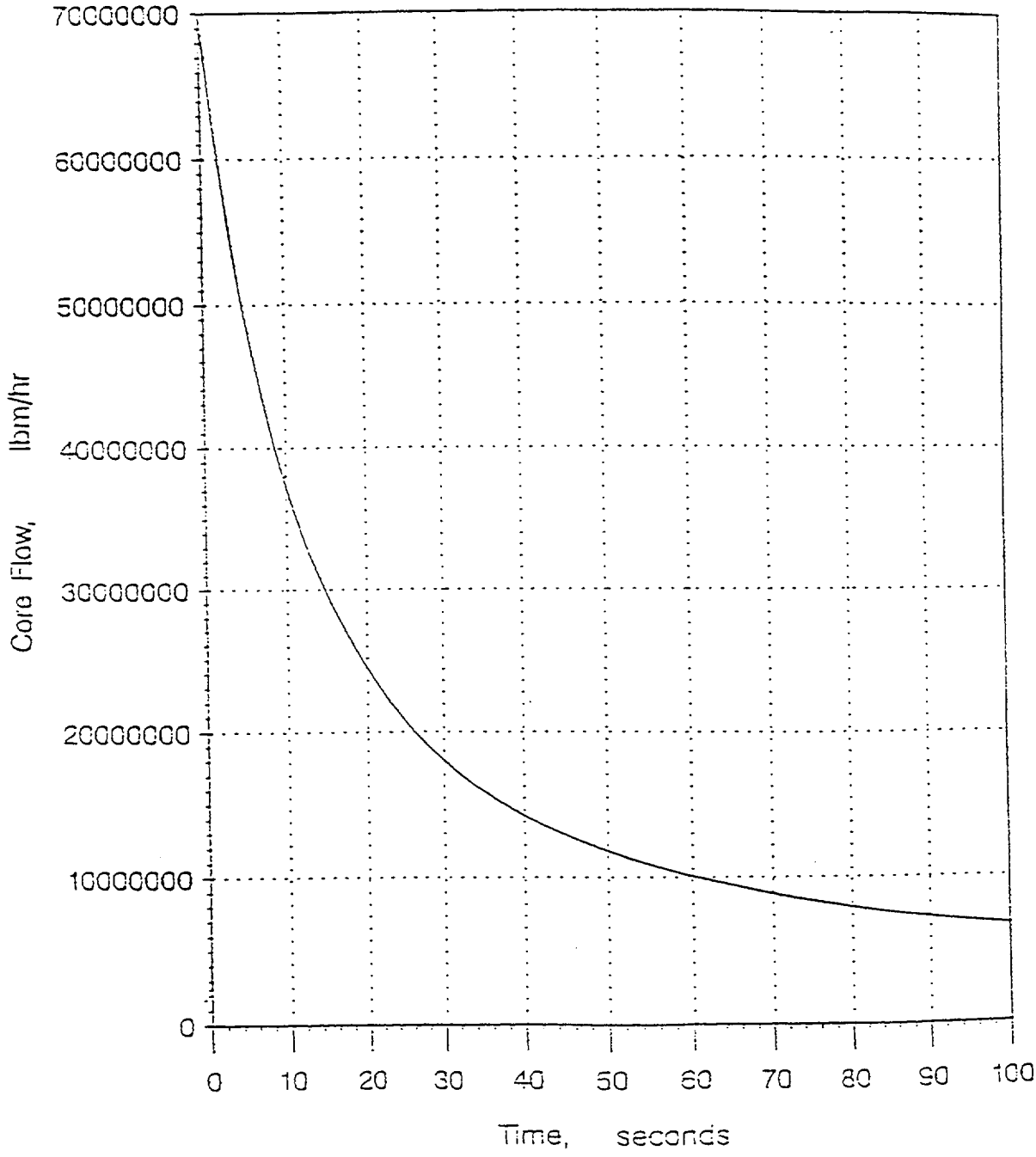

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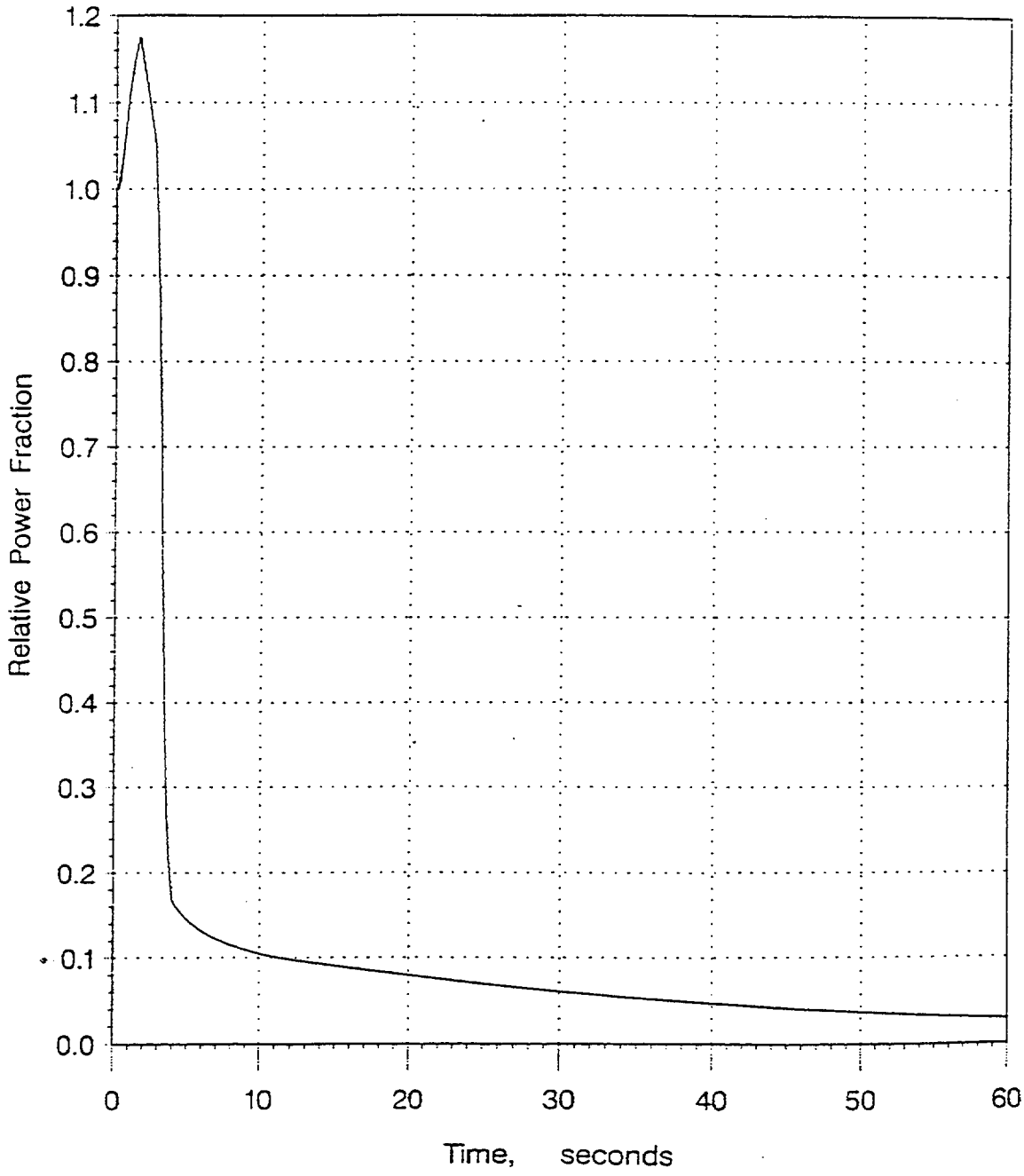
Figure 6.2.12-1

Prairie Island Safety Analyses

Locked Rotor/Maximum RCS Pressure



Relative to 102% of Rated Power

p2dnp.c000030

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Figure 6.2.12-2

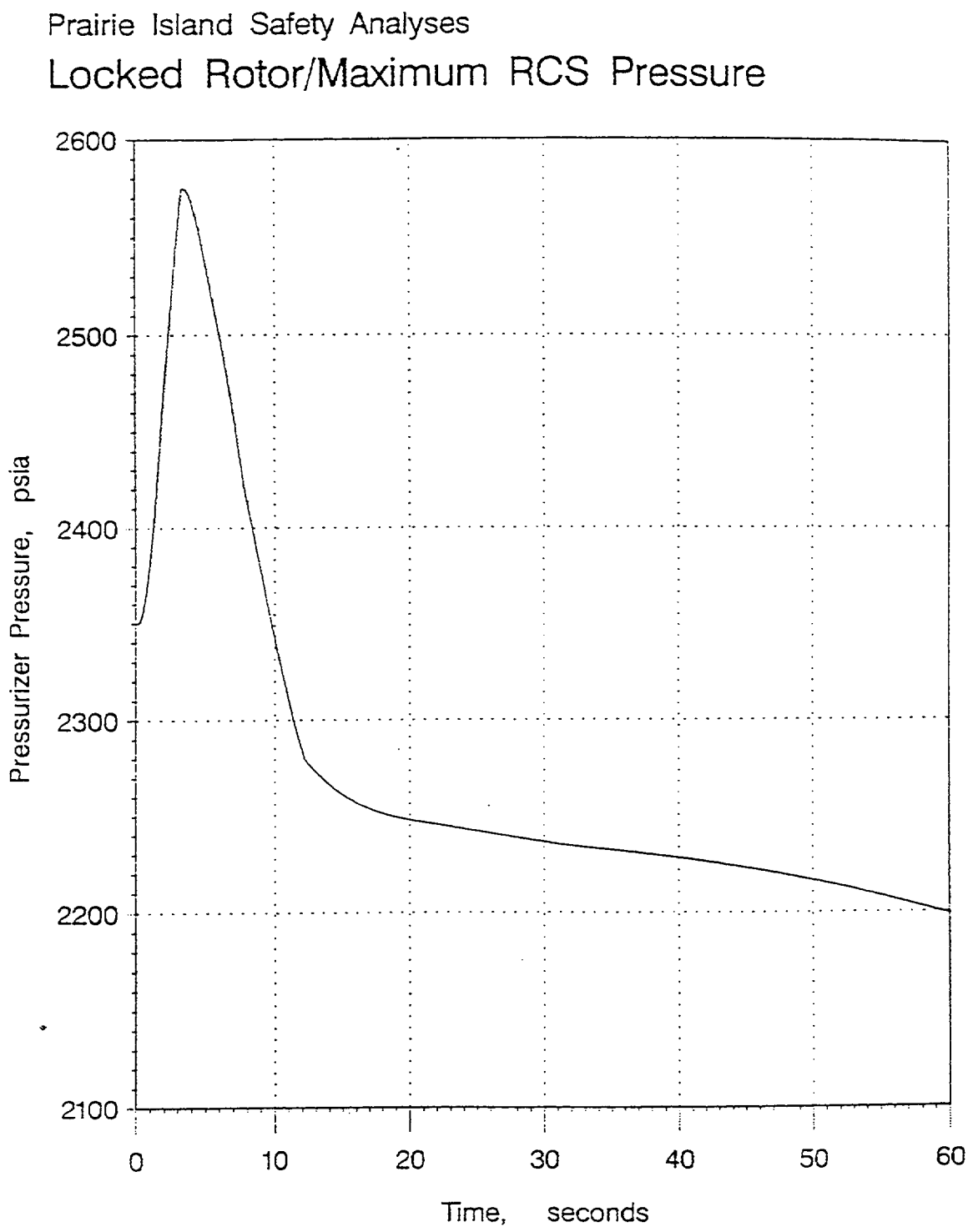

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Figure 6.2.12-3

Prairie Island Safety Analyses

Locked Rotor/Maximum RCS Pressure

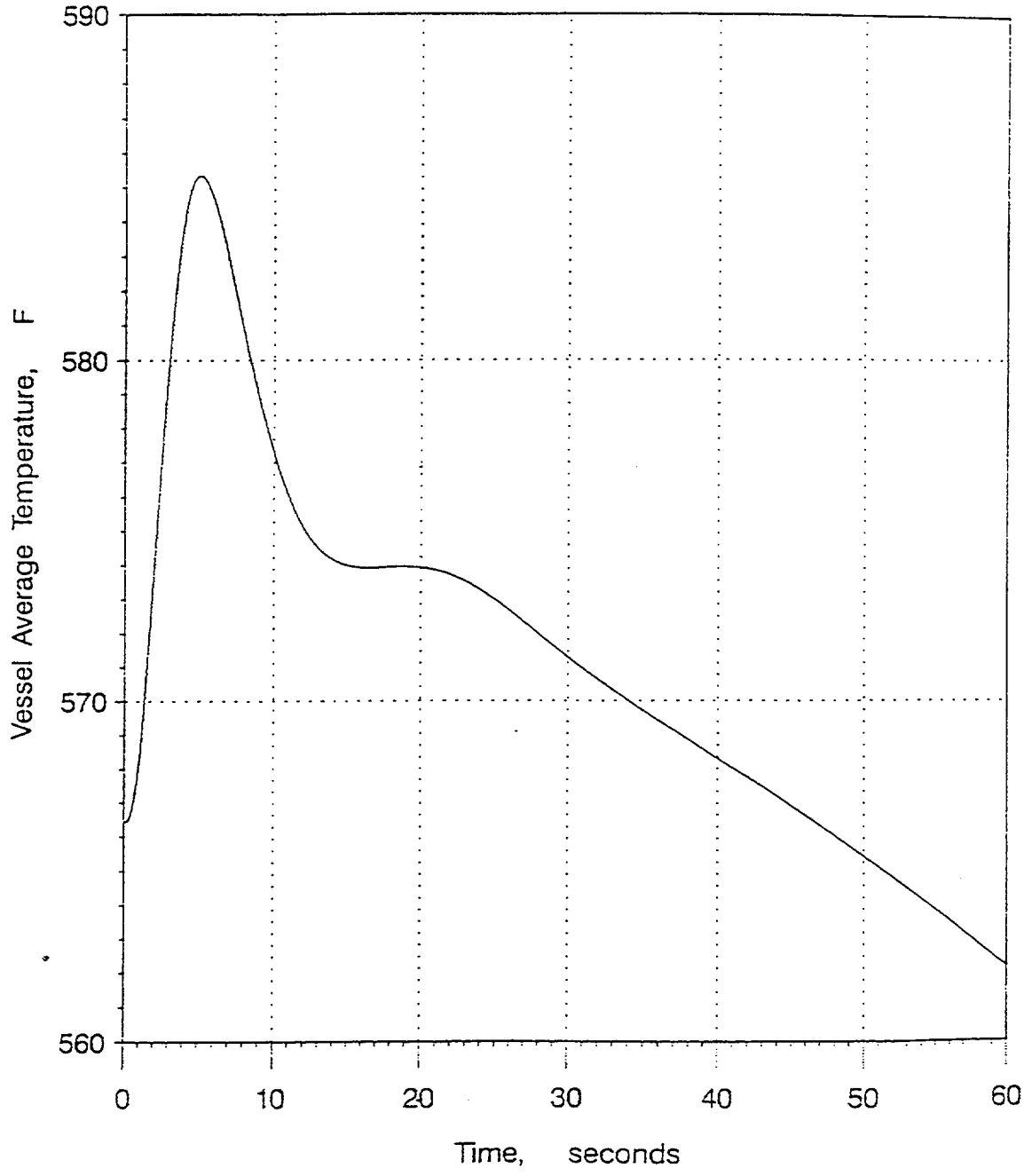

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Figure 6.2.12-4

Prairie Island Safety Analyses

Locked Rotor/Maximum RCS Pressure

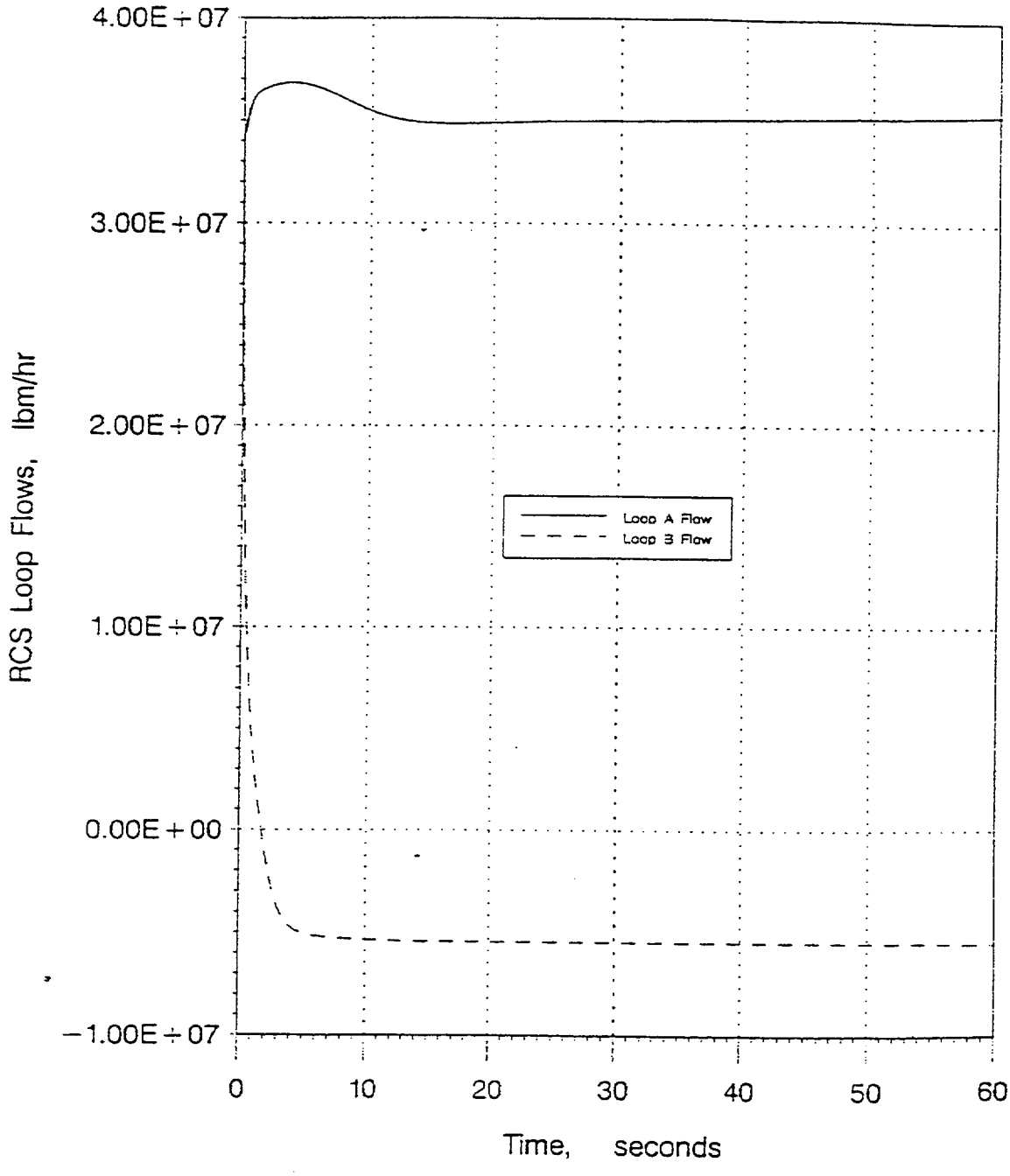

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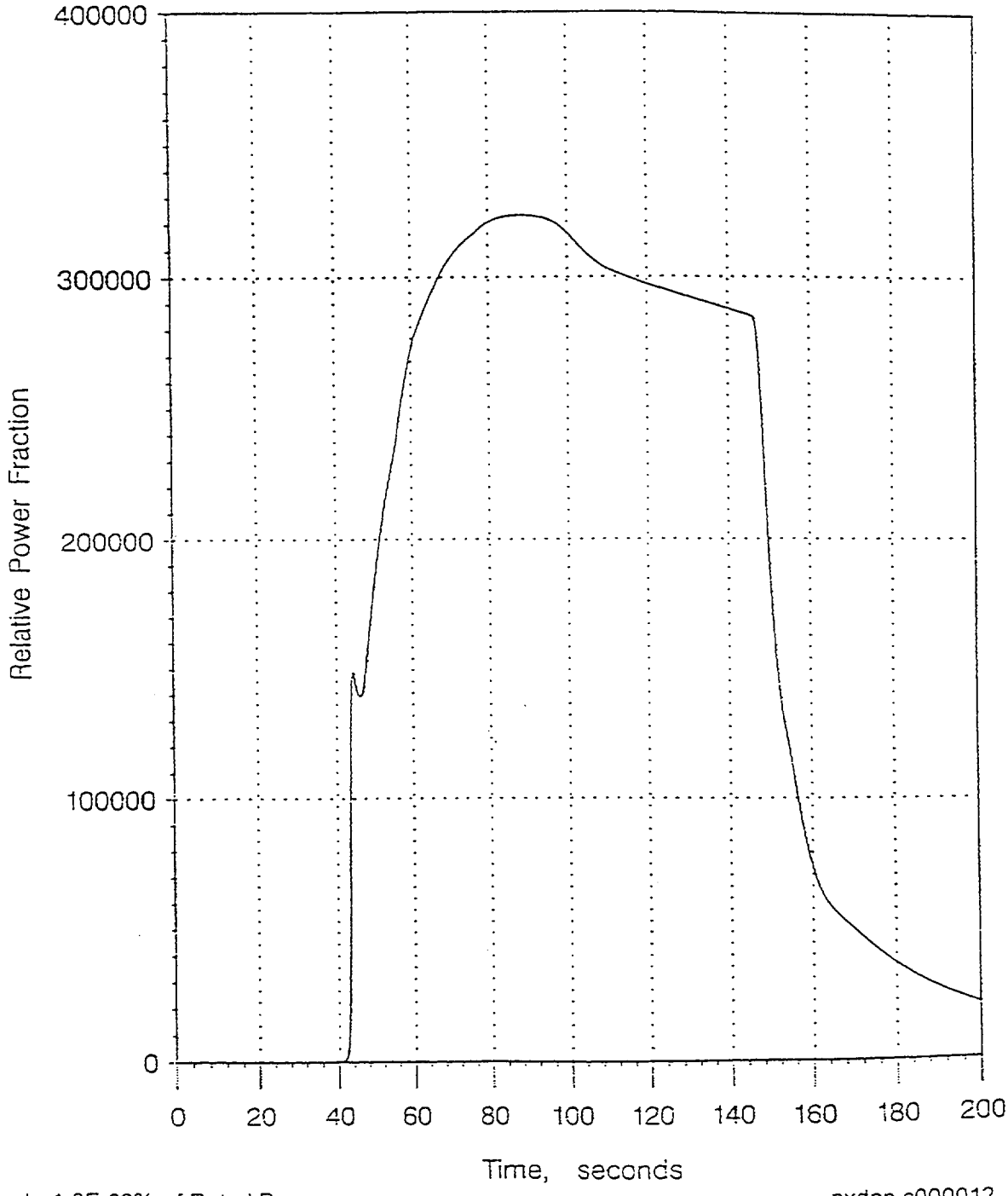
Figure 6.2.14-1

Prairie Island Safety Analyses

Large Steam Line Break



Relative to 1.0E-02% of Rated Power

pxdnp.c000012

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Figure 6.2.14-2

Prairie Island Safety Analyses

Large Steam Line Break

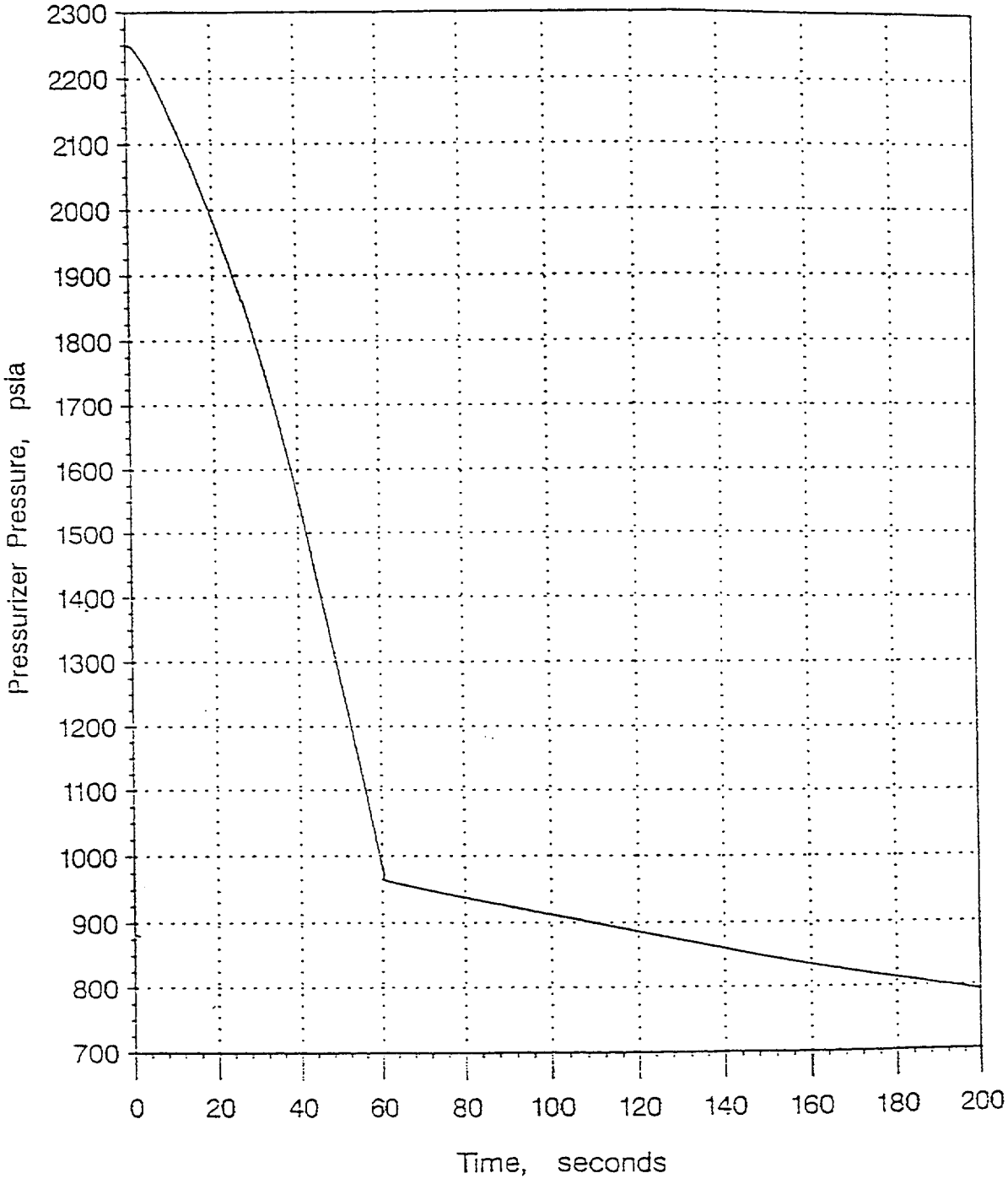

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Figure 6.2.14-3

Prairie Island Safety Analyses

Large Steam Line Break

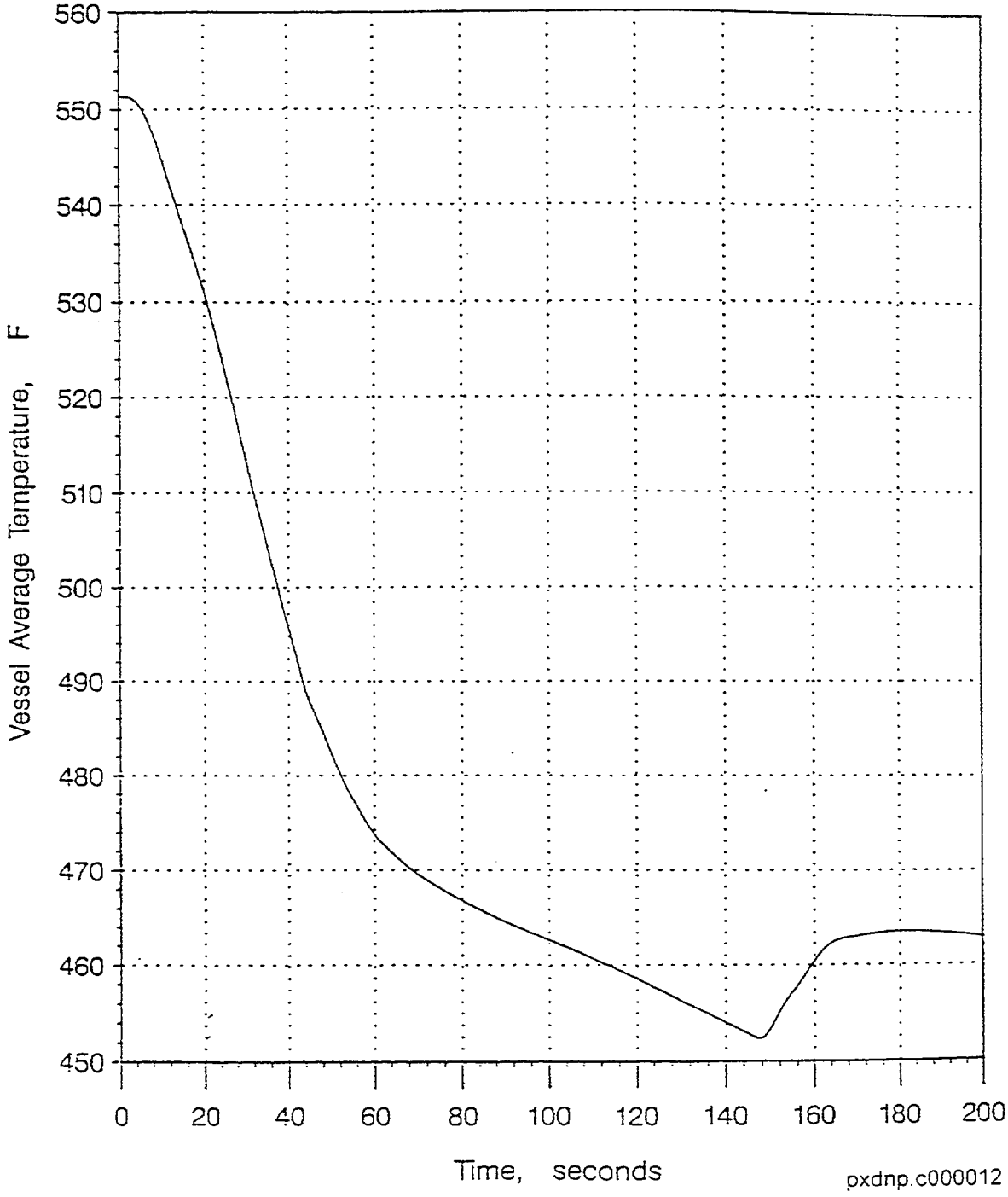

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Figure 6.2.14-4

Prairie Island Safety Analyses

Large Steam Line Break

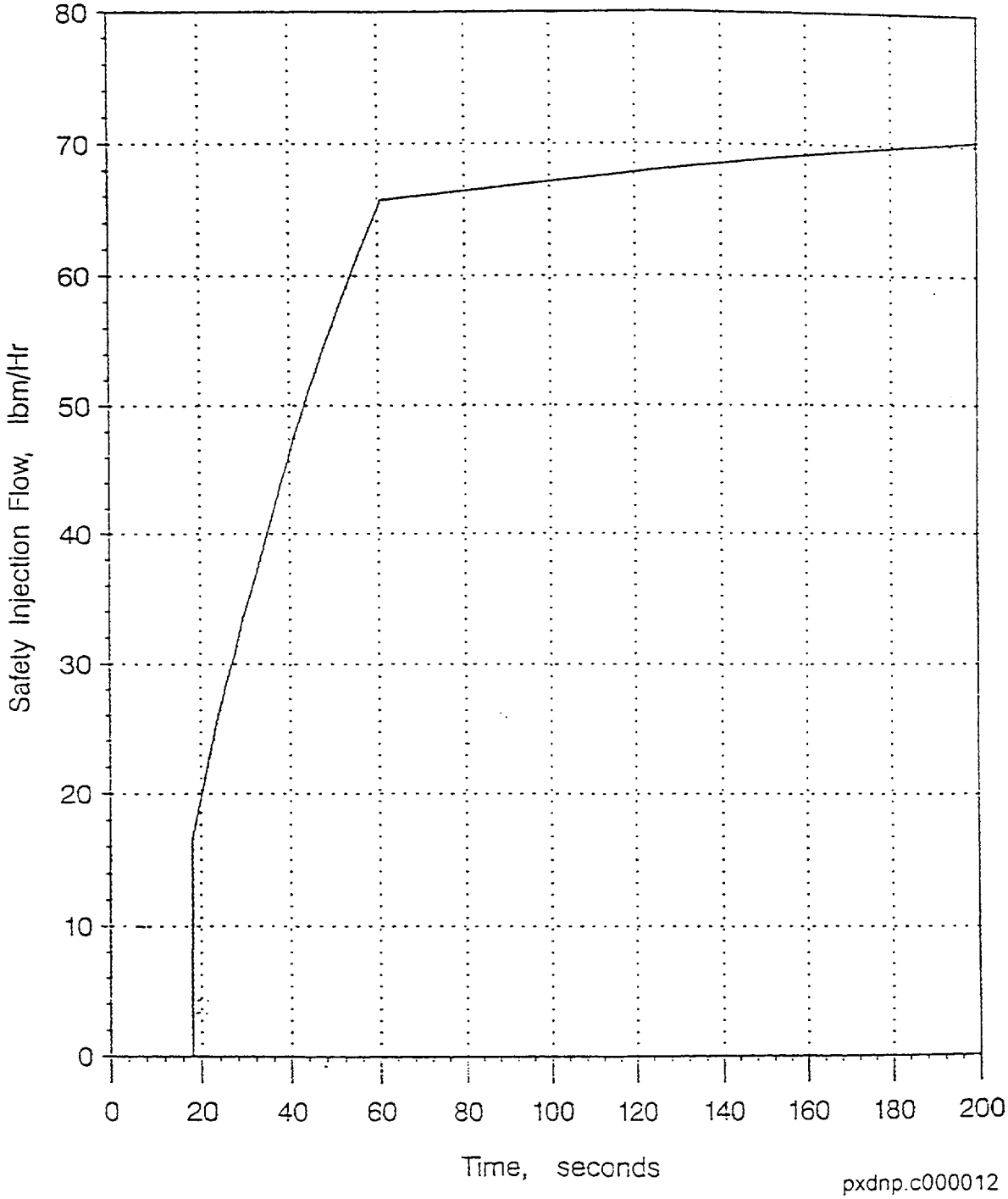

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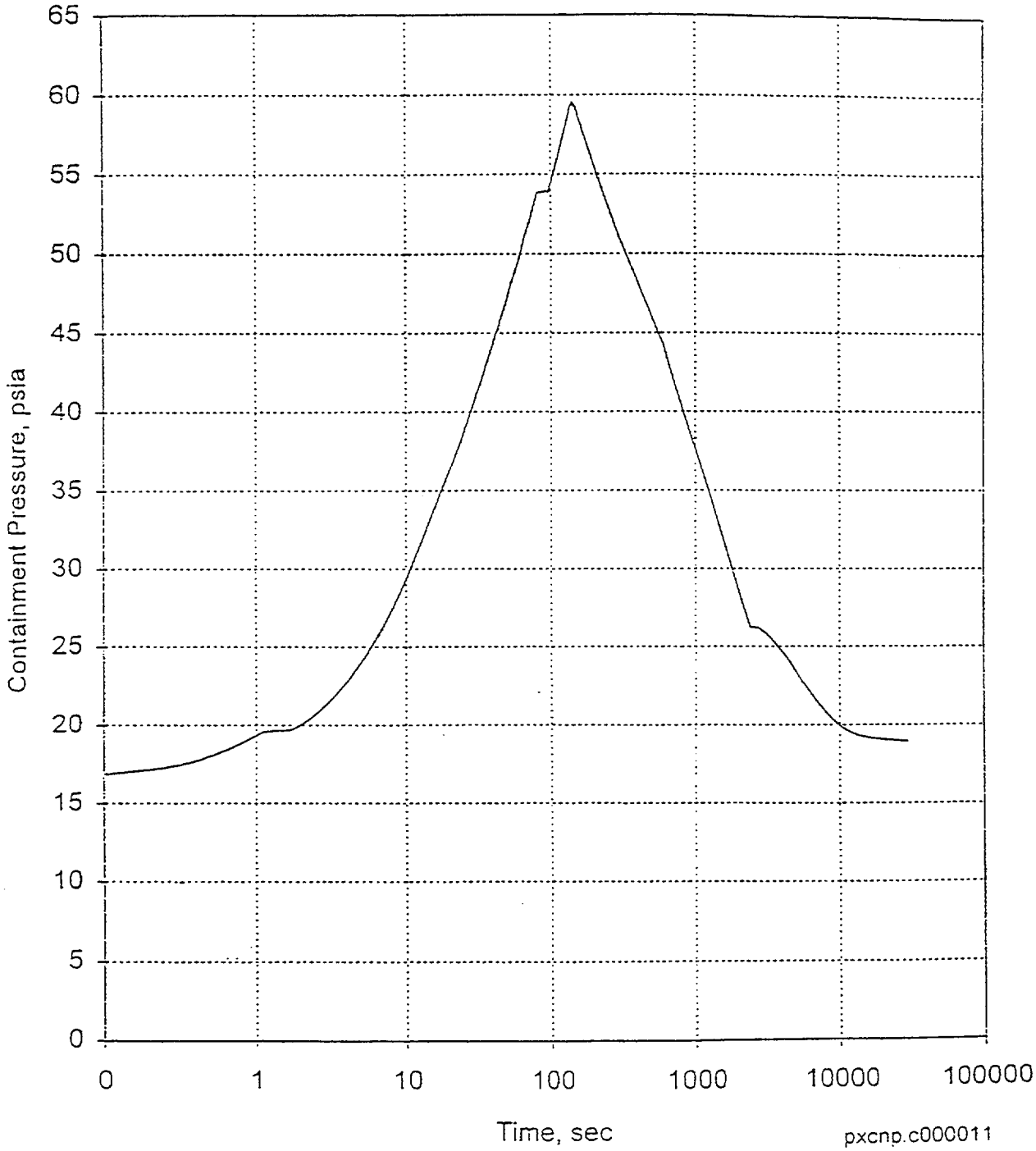
Figure 6.2.14-5

Prairie Island Safety Analysis

Large Steam Line Break



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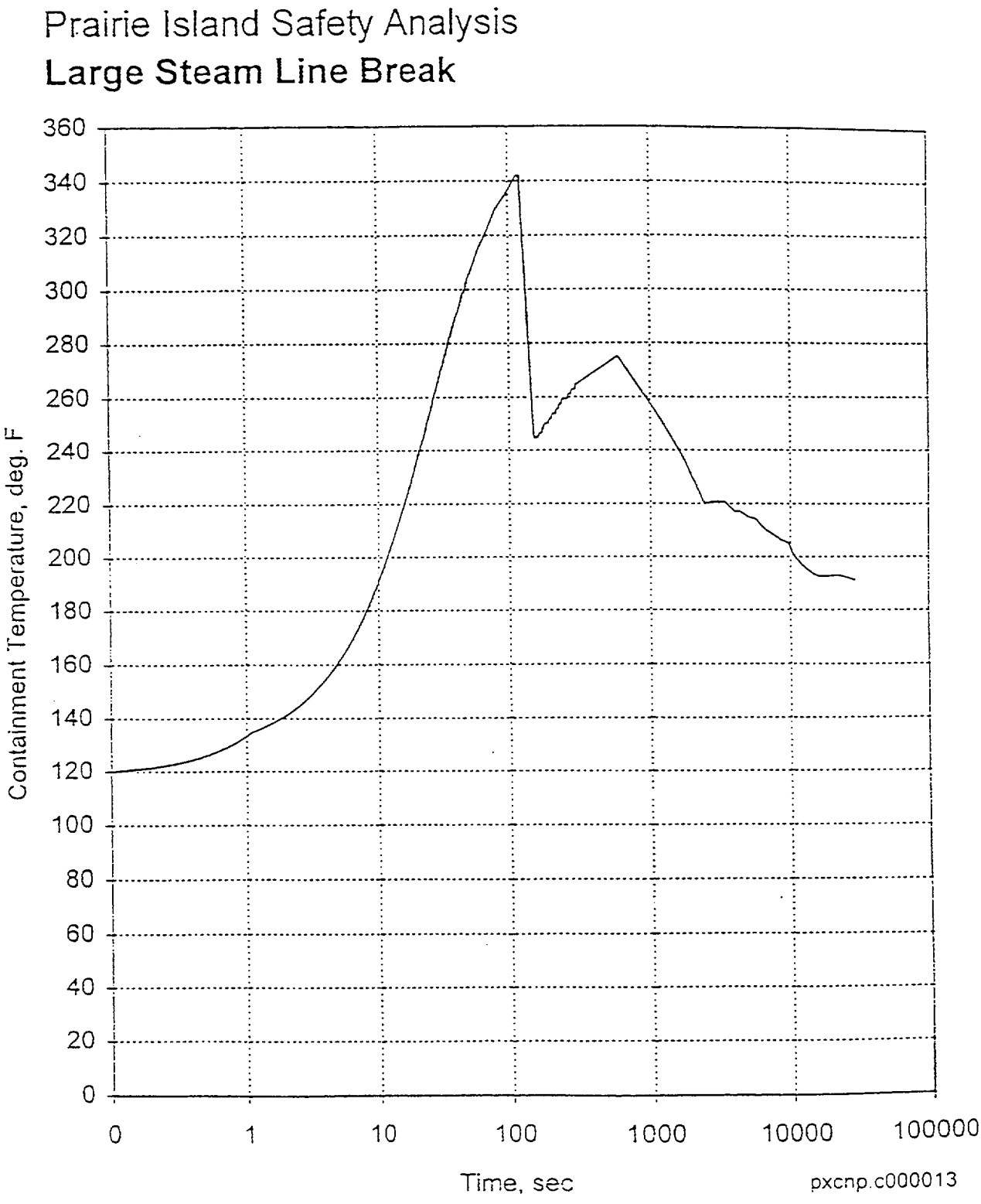

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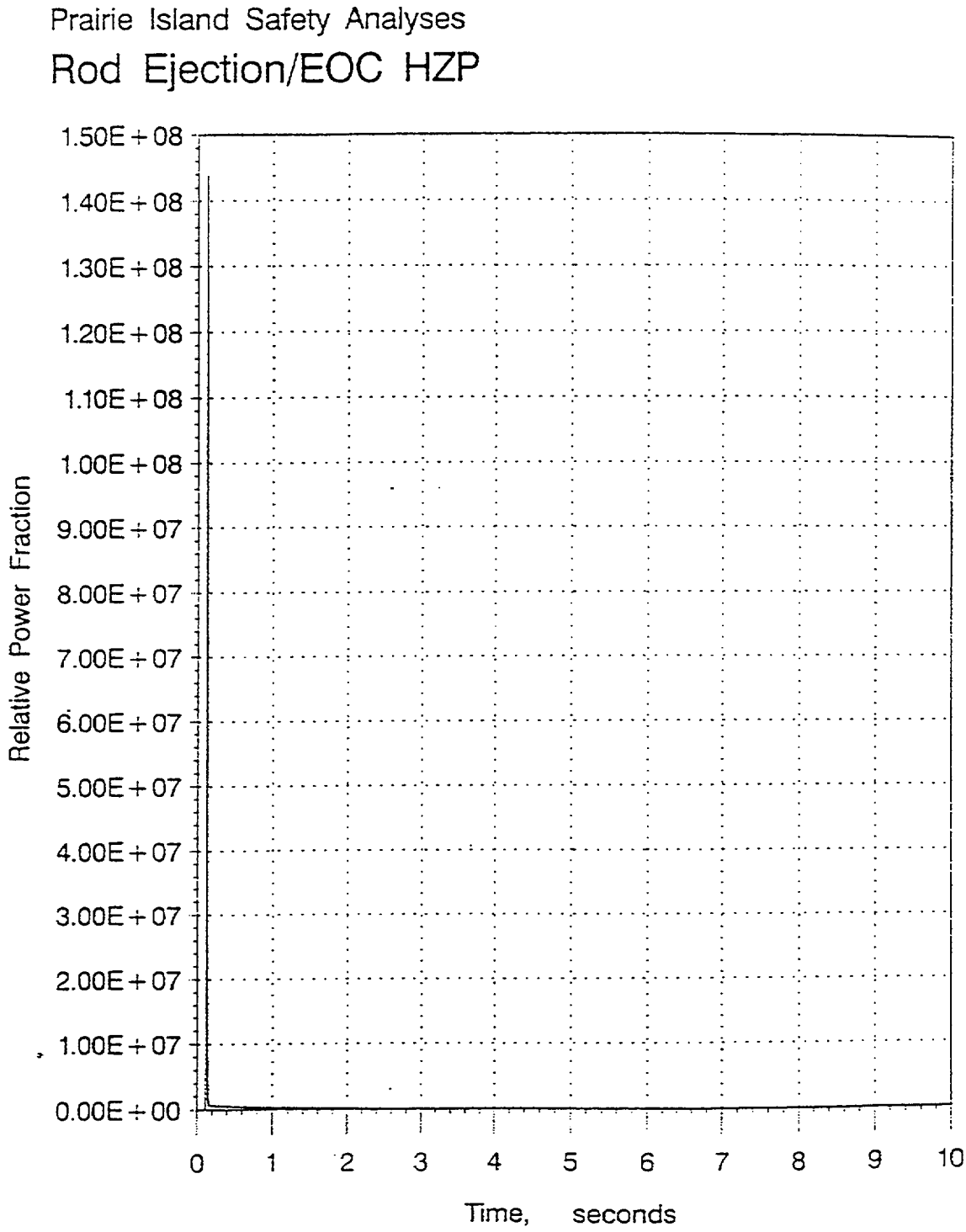

Relative to 1.02E-04% of Rated Power

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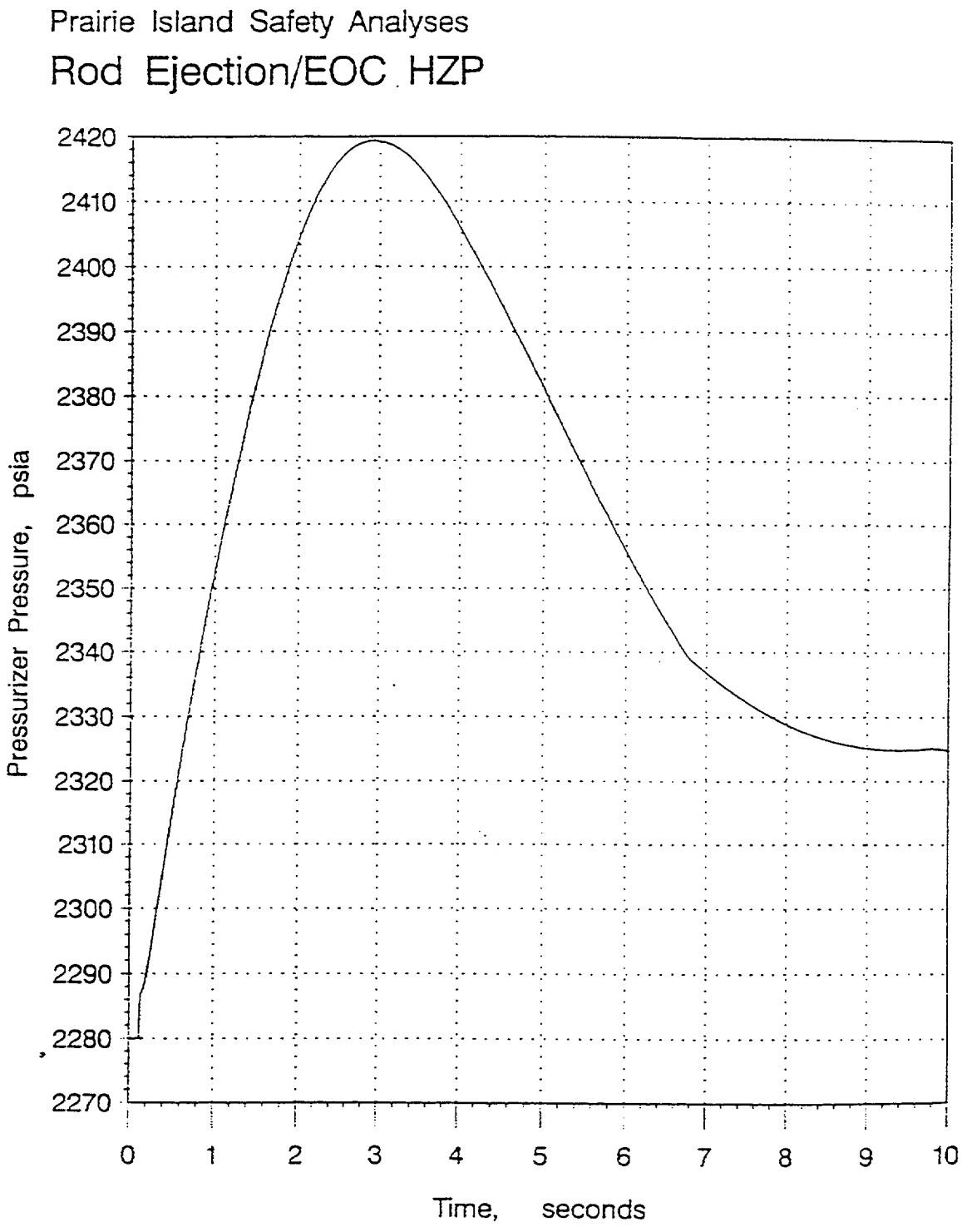

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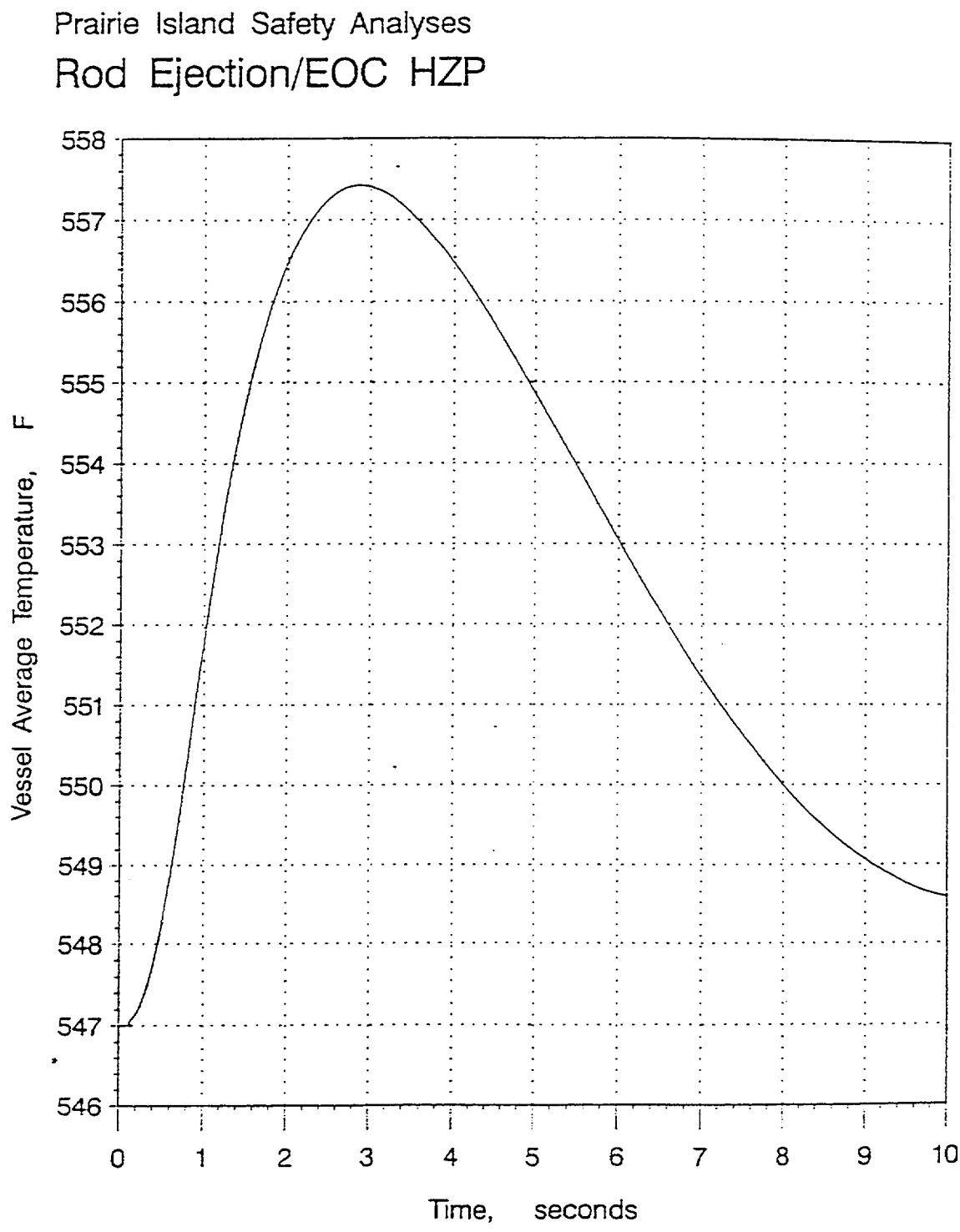

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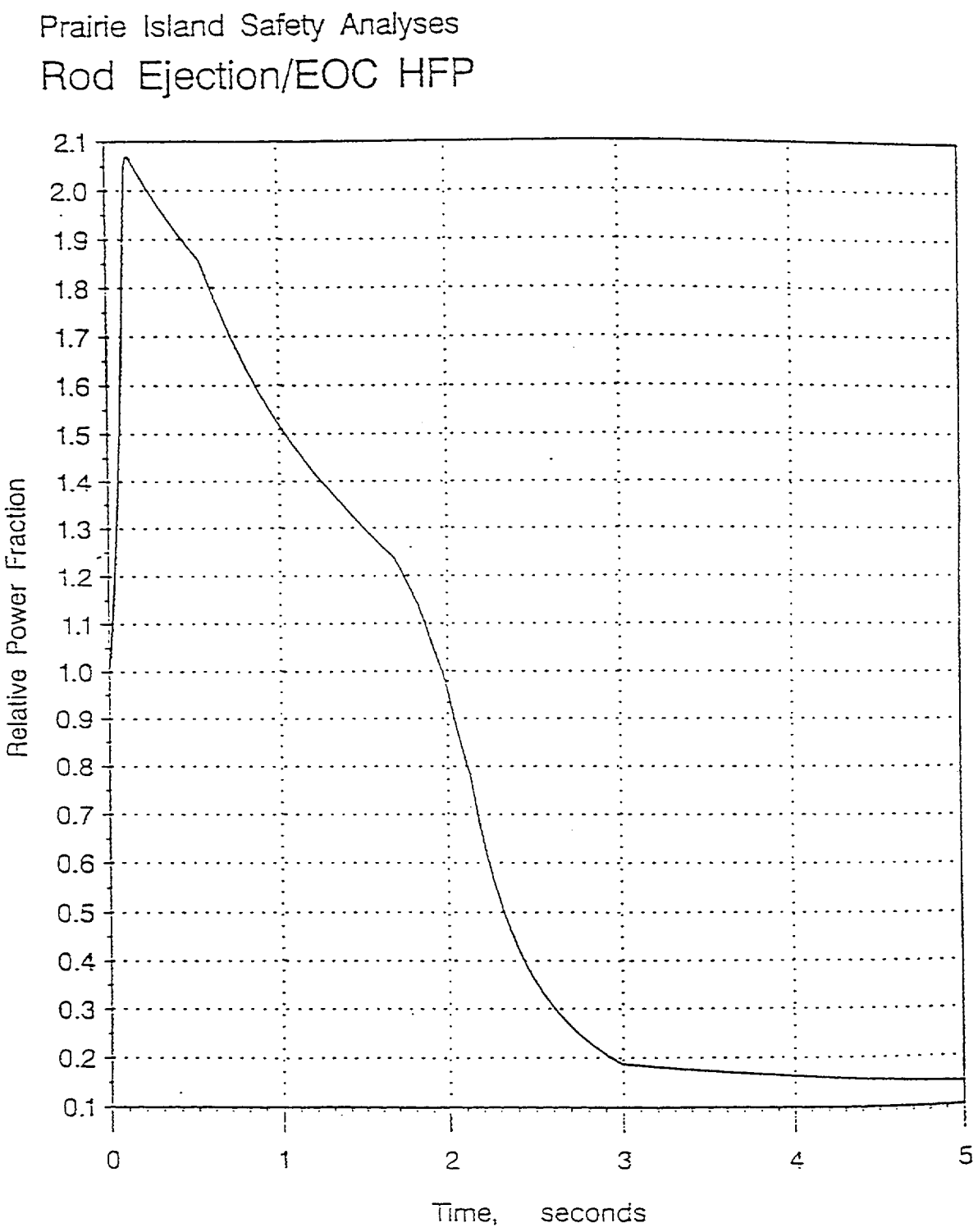

Relative to 102% of Rated Power

p1dnp003/89

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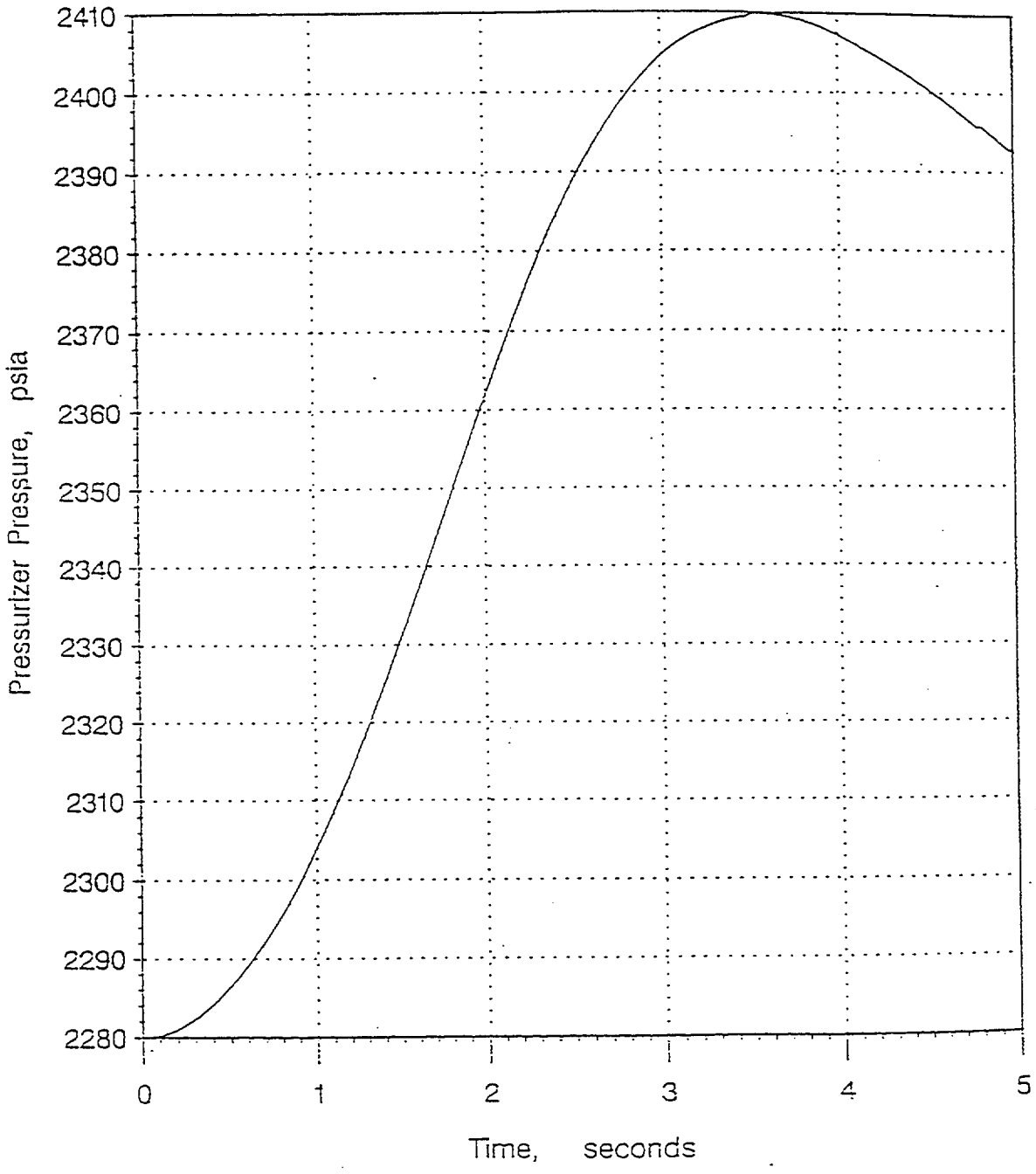
Figure 6.2.15-5

Prairie Island Safety Analyses

Rod Ejection/EOC HFP



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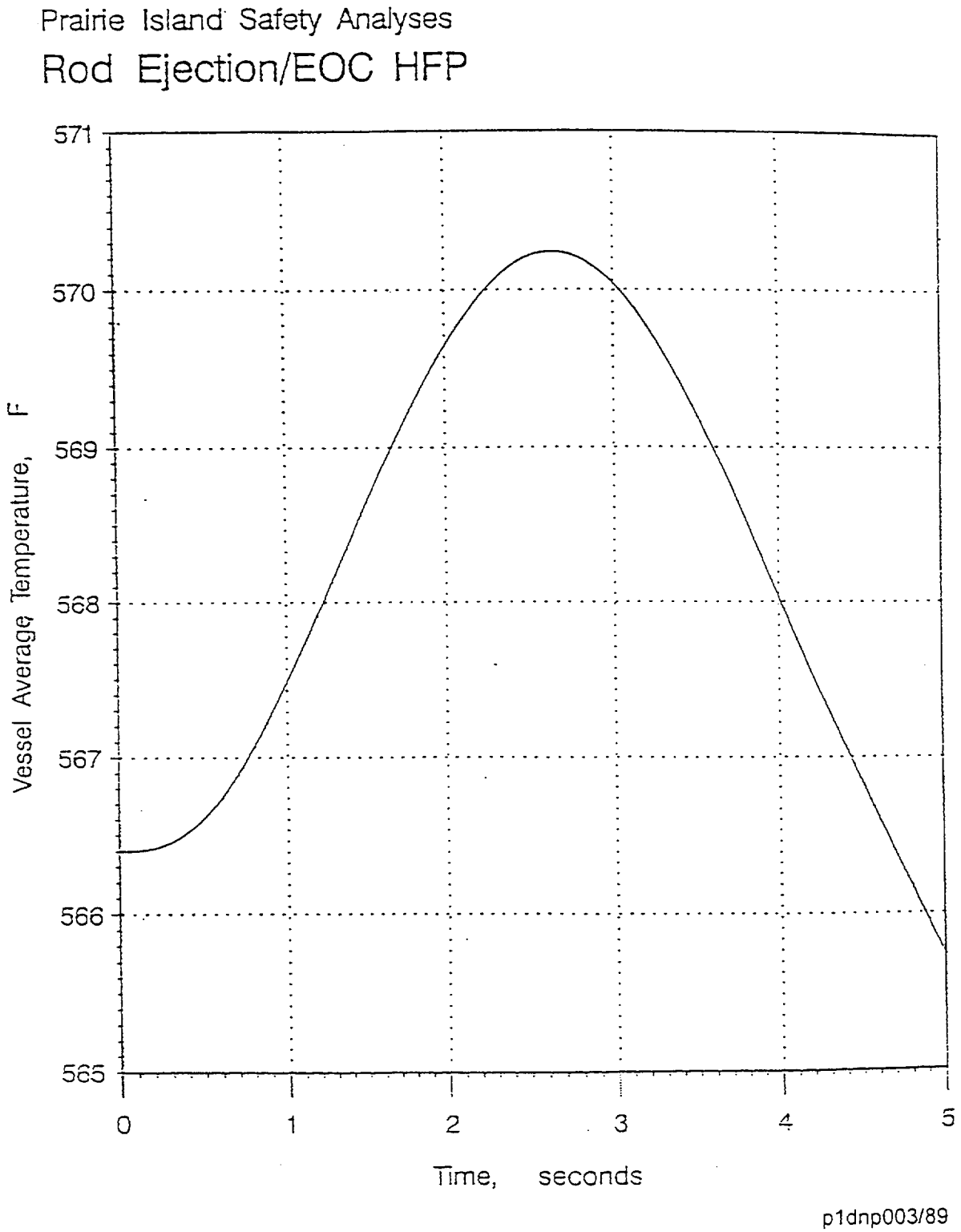

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Remove and replace all Appendix I Text and Tables

APPENDIX I

POSTULATED PIPE FAILURE ANALYSIS OUTSIDE OF CONTAINMENT

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APPENDIX I - POSTULATED PIPE FAILURE ANALYSIS OUTSIDE OF CONTAINMENT

INTRODUCTION

In an Atomic Energy Commission (A Giambusso) letter to Northern States Power (AV Dienhart) dated December 12, 1972 [Ref. 1], the AEC stated that Prairie Island "...should be designed so that the reactor can be shutdown and maintained in a safe shutdown condition in the event of a postulated rupture, outside of containment, of a pipe carrying high energy fluid, including the rupture of the largest pipe in the main steam and feedwater systems". This letter requested information on how the plant design would be revised to accommodate the postulated pipe ruptures and how any proposed modifications would address the guidelines and criteria contained in the attachment to the letter. Additional requests for information and clarification of AEC criteria are contained in AEC (A Giambusso) letters to NSP (AV Dienhart) dated January 11, 1973 [Ref. 2] and February 9, 1973 [Ref. 3].

Although the Giambusso letters were only applicable to high energy line breaks outside containment, a conservative engineering judgement was made to perform a similar review of the main steam and feedwater lines inside containment utilizing the criteria from the Giambusso letters. This review resulted in installation of impingement barriers on portions of these lines. This information was not included in the FSAR, but was added to this Appendix for completeness.

Nuclear Regulatory Commission (NRC) Generic Letter 87-11 (GL 87-11) [Ref. 4] relaxed the requirements for postulating arbitrary intermediate breaks and leakage cracks in high energy piping systems. This Appendix includes information on NSP's response to the Giambusso letters and NSP's subsequent application of GL 87-11 criteria.

I.1 HIGH ENERGY PIPING SYSTEMS AND REQUIRED EQUIPMENT

I.1.1 Definition of High Energy Piping Systems

A piping system is defined as having pressure retaining components consisting of straight or curved pipe and pipe fittings such as elbows, tees and reducers. The boundaries of a system are defined in terms of a piping run. A piping run interconnects components such as pressure vessels, pumps and rigidly fixed valves or structural anchors that may act to restrain pipe movement beyond that required for design thermal displacement. A branch run differs from a main piping run only in that it originates at a piping intersection as a branch of the main pipe run.

High energy piping systems are defined as those having a service temperature of 200°F and above and a design pressure above 275 psig. The plant operational conditions under which this definition applies, including normal reactor operation and upset conditions (e.g., anticipated operational occurrences). [Ref. 1, 2 & 3]

There is no ASME Section III, Code Class 1 piping outside containment for the Prairie Island Nuclear Generating Plant. Therefore, the criteria used for determining design basis break and leakage crack locations is ASME Section III, Code Class 2 and 3.

I.1.2 Identification of High Energy Piping Systems

The piping systems, or portions thereof, of the Prairie Island Nuclear Generating Plant which meet the definition of high energy are [Ref. 9.5]:

Main Steam

Feedwater

Chemical and Volume Control Letdown

Steam Generator Blowdown

Steam Supply to Auxiliary Feedwater Pump Turbine

I.1.3 Selection of Break and Crack Locations

The December 12, 1972 AEC letter [Ref 1] provided the criteria that was originally used at Prairie Island to select break and crack locations. The break location criteria required selecting the terminal ends of the piping run, any location along the pipe where the combined stress exceeded 0.8 ($S_h + S_A$) or expansion stress exceeded 0.8 S_A plus a minimum of two arbitrary intermediate locations based on high stress. The break size was defined to be twice the inside pipe diameter in length and a width that would yield a break area equal to the effective cross-sectional flow area upstream of the break location. The crack criteria required selecting any location along the length of the pipe. The crack was defined to be one-half the pipe diameter in length and one-half the pipe wall thickness in width.

Longitudinal breaks were to be postulated in piping runs of 4" nominal diameter and larger and would be parallel to the pipe axis oriented anywhere around the pipe circumference. Circumferential breaks were to be postulated in piping runs exceeding a nominal 1" diameter and oriented perpendicular to the pipe axis. Cracks could occur anywhere along the length of pipe. The most adverse locations and orientations were selected after considering potential jet impingement and environmental impact on nearby plant equipment.

GL 87-11 [Ref. 4] provided a relaxation in the criteria for selecting arbitrary intermediate pipe break and leakage crack locations as well as deleted the expansion stress criteria. This new criteria selected breaks at any location along the pipe where the combined stress exceeded 0.8 ($1.8 S_h + S_A$) and leakage cracks at any location where the combined stress exceeded 0.4 ($1.8 S_h + S_A$). GL 87-11 did not revise the break and crack criteria for type, size and orientation or the terminal ends.

I.1.4 Selection of Required Equipment

The equipment required to detect and mitigate the consequences of a high energy line design basis break or leakage crack is selected to accomplish the following functions:

- Reactor trip
- Reactivity control
- Reactor coolant system pressure control
- Reactor coolant system inventory control
- Event monitoring

Operability of this equipment provides the capability to achieve hot shutdown either by operator actions or by automatic reactor protection functions. This equipment also provides the capability for ultimately achieving cold shutdown.

The rupture of high energy piping systems is discussed in various sections of the USAR and identifies the assumptions made for those postulated events. Main steam is discussed in Section 14.5, feedwater in Section 14.4, CVCS letdown in Section 10.2, steam generator blowdown in Section 9.2 and steam supply to the auxiliary feedwater pump turbine is considered a small main steam line break.

For the purposes of this Appendix, these assumptions can be summarized as follows:

The pipe rupture occurs simultaneously with a loss of off-site power; an accident in one unit and hot shutdown in the other unit; a single active failure in the short term; any rupture in the secondary side steam system is not isolatable (i.e., the break is upstream of an MSIV or the assumed single failure is one MSIV does not close) and the entire inventory of one steam generator blows down; all required equipment is operable from the Control Room or accessible for manual operation.

The pipe rupture occurs at the following plant operating conditions:

Main steam - hot shutdown for peak compartment pressure calculation and full power for peak compartment temperature calculation

Feedwater - full power for break compartment pressure calculation and 25% power for flooding evaluation

CVCS letdown - hot shutdown

Steam generator blowdown - hot shutdown

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I.2 FEATURES FOR PROTECTION AGAINST THE EFFECTS OF HELB EVENTS

I.2.1 Pipe Rupture Induced Loads

Pipe Whip

The analysis of reaction loads resulting from pipe ruptures took into consideration the duration, initial conditions, jet stream dynamics and system pressure characteristics.

The location of breaks for pipe whip considerations was originally defined by the criteria in the Giambusso letter [Ref. 1]. Application of the GL 87-11 criteria [Ref. 4] eliminated all of the arbitrary intermediate break locations to be considered for pipe whip analysis.

The loads induced from the pipe rupture include the effects of any line restrictions, such as flow limiters, between the pressure source and the break location. The effect of break opening geometry on the magnitude of reaction load is incorporated in the analysis by the application of an appropriate, but conservative, discharge coefficient. For circumferential breaks, the discharge coefficient has a value of 1.0. For longitudinal breaks, the discharge coefficient is determined by the postulated break opening geometry for each case and is not greater than 0.85.

If a whipping pipe was capable of impacting adjacent pipes of equal or greater nominal pipe size and equal or heavier wall thickness, the adjacent pipe was considered to be free from rupture. Protection from pipe wall whip was not provided if pipe rupture occurred in such manner that the unrestrained pipe movement of either end of the ruptured pipe, in any possible direction about a plastic hinge formed at the nearest pipe whip restraint, cannot impact any structure, system or component required to survive the accident.

Piping that is physically separated or isolated from safety related structures, systems or components was excluded from the analysis. The physical separation or isolation may take the form of distance, protective barriers or pipe restraints designed specifically for pipe whip.

The restraints installed on the high energy piping systems preclude any functional damage to the Containment, Shield Building or other structures containing required equipment.

Compartment Pressure Loading and Stress

Compartment differential pressure loading from design basis breaks is determined from the mass-energy flow rates, from either a single ended or double ended break, the building compartment characteristics (volumes, heat sink surface areas, vent paths, etc.) and the postulated break locations.

To evaluate the capability of the compartment (walls, floors, etc.) to withstand pipe rupture pressures, the Working Stress Design methodology was chosen over other American Concrete Institute (ACI) [Ref. 15] approved methods of analysis to maintain consistence with USAR Section 12. At maximum allowable compartment stresses following a pipe

rupture ($f_c = 0.85\ f'_c$ for concrete compression and $f_s = 0.90\ f_y$ for steel tension), the actual stress distribution is nonlinear. For ultimate strength design, the ACI code's 1963 and 1971 editions favor Whitney's rectangular concrete stress distribution over Stucci's nonlinear stress distribution.

A comparison of Working Stress Design with Load Factors and Whitney's stress block for ultimate strength design proved favorable, thus indicating the adequacy of the Working Stress Design method for use in evaluation of concrete elements at pipe failure.

Jet Impingement

Jet Impingement loading on structures, systems or components required for design basis breaks or leakage cracks is determined from the magnitude and area of influence of the jet for each break based on the break size, orientation and fluid conditions. The jet forces at the point of rupture are consistent with those used in the pipe whip analysis and are based on the fluid pressure and temperature conditions occurring during normal plant operating modes. Jet loadings are not considered to vary with time, but are conservatively based on the initial conditions at the time of rupture.

Concrete (Punching) Shear Stress

The allowable stresses for shear, bond, etc., are determined from the accident/normal stress ratios associated with the compressive and tensile allowables. The accident/normal stress ratio for A615 reinforcing steel [Ref. 16] is $0.9f_y/0.5f_y = 1.8$ and the accident/normal allowable stress ratio for concrete is $0.86f_y/0.45f_c' = 1.89$. Using 1.8 as the ratio for both concrete and steel maintains ductility within the concrete element, since steel is the governing material. The allowable accident stress for (punching) shear during a pipe rupture is therefore 1.8 times the normal provisions of ACI 318-63 Section 1207 [Ref. 15].

The dynamic forces associated with the jets are evaluated with respect to their distance and spread from the pipe separation or crack. The jet geometry, where it impacts a concrete wall, is normally ellipsoidal and its perimeter defines the (punching) shear area. The magnitude of the jet force and area of loading is compared to the (punching) shear capacity. Where shear is found to be adequate, the concrete element is checked for other possible modes of stress or failure.

Jet Erosion of Concrete

The erosion of concrete by fluid jets is evaluated in WCAP-7391, "Pressurized Water and Steam Jet Effects on Concrete" by Westinghouse Atomic Power Division [Ref. 12]. To summarize the tests, five reinforced concrete beams were subjected to steam jets with nozzle diameters of 1, 2 and 4 inches. The distances investigated between nozzles and beams were 1 foot and 4 feet and the initial system pressure was 2250 psi. The results are as follows:

The erosion under all beam tests was observed to be (at most) 30 mils of surface paste removal, with no significant loss of either fine or coarse aggregate. The resultant surfaces

showed the same appearance as would be present after light sandblasting. It is concluded that short term erosion of concrete surfaces as a result of a high energy line break is not a design consideration.

I.2.2 Mitigating Consequences of Pipe Rupture

Pipe Restraints

Piping restraints are installed on high energy piping systems based on the identification of break locations selected in accordance with the criteria in the Giambusso letter [Ref. 1]. The piping restraints are designed to accommodate the loading induced by the reaction or whipping forces from the postulated design basis breaks. For a specific break location the pipe restraint accommodates a longitudinal break extending one pipe diameter on each side of the identified pipe stress node location or a circumferential break at the identified pipe stress node location.

Application of the GL 87-11 [Ref. 4] break selection criteria eliminated all high energy line design basis break locations outside containment except the terminal ends, intermediate anchors and identified branch connections.

Structural Components

Design Class I structures are reviewed for their adequacy to withstand the effects of postulated high energy pipe breaks. This analysis considers the effects of pressure and temperature transients and the static, thermal and dynamic reactions of the pipe in conjunction with the applicable loads listed in USAR Section 12.

Design Class I structural elements, such as floors, interior walls, exterior walls, building penetrations and the building as a whole, are analyzed for eventual reversal of loads due to a postulated design basis break.

Guard Pipes

Two types of "guard pipes" are used:

1. Encapsulation sleeves are installed to reduce the mass-energy released by the postulated break to limit the pressure build-up in the various Auxiliary Building compartments.

   The inside diameter of a main steam encapsulation sleeve is designed to be 3/4" greater than the outside diameter of the process pipe yielding an annular gap of 3/8" circumferentially. This produces an escape vent area of 36 in^2 per open end for the 30" main steam line. Due to the internal geometry of the encapsulation sleeve at the tee to the safety valve riser (three open ends), the effective annular vent area is the same as an encapsulated sleeve with two open ends [Ref. 9.1]. Application of GL 87-11 criteria eliminated these tees as break locations.

Peak containment pressure from a main steam line break is below the containment design rating, therefore, no encapsulation sleeves are installed in Containment. Since the mass-energy release from the postulated main steam breaks (selection based on the Giambusso letter) was significantly larger than the other high energy lines, encapsulation sleeves were only installed on main steam piping.

Application of the GL 87-11 [Ref. 4] break selection criteria eliminated all high energy line design basis break locations outside containment except the terminal ends of the turbine and identified branch connections. None of the branch connections required installation of an encapsulation sleeve [Ref. 9.4 and 9.9].

The following requirements [Ref. 10] are applicable to the design and support of encapsulation sleeves at design basis break locations:

a. The encapsulation sleeve is designed to fit closely around the process pipe in a manner that does not introduce significant strain concentrations on the encapsulated portion of the process pipe. The weight of the encapsulation sleeve is added to the mass of the process pipe in the pipe stress analysis and is supported by the process pipe's support system.

b. The encapsulation sleeve is designed, constructed and tested in accordance with the requirements of ASME Section III, for Code Class 2 components [Ref. 13] with the added requirement that every other pass of the final assembly welds are non-destructively examined by surface examination techniques (i.e., liquid penetrant or magnetic particle). The stresses imposed are limited to those associated with "emergency conditions."

c. The encapsulation sleeve is designed to withstand the dynamic forces of internal pressurization resulting from the escape of high energy fluid at the postulated pipe break location assuming complete pipe severance and axial separation to the extend permitted by the pipe restraints or a longitudinal break as defined in Section I.2.1.

d. The piping beyond the encapsulation sleeve is provided with pipe whip restraints (or anchors) which restrict its axial displacement and motion within the sleeve following a postulated circumferential pipe break.

e. The encapsulation sleeve extends for a minimum distance of two pipe diameters on either side of the design basis break location.

f. The encapsulation sleeve is designed to allow normal thread expansion movement of the process pipe and is not welded to the process pipe.

g. The materials are ASTM A-516 Grade 70 plate, A-106 Grade B pipe and A-234 Grade WPB fittings [Ref. 16].

h. The encapsulation sleeve is provided with open vent and drain pipe nipples which extend beyond the pipe insulation as a means of monitoring the encapsulated process pipe section for any leaks that might develop in service.

i. The design of the encapsulation sleeve permits either its removal by machining or flame cutting for the replacement of the encapsulated process pipe section in the event leaks develop.

2. Impingement barriers are installed to protect a structure, system or component by deflecting the high energy fluid jet generated by the postulated break or crack. Application of the GL 87-11 leakage crack location selection criteria eliminated the need for most of these installations.

The following requirements [Ref. 11] are applicable to the design and support of impingement barriers at design basis break and crack locations:

a. The impingement barrier is designed in a manner which does not introduce significant strain concentrations on the process pipe and is supported independently of the process pipe.

b. The impingement barrier is designed, constructed and tested as a Design Class I structure in accordance with the rules and practices set forth in the following codes:

Code For Welding In Building Construction, AWS D1.1-72, American Welding Society [Ref. 17].

Specification For The Design, Fabrication And Erection Of Structural Steel For Buildings, American Institute Of Steel Construction [Ref. 18].

c. The impingement barrier is designed to normal working loads and internal pressurization resulting from the escape of high energy fluid at the postulated pipe break location assuming complete pipe severance and axial separation to the extent permitted by the pipe restraints or a longitudinal break/crack as defined in Section I.2.1.

d. The stresses imposed on the impingement barrier during dynamic pressurization are limited to:

Membrane stresses produced by pressure existing in the impingement barrier are $\leq 0.90\ f_y$ and

Membrane stresses and peak bending stresses of short duration in the initial stage of pressurization $\leq 1.5 \times 0.9\ f_y$.

e. The piping beyond the impingement barrier is provided with pipe restraints which restrict its axial displacement and motion within the impingement barrier following a postulated pipe break.

f. The impingement barrier is a Design Class I structure and the materials are ASTM A-572 (various type/grades), A-516 Grade 70 plate, A-106 Grade B pipe and A-234 Grade WPB fittings [Ref. 16].

Steam Exclusion Boundary

To protect the systems and components required to detect and mitigate the consequences of a high energy line break, steam exclusion boundaries are created to isolate this equipment from those areas containing high energy piping systems or are connected to their potentially harsh environment. These boundaries include the walls, floors, ceilings and doors plus any penetrations of these barriers, such as ventilation systems, cables, cable trays and piping systems.

Areas that house required equipment, but do not contain high energy piping systems and are not connected to areas that might contain a harsh environment are not provided with steam exclusion boundary functions, although they are considered to be steam exclusion areas.

The steam exclusion boundaries are designed for the peak pressure and temperature conditions they are expected to encounter and limit the harsh environment intrusion into the steam exclusion area.

Pre-Service and In-Service Inspection

Pipe welds located within an encapsulation sleeve or impingement barrier and, therefore, not accessible for subsequent in-service inspection were non-destructively examined and satisfy the acceptance criteria of ASME Section XI [Ref. 13].

Pipe welds which are not located within an encapsulation sleeve or impingement barrier and are in the piping runs traversing the Auxiliary Building are subjected to periodic in-service examination in accordance with the ASME Section XI (edition currently invoked by the Prairie Island In-Service Inspection Program) requirements for Code Class 2 piping welds [Ref. 13]. The inaccessible welds are included in the total number of welds in determining the number of welds to be inspected in each inspection interval.

I.2.3 Plant Operability

Control Room Habitability

The Control Room is maintained habitable and the equipment required for a specific high energy line break remains functional for all high energy line design basis breaks or leakage cracks with the capability to bring the reactor to a cold shutdown condition from there.

Operation of Required Equipment

Electrical equipment that is required for a high energy line design basis break or leakage crack and can be affected by the harsh environment is qualified to perform their intended function in that environment.

Electrical equipment that is not qualified to operate in a harsh environment is located in a steam exclusion area created for that purpose.

Redundancy and Separation

Redundancy of required equipment for a specific high energy line design basis break or leakage crack is maintained in the mechanical components, protection systems (as defined in IEEE-279 [Ref. 19]) and Class 1 electrical systems (as defined in IEEE-308 [Ref. 20]).

The design considers environmentally induced failures caused by a break or leak which would not in itself result in protective action, but may disable a protective function. In this regard, a loss of redundancy is permitted, but a loss of function is not. The capability to bring the plant to cold shutdown is maintained.

The separation criteria for cables associated with the required equipment is identical to that described in USAR Section 8.7.

Operating Procedures

Operating procedures allow for evaluation of the specific high energy line break conditions and determination of appropriate actions to be taken to achieve cold shutdown. Prompt achievement and maintenance of hot shutdown is assured by automatic reactor protection functions or by operator action. The operator will determine which specific plant procedure will be used for placing the reactor in cold shutdown, based on the equipment available.

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I.3 SYSTEM ROUTING AND RUPTURE EVALUATION OUTSIDE CONTAINMENT

I.3.1 Structures

I.3.1.1 Description of Auxiliary Building

The part of the Auxiliary Building through which the high energy piping systems pass is a Design Class I seismic, concrete structure with tornado resistant outer walls and internal shielding walls. The Auxiliary Building is structurally divided into compartments by the walls and floors required to accommodate the equipment and components of various systems. With the exception of the compartments on elevation 695', the relay room, control room and mechanical equipment rooms, these volumes are vented to each other through corridors, grating openings, stairways, etc. Figure I.3.1-1 depicts an exploded view of the major compartments, while Figures I.3.1-2 through I.3.1-6 describe the boundaries of the individual compartments. The important parameters for the major compartments are provided in Table I.3.1-1.

I.3.1.2 Description of Turbine Building

The Turbine Building is a structure with mixed design classification. The Design Class I* steel structure provides a weather-proof enclosure for the turbine-generator and secondary plant auxiliary equipment. Also included within the steel structure is a Design Class I concrete structure (the Class I aisle) that houses safety related components. There are no high energy piping systems within the Class I aisle and it is designed as a steam exclusion area. The remainder of the Turbine Building areas are vented to each other through corridors, grating openings, stairways, etc.

I.3.2 High Energy Piping Systems

I.3.2.1 Main Steam

Routing

The main steam piping from steam generator 11 (21) exits the top of the steam generator and runs horizontally through a flow limiter. It then drops vertically to an anchor elbow before exiting Containment. The main steam line exits from the southwest (southeast) quadrant of Containment on Auxiliary Building elevation 715' (compartment Y) and enters the main steam isolation valve (MSIV) stop check - check valve assembly and concrete anchor block. The pipe then rises to elevation 735' (compartment X) where it turns northward and runs horizontally through the Auxiliary Building into the Turbine Building. It then drops vertically to elevation 715', turns northward before rising vertically back to elevation 735' and connects to the turbine nozzle. The main steam piping from steam generator 12 (22) exits the top of the steam generator and runs horizontally through a flow limiter. It then drops vertically to an anchor elbow before exiting Containment. The main steam line exits from the northwest (northeast) quadrant of Containment on Auxiliary Building elevation 715' (compartment C) and rises vertically to elevation 735'

(compartment B) where the MSIV assembly and concrete anchor block are located. The pipe then turns northward and runs horizontally parallel to steam line 11 (21) through the Auxiliary Building into the Turbine Building following a path similar to steam line 11 (21) to the turbine. At no point do any of the main steam lines enter the Design Class I portion of the Turbine Building.

These routings are shown isometrically on Figures I.3.2-1 (Unit 1) and I.3.2-2 (Unit 2), which also show connections to the safety valve header, steam dump to atmosphere header and equalizing line.

Pipe Rupture Evaluation

The original selection of break and branch connection locations based on the Giambusso letters is shown on FSAR Figures I.3-2 and I.3-3 (Unit 1 only). Cracks were assumed to occur at any location along the pipe. The stresses for the main steam piping were calculated as described in FSAR Section I.9 and depicted on Figures I.9-1 through I.9-4 and I.9-10 through I.9-14.

Postulated break, branch connection and leakage crack locations [Ref. 9.4], selected based on the GL 87-11 criteria, are shown on USAR Figures I.3.2-1 (Unit 1) and I.3.2-2 (Unit 2). The stresses for the main steam piping were calculated as described in Sections I.5.1 and are depicted on Figures I.5.1-1 through I.5.1-4.

At no point does the stress exceed the design basis break criteria, but there are several locations on the main steam lines that exceed the leakage crack criteria. Branch connections, which are considered the terminal end of the branch runs, exist at the steam supply to the auxiliary feedwater pump turbine, power operated relief valves and steam supply to the moisture separator reheaters. The risers to the safety valve header and steam dump headers are not considered branch connections in accordance with the GL 87-11 criteria (MEB 3-1, B.1.c.(1).(a)). The main steam line terminal ends are the steam generator nozzle connections, anchor elbows in Containment and the turbine nozzle connections. In accordance with GL 87-11 criteria only circumferential breaks are postulated at the terminal ends. A summary of the break, crack, intermediate anchor and terminal end locations is included as Table I.3.2-1. In addition, a summary for each Auxiliary Building compartment is included as Table I.3.2-3.

I.3.2.2 Feedwater

Routing

The discharge of each main feedwater pump (Turbine Building elevation 695') is routed through a check valve, motor operated valve and feedwater heater (elevation 715') before joining in the Turbine Building into a single line. Before entering the Auxiliary Building, the common feedwater line bifurcates into two lines - one for each steam generator. At no point do any of the feedwater lines enter the Design Class I portion of the Turbine Building. The line to steam generator 11 (21) enters the Auxiliary Building on elevation 735' (compartment B) running in a southerly direction parallel to main steam line 11 (21) (to

compartment X), before entering Containment in the southwest (southeast) quadrant. The feedwater line runs horizontally to an anchor elbow and then rises vertically through an expansion loop and check valve before turning horizontal to connect to the steam generator. The line to steam generator 12 (22) enters the Auxiliary Building on elevation 735' (compartment B) running in a southerly direction parallel to main steam line 12 (22), before entering Containment in the northwest (northeast) quadrant. The feedwater line runs horizontally to an anchor elbow and check valve before turning horizontal to connect to the steam generator. Each line is provided with a flow nozzle, control valves, concrete anchor block and motor operated isolation valve before entering Containment.

These routings are shown isometrically on Figures I.3.2-3 (Unit 1) and I.3.2-4 (Unit 2), which also shows the branch connections for the main control valve bypass lines.

Pipe Rupture Evaluation

The original selection of break and branch connection locations based on the Giambusso letters is shown on FSAR Figures I.4-1 and I.4-2 (Unit 1 only). Cracks were assumed to occur at any location along the pipe. The stresses for the main feedwater piping were calculated as described in FSAR Section I.9.1 and depicted on Figures I.9-5 through I.9-9.

Postulated break, branch connection and leakage crack locations [Ref. 9.4], based on the GL 87-11 criteria, are shown on Figures I.3.2-3 (Unit 1) and I.3.2-4 (Unit 2). The stresses for the feedwater piping were calculated as described in Section I.5.1 and depicted on Figures I.5.1-5 through I.5.1-8.

At no point outside containment does the stress exceed the design basis break or leakage crack criteria. No branch connections, which are considered the terminal ends of the branch runs, exist on the main feedwater lines outside containment. The feedwater line terminal ends are the steam generator nozzle connections and anchor elbows in Containment and the feedwater heater outlet nozzles in the Turbine Building. In accordance with GL 87-11 criteria only circumferential breaks are postulated at the terminal ends. A summary of the break, crack and terminal end locations for each feedwater line is included as Table I.3.2-1. In addition, a summary of each Auxiliary Building compartment is included as Table I.3.2-3.

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I.3.2.3 CVCS Letdown

Routing

The CVCS letdown line exits from the northwest (northeast) quadrant of containment into the Auxiliary Building through a penetration on elevation 715' (compartment D). The line is provided with an isolation valve adjacent to its penetration as well as isolation valves inside containment. The letdown line is then routed in a northerly direction to the letdown heat exchanger (compartment L).

These routings are shown isometrically on Figures I.3.2-5 (Unit 1) and I.3.2-6 (Unit 2).

Pipe Rupture Evaluation

The original selection of break and branch connection locations based on the Giambusso letters is shown on FSAR Figures I.5-1 and I.5-2 (Unit 1 only). Cracks were assumed to occur at any location along the pipe. The stresses for the CVCS letdown piping were calculated as described in FSAR Section I.9 and depicted on Figures I.9-15 and I.9-16.

At no point does the stress exceed the design basis break or leakage crack criteria. There are no branch connections. The CVCS letdown line terminal ends are the containment penetration and the letdown heat exchanger inlet nozzle. There is one intermediate anchor in each letdown line. In accordance with GL 87-11 criteria only circumferential breaks are postulated at the terminal ends and intermediate anchors. A summary of the break, crack and terminal end locations for each letdown line is included as Table I.3.2-1. In addition, a summary of each Auxiliary Building compartment is included as Table I.3.2-3.

Postulated terminal end break, intermediate anchor break and leakage crack locations, based on the GL 87-11 criteria, are shown on Figures I.3.2-5 (Unit 1) and I.3.2-6 (Unit 2). The stresses for the CVCS letdown line piping were calculated as described in Sections I.5-1 and depicted on Figures I.5.1-9 and I.5.1-10.

I.3.2.4 Steam Generator Blowdown

Routing

The steam generator blowdown lines exit from the northwest (northeast) quadrant of Containment into the Auxiliary Building through a penetration on elevation 715' (compartment D). Each line is provided with an isolation valve adjacent to its penetration as well as an isolation valve inside Containment. The blowdown line is then routed in a southerly direction to the blowdown flash tank (compartment D).

These routings are shown isometrically on Figures I.3.2-7 (Unit 1) and I.3.2-8 (Unit 2).

Pipe Rupture Evaluation

The original selection of break and branch connection locations based on the Giambusso letters is shown on FSAR Figures I.6-1 and I.6-2 (Unit 1 only). Cracks were assumed to occur at any location along the pipe. The stresses for the steam generator blowdown piping were calculated as described in FSAR Section I.9 and depicted on Figures I.9-21 through I.9-24.

At no point does the stress exceed the break criteria, but there are several locations that exceed the leakage crack criteria. There are no branch connections. The steam generator blowdown line terminal ends are the containment penetration and the steam generator blowdown flash tank inlet nozzles. There are two intermediate anchors in the #11 and #12 blowdown lines, one intermediate anchor in the #21 blowdown line and no intermediate anchor in the #22 blowdown line. In accordance with GL 87-11 criteria only circumferential breaks are postulated at the terminal ends and intermediate anchors. A

summary of the break, crack and terminal end locations for each steam generator blowdown line is included as Table I.3.2-1. In addition, a summary of each Auxiliary Building compartment is included as Table I.3.2-3.

Postulated terminal end break and intermediate anchor break locations, based on the GL 87-11 criteria, are shown on Figures I.3.2-7 (Unit 1) and I.3.2-8 (Unit 2). The stresses for the steam generator blowdown line piping were calculated as described in Section I.5.1 and depicted on Figures I.5.1-11 through I.5.1-14.

I.3.2.5 Steam Supply to Auxiliary Feedwater Pump Turbine

Routing

The steam supply line to the auxiliary feedwater pump turbine from steam generator 11 (21) originates on elevation 735' (compartment X) at branch connection from the safety valve header upstream of the main steam isolation valves. The line is routed in a northerly direction through the Auxiliary Building and joins the supply line from steam generator 12 (22) (compartment B). The common supply line proceeds down to elevation 695' (compartment E) and into the Turbine Building. The steam supply line from steam generator 12 (22) originates on elevation 735' (compartment B) at a branch connection from the main steam line upstream of the main steam isolation valves. The stop valves in the steam supply line to the auxiliary feedwater pump turbine were relocated outside of the auxiliary feedwater pump room. These valves are normally closed and receive a signal to open when the pumps are started. The piping in the room is normally depressurized and the room is considered to be a mild environment for the equipment contained therein [Ref. 6 & 7].

These routings are shown isometrically on Figures I.3.2-9 (Unit 1) and I.3.2-10 (Unit 2).

Pipe Rupture Evaluation

The original selection of break and branch connection locations based on the Giambusso letters is shown on FSAR Figures I.7-1 and I.7-2 (Unit 1 only). Cracks were assumed to occur at any location along the pipe. The stresses for the steam supply to the auxiliary feedwater pump turbine piping were calculated as described in FSAR Section I.9 and depicted on Figures I.9-17 through I.9-20.

At no point does the stress exceed the design basis break criteria, but there are several locations that exceed the leakage crack criteria. There are no branch connections. The steam supply to the auxiliary feedwater pump turbine line terminal ends are the branch connections from the main steam lines and safety valve headers and an anchor in the Turbine Building down stream of the control valves. There is one intermediate anchor in the line from #11 steam generator and no intermediate anchors in the lines from #12, #21 and #22 steam generators. In accordance with GL 87-11 criteria only circumferential breaks are postulated at the terminal ends and intermediate anchor. A summary of the break, crack and terminal end locations for each supply line is included as Table I.3.2-1. In addition, a summary of each Auxiliary Building compartment is included as Table I.3.2-3.

Postulated terminal end break and intermediate anchor break locations, based on the GL 87-11 criteria, are shown on Figures I.3.2-9 (Unit 1) and I.3.2-10 (Unit 2). The stresses for the steam supply to the auxiliary feedwater pump turbine line piping were calculated as described in Section I.5.1 and depicted on Figures I.5.1-15 through I.5.1-18.

I.4 FEATURES PROVIDED FOR PIPE RUPTURE EVENTS

I.4.1 Required Equipment

The equipment required to detect and mitigate the consequences of a high energy line design basis break or leakage crack and accomplish those functions identified in Section I.1.4 is summarized in Table I.1.4-1 [Ref. 9.6].

I.4.2 Steam Exclusion Boundaries

The various steam exclusion areas created include the Auxiliary Building elevation 695', Relay Room, Control Room, Control Room Ventilation Equipment Rooms, Unit 1 480v Bus and Events Monitoring Rooms, Control Rod Drive Equipment Rooms, Design Class I portion of the Turbine Building and Diesel Generator Rooms. Areas that do not contain high energy piping systems and are not connected to areas that might contain a harsh environment, such as the Screenhouse, are not provided with steam exclusion functions.

Walls, Floors and Ceilings

The steam exclusion areas are bounded by concrete (or masonry) walls, floors and ceilings. All penetrations are sealed to prevent intrusion of a harsh environment. The Auxiliary Building stairwells connecting elevation 715' to 695' are enclosed in masonry structures. All boundaries are designed to accommodate the maximum differential pressure expected.

Doors

Doors that form part of the steam exclusion boundary in either the Auxiliary Building or Turbine Building are provided with seals to preclude entry of a harsh environment. With the exception of the Control Room Ventilation Equipment Room doors, all of these doors are oriented such that they close against bar stops under the harsh environment pressure. The Control Room Ventilation Equipment Room doors are held closed by their latch mechanisms. Four sets of doors from the Auxiliary Building (elevations 720', 735' and 755') to the Fuel Handling Building will open at 0.2 psid during a high energy line break providing a vent path for building pressure relief [Ref. 9.11]. Typical door seals are shown on Figure I.4.3-2.

Ventilation

The ventilation systems serving the Relay Room, Control Room, Control Room Ventilation Equipment Rooms, Auxiliary Building elevation 695' and Design Class I portion of the Turbine Building are provided with redundant dampers that are closed by resistance temperature detectors (RTDs) located in their respective ductwork. The RTDs for these dampers are set at less than 120°F.

The ventilation system Steam Exclusion Actuation System consists of redundant RTDs, resistance to current converter, trip unit with isolation amplifiers plus indicators and recorders. Any one RTD will close the dampers in that train for the associated building.

There are 14 control and 14 check dampers located in the Auxiliary Building and Control Room ventilation systems plus 12 control and 12 check dampers in the Turbine Building ventilation system. The steam exclusion dampers and the ductwork between the wall and outermost damper are seismic Design Class I. The dampers originally installed were tested to a static pressure of 5 psi without the loss of functional operation. The maximum leakage acceptable on these dampers is 50 cfm at 0.5 psi. All dampers originally installed were tested at a differential pressure of 0.5 psi and the maximum leakage measured by the manufacturer was 30 cfm. These pressure values were based on preliminary compartment "X" and "Y" pressure analysis prior to installation of the flow limiting encapsulation sleeves. Although later compartment pressure analysis [Ref. 9.11] yielded lower values, replacement dampers for the Auxiliary Building are procured and tested to 50 cfm at 0.5 psi. Replacement dampers for the Turbine Building are procured and tested to 50 cfm at 0.25 psi.

Control and check dampers are tested for operability and the mating surfaces are visually inspected as required by the plant's Technical Specifications.

The Control Room has its own independent outside make-up air supply. Air is supplied through the Auxiliary Building roof at column rows G-6 (Unit 1) and H-14 (Unit 2) into elevation 755' (compartment A) and ducted to the Control Room Ventilation Equipment Room through redundant steam exclusion dampers. The air is cooled, if necessary, filtered, humidified and ducted through the floor into the Control Room. This system is described in more detail in Section 10.3.3.

The Control Room is automatically isolated from any adverse environment created by a high energy line break or crack by closure of the redundant steam exclusion dampers. Redundant fans and air conditioning systems maintain the Control Room habitable with regard to temperature, humidity and airborne radioactivity.

An analysis [Ref. 9.13] was performed to determine the environmental conditions on Auxiliary Building elevation 695' in the unlikely event that both sets of steam exclusion control dampers in the ventilation supply duct failed to close or the entering steam-air mixture temperature was below the steam exclusion actuation setpoint. The steam exclusion check dampers in the ventilation return ducts would prevent backflow into elevation 695' from the other Auxiliary Building compartments. This analysis demonstrated that the resultant temperatures on elevation 695' remained below the environmental qualification of the required equipment.

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Shield Building Seals

Bellows (similar to those used on the penetrations from the Auxiliary Building to the Shield Building annulus) have been tested [Ref. 22] at the Kewaunee Nuclear Power Plant. These tests showed that, with differential pressures of up to 20 psi internally, no rupture occurred. Tests with external pressurization equal to 50% of the internal differential pressure loadings were also conducted without any failure. The maximum calculated external pressure difference these bellows would be required to withstand is less than 0.3 psi for less than 2 minutes. The maximum calculated temperature these bellows would be exposed to during this time period is 300°F. The typical tensile strength of this material is 1443 psi with a temperature capability up to 325°F.

I.4.3 Encapsulation Sleeves and Impingement Barriers

Based on the break location and size criteria in the Giambusso letters, design basis breaks and leakage cracks were postulated in the Containment, Auxiliary Building and Turbine Building. An analysis revealed that the Auxiliary Building did not have the capability to withstand the pressure resulting from a design basis main steam line break. Encapsulation sleeves were installed at all postulated design basis break locations in the Auxiliary Building to reduce the peak compartment pressure. The criteria for the design of the encapsulation sleeves is contained in Section I.2.2 and their location was described in FSAR Figure I.3-3 for Unit 1. Although not described in the FSAR, encapsulation sleeves were installed at the same locations on Unit 2. No encapsulation sleeves were required on the other high energy piping systems. Typical encapsulation sleeves are shown on Figure I.4.3-1.

Impingement barriers were installed to protect required equipment from the effects of high energy fluid jets. Those impingement barriers that were installed around the various high energy piping systems are identified on Figures I.3.2-1 through I.3.2-10. Other impingement barrier designs were used for local protection, such as flat steel plates, steel shapes, etc. Typical impingement barriers are shown on Figure I.4.3-1.

Application of the GL 87-11 break selection criteria eliminated all main steam and feedwater design basis breaks except those at the terminal ends and greatly reduced the locations for leakage cracks. This process eliminated the need for most of these encapsulation sleeves and impingement barriers. Therefore, many of the modifications previously installed may be removed or abandoned in place.

I.4.4 Rupture Restraints

Based on the pipe rupture analysis discussed in FSAR Section I.10 rupture restraints were added to the main steam and feedwater system piping. No new rupture restraints were required on the other high energy systems. Typical tie rod restraints are shown on Figure I.4.3-1.

Application of the GL 87-11 break selection criteria eliminated all main steam and feedwater design basis breaks except those at the terminal ends, thereby eliminating the

need for all other of these restraints. However, they may be removed or abandoned in place.

I.4.5 Equipment Environmental Qualification

Location of Required Equipment

The location of the equipment required to bring the reactors to a safe shutdown condition, after a high energy line break event, is described in Table I.1.4-1 and Figure I.3.1-1.

The safety injection and component cooling pumps for both units are located in a steam exclusion area on Auxiliary Building elevation 695' (compartment E). The auxiliary feedwater pumps and batteries for both units plus the Unit 1 4160/480v switchgear are located in a steam exclusion area in the Turbine Building Class I corridor. Diesel generators D1 and D2 (Unit 1), D5 and D6 (Unit 2), the Unit 2 4160/480v switchgear and the cooling water pumps for both units are located in compartments separated from those containing high energy piping systems. The control room/relay room ventilation system is located in a steam exclusion area on Auxiliary Building elevation 755' (compartment A). The reactor trip breakers for both units are located in steam exclusion areas on Auxiliary Building elevation 735' (Compartment B). The motor control centers/motor starters for all identified motor operated valves are located in one of the steam exclusion areas of the plant.

Equipment Qualification

All instrumentation and electrical equipment required for high energy line break events, that are located in a post-accident harsh environment, are qualified in accordance with the Equipment Qualification Final Rule, 10CFR50.49. The establishment, documentation, maintenance and guidance for these components is contained within the plant's Equipment Qualification (EQ) Program.

Ancillary equipment (e.g., cable, fuses, splices, terminations, etc.), associated with any required equipment, that is located in an area where a harsh environment might exist are qualified and configured for that environment in accordance with the plant's EQ program.

I.4.6 Operating Procedures

The operating procedures discussed below are general in nature since it is appropriate to allow the operator to assess the incident and determine the equipment available prior to initiating any action. The plant can achieve and maintain hot shutdown for an extended time by automatic reactor protection functions or operator action. Following the high energy line break, the operator would have alternate systems (residual heat removal, chemical and volume control, component cooling, etc.) available to facilitate an orderly shutdown of the reactor. The methods presented use equipment determined to be available following a high energy line break event. The operator would determine the appropriate methods for achieving cold shutdown based on the systems and components available.

Main Steam Design Basis Break

For a design basis break, safety injection would be initiated by either low pressurizer pressure or low steam line pressure in either steam line. The main steam isolation valves are designed to close on the coincidence of a safety injection signal with either high-high steam flow or high steam flow coincident with low-low T_{avg}. The safety injection signal would cause a reactor trip, isolate the main feedwater system, initiate containment isolation and start the auxiliary feedwater pumps.

Following initiation of safety injection, the safety injection pumps deliver highly concentrated boric acid from the boric acid storage tank to insert sufficient negative reactivity to bring the reactor to a cold shutdown condition. Following delivery of the highly concentrated boric acid, the safety injection pumps deliver borated water from the refueling water storage tank.

The following equipment will accomplish the required safety functions:

1. Safety injection to pump borated water into the core, thereby limiting the core power transient following the break and bringing the reactor to a subcritical condition.

2. Closure of the main steam isolation valves to limit the reactor coolant system cooldown.

3. Isolation of the main feedwater system: Sustained feedwater flow would cause additional cooldown and mass-energy release to the Auxiliary Building. A safety injection signal would close the main feedwater control valves, close the feedwater containment isolation valves and trip the main feedwater pumps, which closes the feedwater pump discharge valves.

4. Following a reactor trip, auxiliary feedwater is required in approximately 10 minutes to dissipate decay heat. At least one auxiliary feedwater pump is available to supply the intact steam generator. After the affected steam generator has emptied or the break has been isolated, the auxiliary feedwater system and main steam power operated relief valves provide heat removal capability for maintaining hot shutdown conditions.

Main Steam Leakage Crack

For a leakage crack in the main steam piping system (7.3 in^2) steam release for the hot shutdown condition is approximately 100 lbs/sec and for the full power condition, 80 lbs/sec or five percent and four percent of full load turbine steam flow, respectively. This would not be sufficient to cause an overpower reactor trip.

A leakage crack would result in a loss of water inventory in the secondary plant that would lower the level in the condenser hotwell from the normal operating level to the low level alarm setpoint. Should the operator fail to take action at this point, the loss of secondary inventory would continue until the condensate pumps tripped. The following table provides

the times involved if the leakage crack occurred at either hot shutdown or full power [Ref. 9.3]:

	Time in Minutes	
Hotwell Level	Hot Shutdown	Full Power
Normal operating level	0	0
Low alarm setpoint	9	11
Condensate pump trip	64	85

The following automatic actions occur following the condensate pump trip:

1. main feedwater pump trip on loss of condensate pumps or low feedwater pump suction pressure,

2. turbine trip on loss of main feedwater pumps if turbine latched,

3. reactor trip due to low-low steam generator level or turbine trip if power greater than 10% power,

4. auxiliary feedwater pump start on loss of main feedwater pumps or low-low steam generator level.

The auxiliary feedwater pumps would deliver water to the steam generators from the condensate storage tank or cooling water system. After the reactor trip, continued steam release from the crack would cool the reactor coolant system down slower than if the largest relief valve were open. If the steam leak were not isolated by manual main steam isolation valve closure cooldown would continue resulting in safety injection being initiated by low pressurizer pressure or low steam line pressure. The safety injection pumps deliver concentrated boric acid from the boric acid storage tanks to insert sufficient reactivity to bring the reactor to cold shutdown boron concentration. Each boric acid tank has sufficient capacity to provide the required amount, even it it is at the low level alarm point.

In the event of a leakage crack, the auxiliary feedwater system and steam dump system (power operated relief, atmospheric or condenser, depending on component availability) would be used to dissipate reactor decay heat and cool the plant to 350°F. The residual heat removal system would then normally be used to cool the plant to cold shutdown conditions.

Feedwater

For a feedwater line design basis break, the reactor is automatically tripped due to low-low steam generator level. The auxiliary feedwater system in conjunction with the steam generator safety valves and power operated relief valves provide the ultimate heat sink for the reactor coolant system for maintaining hot shutdown conditions. In order to take the reactor from hot shutdown to cold shutdown conditions, boron is added to achieve cold shutdown concentration. Additional water is added to replace the volume lost due to

shrinkage during cooldown. This can be accomplished by opening the pressurizer power operated relief valves to temporarily reduce reactor coolant system pressure below the safety injection pump shutoff head. After re-closing the pressurizer power operated relief valves, the auxiliary feedwater system and main steam power operated relief valves provide heat removal capability for maintaining hot shutdown conditions and cooling the reactor coolant system to 350°F.

If a rupture should occur in the feedwater line that would not directly cause a reactor trip, the operator has numerous devices (steam generator pressure, steam generator level, etc.) to detect such an event. The operator would assess the plant conditions (location of break, ability to isolate, equipment available, etc.) and determine actions to be taken. If necessary, the reactor could be shutdown by manually tripping the reactor or initiating safety injection which would trip the reactor, start the safety injection and auxiliary feedwater pumps and initiate containment isolation. The plant would remain in hot shutdown conditions until the appropriate method for going to cold shutdown was determined.

A feedwater system leakage crack would result in a loss of water inventory in the secondary plant in a manner similar to a main steam leakage crack.

Chemical & Volume Control System Letdown

For a design basis break or leakage crack in a CVCS letdown line the operator has numerous devices (pressurizer level, pressurizer pressure, area radiation monitors, etc.) to detect such an event. The break or crack would be terminated by closing the inside containment isolation valve in the affected line. This isolation could also be accomplished by closing either of the reactor coolant system loop isolation valves.

Steam Generator Blowdown

For a design basis break or leakage crack in a steam generator blowdown line the operator has numerous devices (steam generator level, feedwater flow, steam/feedwater flow deviation, etc.) to detect such an event. The break or crack would be terminated by closing one of the redundant motor operated containment isolation valves in the affected line.

Steam Supply To Auxiliary Feedwater Pump Turbine

A design basis break or leakage crack in the steam supply line to the auxiliary feedwater pump turbine would be similar to an unisolatable main steam line leakage crack if the steam supply isolation valve could not isolate the break.

Cold Shutdown

The plant is designed to achieve hot shutdown (automatically or by operator action) and maintain that condition for an extended time using the auxiliary feedwater system and main steam power operated relief valves for decay heat removal. The safety injection system

provides the boric acid for reactivity control and reactor control inventory make-up. After assessment of the event and evaluation of the equipment available, the operator would determine the most appropriate method and procedure for achieving cold shutdown. The auxiliary feedwater system and main steam power operated relief valves would be used to cool the plant to 350°F.

The residual heat removal system would normally (and preferentially) be used to reduce the reactor coolant system temperature to cold shutdown conditions. If the residual heat removal systems are not available, the auxiliary feedwater system and plant secondary side systems can be used to bring the reactor coolant system to cold shutdown conditions. However, this process would require a much longer time. This could be accomplished by converting a steam generator into a water to water heat exchanger by filling it with cold water from the auxiliary feedwater pumps. The warmer water could be discharged through a combination of the steam generator blowdown flash tank, main steam line traps and drains, main steam line power operated relief valve, steam dump to condenser, etc.

I.5 TOPICAL ANALYSIS

I.5.1 Pipe Stress

Stress analysis was performed on the five identified high energy piping systems using a computer program with the capability to analyze piping systems subjected to thermal expansion, pressure, weight, static seismic and dynamic seismic loading conditions. These analyses were performed in accordance with the requirements of the Power Piping Code (ANSI B31.1 - 1967). The program incorporated special conditions such as anchor movements, intermediate point forced movements, limit stops, external forces, rigid supports, restraints, etc. The combination of stresses due to pressure, thermal, weight and seismic loading conditions was also determined.

These stress analyses were utilized to determine the design basis break locations in accordance with the criteria contained in the Giambusso letters. They were presented graphically as FSAR Figures I.9-1 through 24. Based on these analyses, modifications (encapsulation sleeves, impingement barriers, etc.) were made to the plant.

Generic Letter 87-11 relaxed the requirements for selecting arbitrary intermediate break locations by utilizing threshold stress criteria based on the ASME Section III Code. The most recent analysis of record for the high energy piping systems was retrieved and the combined stresses recalculated by using the ASME stress indices instead of the ANSI stress intensification factors. The new combined stress was compared to the GL 87-11 criteria for selecting design basis break and leakage crack locations.

Application of the GL 87-11 selection criteria to high energy lines outside containment eliminated all arbitrary intermediate design basis breaks and reduced the number of leakage cracks to a few locations. Therefore, many of the modifications previously installed may be removed or abandoned in place.

I.5.2 Pipe Whip

Restraints are provided to prevent pipe whip where there is a possibility that whip following a pipe rupture would damage structures, systems or components that are required to mitigate the consequences of that pipe rupture.

A nonlinear elastic-plastic analysis [Ref. 21] is performed to evaluate the adequacy of the pipe rupture restraint system to provide protection following postulated circumferential and longitudinal pipe breaks. The coupled nonlinear dynamic analysis of the restraint-piping system accounts for the dynamic nature of the rupture force, the elastic-plastic deformation of the pipe restraint system and the impact between the restraint and pipe.

The results of the analysis include identification of plastic hinges formed in the pipe, strain in the hinges and restraint status, including gap closure, elastic or plastic deformation and reacting loads.

Blowdown Forces

Blowdown forces resulting from pipe rupture were originally determined using a computer program [Ref. 21] based on RELAP-3, the loss of coolant accident program accepted by the AEC at that time. The program computes and plots the force-time history curve of the reaction loads resulting from a circumferential or longitudinal pipe break subcooled liquid, flashing liquid and steam systems.

The system of interest is modeled as an assembly of volumes connected by flow paths. In a flow path there can be inserted a valve, check valve or pump. The program solves the transient energy, momentum and state equations for the volumes and flow paths. The program can also solve the state equation for subcooled water, two phase steam-water mixtures and superheated steam. The ASME Steam Tables are tabulated within the program and table lookup methods are used to determine the state within each volume. An optional bubble separation model can be used to represent a vapor phase above the liquid phase (e.g., steam generator). The program calculates the flow in each junction using both an inertial model (nonchoking) and a flow model (choking). The lower of the flows calculated from the two models is limiting and thus taken as the actual flow.

The program allows for special component characteristics as applicable in different systems. Leaks can open instantaneously or as a function of time. Pumps can continue to operate or coast down. Valves can be opened or closed and check valves follow a prescribed pressure loss, flow characteristic.

The break force is calculated using the one dimensional momentum equation. The resultant force on the broken piping is the algebraic sum of the following three forces:

Momentum flux

$$\rho \frac{AV^2}{g}$$

Momentum change (zero for steady state)

$$\frac{\Delta(mV)}{\Delta tg}$$

Pressure force (zero for non-choking flow)

$$(P_t - P_e)\, A$$

where: P_t = throat pressure
P_e = exit pressure
A = break area
ρ = density
V = velocity
g = acceleration of gravity
m = mass
t = time

The results of the analysis for the main steam and feedwater systems are presented in four Nuclear Services Corporation Topical Reports [Ref. 21].

Computation of piping system response to pipe rupture forces is determined with a computer program using an adaptation of the finite element method to the specific requirements of pipe rupture analysis. A dynamic response time history of the piping system is determined which includes elastic-plastic pipe behavior and nonlinear effects of pipe rupture restraints.

The piping system is modeled as an assemblage of straight and curved beams (elbows) connecting discrete nodal points. Weight of the piping system (including offset weights of valve operators) is "lumped" at selected nodal points. The blowdown force versus time history as developed by the previously discussed transient flow analysis computer program is then applied as an excitation force to the appropriate piping node point. Dynamic response of the piping system is computed at iterative increments of time and includes forces, moments, deflections and rotations at each node. The resulting bending and torsional moments at each node are used to predict both initial yielding (at which time the elastic modulus at the affected point is replaced by the strain hardening modulus) and ultimate load (i.e., formation of a plastic hinge, after which the modulus is set to a very low value). In situations where stress reversal occurs, an isotopic strain hardening model is used. The strain in plastic hinges and deflections of node points are used to identify the pipe trajectory.

Pipe rupture restraints are modeled with initial design gaps and then both elastic and plastic moduli. At each time step, the programs determine gap closure, elastic or plastic deformation and the resulting impact load.

A model of a typical main steam line is shown in Figure I.5.1-19.

I.5.3 Compartment Pressure and Temperature

The GOTHIC code was used to predict the pressure and temperature response of Auxiliary Building compartments to a high energy line break [Ref. 9.9, 9.10 and 9.11].

The analysis assumes that a high energy line break event can be separated into phases such that the result of the analysis of one phase serves as the conditions of the time dependent input to the next phase. The calculation accounts for the description of the high energy line blowdown characteristics, including the effects of steam superheating addressed in NRC Information Notice 84-90 [Ref. 5].

The blowdown rate and duration depend on the system operating conditions and break size. Only exposed concrete surface areas are considered as heat sinks. No credit is taken for heat removal capability of exposed steel, individual unit coolers or ventilation systems.

The Auxiliary Building compartment volumes are separated into a liquid and vapor region. Each region is assumed to have a uniform temperature, but the temperatures of the two

regions may be different. The Auxiliary Building is represented as a multi-compartment structure whose behavior can be described by the one dimensional, multi-region, heat conduction equation.

The calculation proceeds as follows: The initial compartment conditions are determined from ambient pressure (14.7 psia), temperature (130°F) and relative humidity (85%). All heat sinks are initially at 130°F. Time advancement is started by evaluating the fluid mass and energy input rates at the midpoint of a time interval, multiplying by the time interval and adding these increments to the current amounts in the compartment. Heat losses or gains to the heat conducting surfaces are estimated by using the heat transfer rates from the previous time step or the steady state conditions for the initial time step. Pressure and temperature of the liquid and vapor regions are then calculated from the mass, volume and energy balance equations. These new temperatures are used for the boundary conditions for the heat conduction solution. The resulting heat transfer rates for the end of the time step are averaged with the heat transfer rates at the beginning of the time step to correct the previous estimate of the energy in the compartment volume. Mass, momentum and energy equations are then solved for the second time for the pressure and temperatures within the compartment volume. These conditions are then used as the initial conditions for the next time step.

The GOTHIC code considers the opening (at 0.2 psid) of four sets of steam exclusion boundary doors from the Auxiliary Building (elevations 720', 735' and 755') to the Fuel Handling Building to provide a vent path for pressure relief. The pressure outside the Auxiliary Building is assumed to remain at 14.7 psia.

Calculations are performed for selected break sizes and locations at hot shutdown main steam conditions to obtain the peak compartment pressure and at full power main steam conditions to obtain the peak compartment temperature. The peak pressure and temperature for some of the compartments are as follows:

Compartment	Elevation	Peak Temp. °F	Peak Press. psig
A	755'	350	0.29
B	735'	363	0.25
C	715'	273	0.24
D	715'	325	0.37
X	735'	400	0.40
Y	720'	405	0.41

Elevation 695' of the Auxiliary Building and selected areas of the plant such as the Control Room, Relay Room and Mechanical Equipment Room are isolated from the effects of the high energy line break environment.

I.5.4 Jet Impingement [Ref. 9.7]

Jet-impingement load is defined as the force exerted on a component or structure from an undeflected fluid resulting from an instantaneous break or crack in a high-energy pipe.

Maximum impingement pressure along the jet centerline is determined using the ANSI/ANS-58.2-1988 [Ref. 23] standard on the effects of pipe rupture. This standard models jet-impingement load by dividing the expansion of the jet into three regions. Near the jet discharge there is a conical jet core region. The length of the core L_c is defined by the expression:

$$L_c/D_e = 0.26(\Delta T_{sub})^{1/2} + 0.5$$

where:

D_e = effective pipe break/crack diameter = $(4A_e/\pi)^{1/2}$
A_e = effective break/crack area
ΔT_{sub} = jet subcooling at stagnation conditions in °F at the point of rupture

The maximum impingement pressure and temperature along the jet centerline within this jet core are the system pressure and temperature, respectively, prior to pipe rupture.

In the second region, the jet outside the conical jet core undergoes free expansion to a static jet pressure P_a, which is related to jet stagnation quality and pressure and the ambient pressure in the subsonic portion of the jet. The area A_a of the jet at the point at which P_a is reached, called the asymptotic plane, is given by:

$$A_a = A_e(G_e^2/g_c)\ [v_a/(F/A_e)]$$

where:

G_e = critical exit mass flux from the rupture
v_a = specific volume of the two-phase mixture in the jet at a pressure of P_a
F = initial force at the point of rupture

Since depressurization out to the asymptotic plane is almost equal to the axial and radial directions, the jet expands with a jet half angle of 45 degrees out to the asymptotic plane.

In the third region the jet continues to expand after passing the asymptotic plane with a jet half angle of 10 degrees. The maximum impingement pressure P along the jet centerline is given by:

$$P = 3F/A$$

where:

A = area of the jet

The area A of the jet at some distance L_3 from the point of the break or crack is given by

$$A = [L_1/2 + L_3 \tan (\Phi/2)] [L_2/2 + L_3 \tan (\Phi/2)]\pi$$

where:

L_1 = width of break or crack
L_2 = length of break or crack
Φ = divergence angle

Φ is taken as 90° (i.e., a 45° half angle) from the point of rupture out to the asymptotic plane and 20° (i.e., a 10° half angle) beyond the asymptotic plane.

Jet centerline temperature outside the jet core region is taken as the saturation temperature at pressure P.

The average jet pressure at a distant target is:

$$P_I = P\ C_{ave}$$

where:

C_{ave} = averaging factor based on experimental velocity profiles (use 1.0, which is the worst case)

The effective load on a distant target is:

$$F_e = f\ P_i\ A_t$$

where:

A_t = projected area of the target object
f = shape factor to account for deflection, rather than stagnation, of the jet. The only value used is unity.

Typical targets are walls, cables, cable trays and instrumentation. Jet impingement loads on these potential targets are determined and, if necessary, barriers or other protection is installed to reduce the forces on the targets. Calculations show that the functions of cables

and cable trays are not affected by jet forces of 2 psi or less. The instrumentation and cables associated with the equipment required to bring the reactor to cold shutdown after a high energy line break are qualified for the resultant environment in accordance with the plant's EQ program. When the temperature of a high energy jet exceeds their qualification, jet impingement barriers are installed to protect them or they are relocated.

For each of the five identified high energy piping systems, pressure and temperature were calculated at various distances from postulated pipe breaks and cracks. Examples of the resulting curves appear in Figures I.5.4-1 through I.5.4-20.

I.5.5 Flooding [Ref. 9.12]

A review of non-Class I Piping systems in the Design Class I area of the Auxiliary Building identified the feedwater system and steam generator blowdown due to the high flow rates and the fire protection system due to its unlimited water supply to be the systems of concern for flooding. The potential effects from a break in any other non-Class I system are bounded by these systems. An analysis of these systems was performed. 00-298

In addition to flooding, the Auxiliary Building was also examined for any potential damage to the required equipment due to cascading water as it passes through floor openings (stairwells, pipe chases, floor drains, etc.) on its way to elevation 695'. Most of the required equipment is located on elevation 695', which is a steam exclusion area and all penetrations from elevation 715' are sealed. All water from the upper elevations would be directed through the floor drain system and not cascade on equipment located on elevation 695'.

The analysis concluded that the maximum postulated flood levels and cascading water in the Auxiliary Building are such that equipment required to mitigate a feedwater, blowdown or fire protection line break remain operable. 00-298

The routing and pipe rupture evaluation of the feedwater line, as described in Section I.3.2.2, revealed no design basis break or leakage crack locations in the main piping in the Auxiliary Building. The Unit 2 feedwater flow control by-pass lines (4") have several leakage crack locations as identified on Figure I.3.2-4. 00-298

The routing and pipe rupture evaluation of the steam generator blowdown line is described in Section I.3.2.4. Each 2" line has terminal end design basis break locations in the Auxiliary Building. These locations are identified on Figures I.3.2-7 and I.3.2-8. 00-298

Operator action was assumed within 15 minute to detect, identify and isolate the postulated 4" feedwater control valve by-pass line leakage cracks or 2" steam generator blowdown line design basis breaks. 00-298

For #21 feedwater flow control valve by-pass line leakage cracks, the water would flow down to elevation 723'-4" and spill over the fuel transfer canal into the steam generator blowdown flash tank and filter/demineralizer areas. Fire doors separating these areas from the remainder of the Auxiliary Building were conservatively assumed closed and any leakage was contained inside these areas before flowing through the floor drain system to the building sump. For #22 feedwater flow control by-pass line leakage cracks, the water would flow through floor openings and floor drains to the building sump. 00-298

Steam generator blowdown line design basis breaks occur in areas similar to those feedwater flow control by-pass line leakage cracks discussed above and flow to the building sump in a similar manner. 00-298

The fire protection system in the Auxiliary Building consists of a main 10" distribution ring header on elevation 735' and smaller headers and risers servicing the other building elevations. The plant response to a break in the fire protection system with its unlimited water supply, relies on operator action to isolate the break or stop the fire pumps.

Analyses have determined that water from design basis breaks and leakage cracks in the above systems could not reach a depth where it could disable required equipment in the Auxiliary Building. 00-298

I.6 MAIN STEAM AND FEEDWATER INSIDE CONTAINMENT

Although the December 1972 Giambusso letter only requested information concerning high energy line breaks outside Containment, a conservative engineering judgement was made to perform a similar review of the main steam and feedwater lines inside Containment utilizing the criteria from the Giambusso letters. However, the results of that review were not incorporated into the FSAR/USAR or addressed by the AEC Safety Evaluation Report.

The Containment is designed for the peak pressure resulting from the rupture of a main steam or feedwater line, therefore, no encapsulation sleeves to limit mass-energy release are required. To avoid jet impingement damage to required equipment, some instrumentation on the 11 (21) steam generator was relocated. Guard pipes were installed on portions of the main steam and feedwater lines associated with the 12 (22) steam generator. This was done to protect the cables in the electrical penetration area from the crack that was assumed to occur anywhere along the pipe and the arbitrary intermediate break locations. Application of the criteria contained in GL 87-11 eliminated all arbitrary intermediate break and leakage crack locations on the main steam lines and the need for the guard pipes and it eliminated most arbitrary intermediate breaks and leakage cracks on the feedwater lines. However, one intermediate break location on #22 steam generator feedwater line and some leakage crack locations on each feedwater line were identified. These break and crack locations and impingement barrier installations are depicted on Figures I.3.2-3 & 4 and Table I.3.2-2.

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I.7 REFERENCES

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2. Letter from USAEC (A Giambusso) to NSP (AV Dienhart) dated January 11, 1973.

3. Letter from USAEC (A Giambusso) to NSP (AV Dienhart) dated February 9, 1973.

4. USNRC Generic Letter 87-11, Relaxation In Arbitrary Intermediate Pipe Rupture Requirements, June 19, 1987.

5. USNRC Information Notice 84-90, Main Steam Line Break Effect on Environmental Qualification of Equipment, December 10, 1984.

6. Letter from USNRC (Dilanni) to NSP dated October 22, 1984, Summary of September 19, 1984, meeting with NSP Regarding the Resolution of Environmental Qualification of Equipment in the Auxiliary Feedwater Pump Room at PI 1&2.

7. Letter from NSP (Musolf) to USNRC (Director, NRR) dated November 28, 1984, Resolution of Environmental Qualification of Equipment in the Auxiliary Feedwater Pump Room.

8. Deleted

9. NSP Calculations

   9.1 ENG-ME-304, Main Steam Line Encapsulation Sleeve Vent Area

   9.2 ENG-ME-319, Feedwater System Piping Analysis

   9.3 ENG-ME-351, Depletion of Condenser Hotwell Inventory

   9.4 ENG-ME-357, Break Location Selection

   9.5 ENG-ME-358, Piping System Selection

   9.6 ENG-ME-360, Required Equipment Selection

   9.7 ENG-ME-369, Jet Impingement

   9.8 ENG-ME-400, Stress Plots For High Energy Piping Systems

   9.9 ENG-ME-127, Auxiliary Building HELB Compartment Volumes

   9.10 ENG-CS-141, Auxiliary Building HELB Surface Areas and Flow Paths

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9.11 NSPNAD 99006P, GOTHIC Results For High Energy Line Breaks In Prairie Island Auxiliary Building, Rev. 2, May, 2000

9.12 ENG-ME-448, Auxiliary Building Flooding Due to Pipe Cracks and Breaks.

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21. Nuclear Services Corporation, Topical Reports

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21.2 PI 0-01-24, Unit 2 - Pipe Rupture Analysis of Main Steam Piping Outside Containment.

21.3 PI 0-01-02, Unit 1 - Pipe Rupture Analysis of Feedwater Piping Outside Containment.

21.4 PI 0-01-27, Unit 2 - Pipe Rupture Analysis of Feedwater Piping Outside Containment.

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23. American National Standards Institute, ANSI/ANS 58.2, Design Basis For Protection Of Light Water Nuclear Power Plants Against Effects Of Postulated Pipe Rupture, October 6, 1988.

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TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
MECHANICAL							
034-011, 034-021	D1/D2 diesel generator	*	X	X	X	X	X
234-031, 234-032	D5/D6 diesel generator	*	X	X	X	X	X
045-591, 045-592	Chilled water pump	*	X	X	X	X	X
145-071, 145-072	Safety injection pump	*	X	X	X	X	X
245-071, 245-072	Safety injection pump	*	X	X	X	X	X
145-201, 145-331	Auxiliary feedwater pump	*	X	X	X	X	X
245-201, 245-331	Auxiliary feedwater pump	*	X	X	X	X	X
045-091	Cooling water pump	*	X	X	X	X	X
145-392, 245-392	Cooling water pump	*	X	X	X	X	X
145-121, 145-122	Component cooling pump	*	X	X	X	X	X
245-121, 245-122	Component cooling pump	*	X	X	X	X	X
145-261, 145-262	Feedwater pump	TB	X	X	X	X	X
245-261, 245-262	Feedwater pump	TB	X	X	X	X	X
045-271, 045-272	D1/2 fuel oil transfer pump	*	X	X	X	X	X
045-273, 045-274	D1/2 fuel oil transfer pump	*	X	X	X	X	X
045-301, 045-302	DDCLP fuel oil transfer pump	*	X	X	X	X	X
245-881, 245-882	D5/6 fuel oil transfer pump	*	X	X	X	X	X
245-883, 245-884	D5/6 fuel oil transfer pump	*	X	X	X	X	X
067-011, 067-012	Safeguard traveling screen	*	X	X	X	X	X
146-011, 246-011	DDCLP starting air receiver	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
MECHANICAL							
046-031, 046-032	D1/2 starting air receiver	*	X	X	X	X	X
246-031, 246-032	D5 starting air receiver	*	X	X	X	X	X
246-033, 246-034	D5 starting air receiver	*	X	X	X	X	X
246-035, 246-036	D6 starting air receiver	*	X	X	X	X	X
246-037, 246-038	D6 starting air receiver	*	X	X	X	X	X
158-011, 158-012	Cooling water strainer	*	X	X	X	X	X
258-011, 258-012	Cooling water strainer	*	X	X	X	X	X
032-041, 032-042	D1/D2 room supply fan	*	X	X	X	X	X
032-011, 032-012	D1/D2 room exhaust fan	*	X	X	X	X	X
032-291, 032-292	Control room clean-up fan	*	X	X	X	X	X
132-281, 232-281	DDCLP roof exhaust fan	*	X	X	X	X	X
076-021, 076-022	Control room air handler	*	X	X	X	X	X
232-441, 232-442	D5/D6 building supply fan	*	X	X	X	X	X
232-443, 232-444	D5/D6 building supply fan	*	X	X	X	X	X
232-451, 232-452	D5/D6 building exhaust fan	*	X	X	X	X	X
232-453, 232-454	D5/D5 building exhaust fan	*	X	X	X	X	X
232-421, 232-422	D5/D6 room cooling fan	*	X	X	X	X	X
074-031, 074-032	Relay room unit cooler	*	X	X	X	X	X
074-033, 074-034	Relay room unit cooler	*	X	X	X	X	X
174-031, 174-032	Bus 15/16 room unit cooler	*	X	X	X	X	X
274-031, 274-032	Bus 111/112 room unit cooler	*	X	X	X	X	X
174-161, 274-161	Bus 112/122 room unit cooler	*	X	X	X	X	X

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TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
MECHANICAL							
174-162, 274-162	EMA/B room unit cooler	*	X	X	X	X	X
174-163	EMA room unit cooler	*	X	X	X	X	X
075-011, 075-012	Control room chiller	*	X	X	X	X	X
CONTROL VALVE (CV-)							
31127, 31128	Feedwater flow - main	B/X	X	X	X	X	X
31135, 31136	Feedwater flow - main	B/X	X	X	X	X	X
31369, 31370	Feedwater flow - bypass	B/X	X	X	X	X	X
31371, 31372	Feedwater flow - bypass	B/X	X	X	X	X	X
31245, 31246	RCP thermal barrier return	*	X	X	X	X	X
31247, 31248	RCP thermal barrier return	*	X	X	X	X	X
31381, 31411	CC Hx cooling water outlet	*	X	X	X	X	X
31383, 31384	CC Hx cooling water outlet	*	X	X	X	X	X
31231, 31232	Pressurizer PORV	*	X	X	X	X	X
31233, 31234	Pressurizer PORV	*	X	X	X	X	X
31084, 31089	Steam generator PORV	A/X	X	X	X	X	X
31102, 31107	Steam generator PORV	A/X	X	X	X	X	X
31998, 31999	Steam supply to AFWPT	TB	X	X	X	X	X
31059, 31060	AFW Pump trip throttle	*	X	X	X	X	X
31153, 31154	AFW pump oil cooler	*	X	X	X	X	X
31418, 31419	AFW pump oil cooler	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

CONTROL VALVE (CV-)	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
31423, 31457	DDCLP jacket water cooler	*	X	X	X	X	X
31505, 31506	D1/D2 heat exchanger	*	X	X	X	X	X
31769, 31785	Control room chiller	*	X	X	X	X	X
31786, 31768	Control room air handler	*	X	X	X	X	X
31755, 31756	Bus 111/112 room unit cooler	*	X	X	X	X	X
31759, 31760	Relay room unit cooler	*	X	X	X	X	X
31761, 31762	Relay room unit cooler	*	X	X	X	X	X
31757, 31758	Bus 15/16 room unit cooler	*	X	X	X	X	X
31764, 31765	Bus 112/122 room unit cooler	*	X	X	X	X	X
31766, 31767	EMA/B room unit cooler	*	X	X	X	X	X
31788	EMA room unit cooler	*	X	X	X	X	X
31953, 31954	D1 starting air	*	X	X	X	X	X
31955, 31956	D2 starting air	*	X	X	X	X	X
31098, 31099	Containment isolation - MS	B/Y	X	X	X	X	X
31116, 31117	Containment isolation - MS	B/Y	X	X	X	X	X
31339, 31430	Containment isolation - VC	D	X	X	X	X	X
31325, 31347	Containment isolation - VC	*	X	X	X	X	X
31326, 31348	Containment isolation - VC	*	X	X	X	X	X
31327, 31349	Containment isolation - VC	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
SOLENOID VALVE (SV-)							
37903, 37904	D5 starting air	*	X	X	X	X	X
37906, 37907	D5 starting air	*	X	X	X	X	X
37933, 37934	D6 starting air	*	X	X	X	X	X
37936, 37937	D6 starting air	*	X	X	X	X	X
33464, 33465	12 DDCLP starting air	*	X	X	X	X	X
33466, 33467	22 DDCLP starting air	*	X	X	X	X	X
MOTOR VALVE (MV-)							
32016, 32017	Steam supply to AFWPT	B/X	X	X	X	X	X
32019, 32020	Steam supply to AFWPT	B/X	X	X	X	X	X
32025, 32027	AFW pump suction - CL	*	X	X	X	X	X
32026, 32030	AFW pump suction - CL	*	X	X	X	X	X
32031, 32033	CL header to Turb Bldg	*	X	X	X	X	X
32034, 32035	CL pump header isolation	*	X	X	X	X	X
32036, 32037	CL pump header isolation	*	X	X	X	X	X
32045, 32047	MSIV bypass	B/Y	X	X	X	X	X
32048, 32050	MSIV bypass	B/Y	X	X	X	X	X
32068, 32070	SI cold leg injection	*	X	X	X	X	X
32073, 32176	SI cold leg injection	*	X	X	X	X	X
32171, 32173	SI cold leg injection	*	X	X	X	X	X
32079, 32080	SI pump suction from RWST	*	X	X	X	X	X
32182, 32183	SI pump suction from RWST	*	X	X	X	X	X

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TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

MOTOR VALVE (MV-)	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
32081, 32082	SI pump suction from BAST	*	X	X	X	X	X
32184, 32185	SI pump suction from BAST	*	X	X	X	X	X
32083, 32186	SI pump suction from BAST	*	X	X	X	X	X
32089, 32091	RCP CC inlet	C	X	X	X	X	X
32124, 32126	RCP CC inlet	C	X	X	X	X	X
32090, 32092	RCP CC outlet	C	X	X	X	X	X
32125, 32127	RCP CC outlet	C	X	X	X	X	X
32120, 32121	CC Hx outlet crossover	*	X	X	X	X	X
32122, 32123	CC Hx outlet crossover	*	X	X	X	X	X
32145, 32146	Cooling water to CC Hx	*	X	X	X	X	X
32160, 32161	Cooling water to CC Hx	*	X	X	X	X	X
32144, 32159	Cooling water header crossover	*	X	X	X	X	X
32162, 32163	SI pump suction	*	X	X	X	X	X
32190, 32191	SI pump suction	*	X	X	X	X	X
32195, 32196	Pressurizer PORV isolation	*	X	X	X	X	X
32197, 32198	Pressurizer PORV isolation	*	X	X	X	X	X
32200, 32201	CC surge tank to pump	*	X	X	X	X	X
32211, 32212	CC surge tank to pump	*	X	X	X	X	X
32238, 32381	AFW to steam generator	*	X	X	X	X	X
32246, 32383	AFW to steam generator	*	X	X	X	X	X
32239, 32382	AFW to steam generator	*	X	X	X	X	X
32247, 32384	AFW to steam generator	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
MOTOR VALVE (MV-)							
32266, 32267	CC to RCP	*	X	X	X	X	X
32268, 32269	CC to RCP	*	X	X	X	X	X
32323, 32324	Feedwater pump discharge	TB	X	X	X	X	X
32325, 32326	Feedwater pump discharge	TB	X	X	X	X	X
32332, 32334	Cooling water return header	*	X	X	X	X	X
32023, 32024	Containment isolation - FW	B/X	X	X	X	X	X
32028, 32029	Containment isolation - FW	B/X	X	X	X	X	X
32040, 32043	Containment isolation - SB	*	X	X	X	X	X
32046, 32049	Containment isolation - SB	*	X	X	X	X	X
32044, 32058	Containment isolation - SB	C	X	X	X	X	X
32051, 32059	Containment isolation - SB	C	X	X	X	X	X
32073, 32176	Containment isolation - SI	*	X	X	X	X	X
32242, 32243	Containment isolation - AF	B/X	X	X	X	X	X
32248, 32249	Containment isolation - AF	B/X	X	X	X	X	X
DAMPER (CD- OR MD-)							
34177, 34176	Control room outside air	A/*	X	X	X	X	X
34142, 34145	Control room outside air	*	X	X	X	X	X
34143, 34144	Air handler discharge	*	X	X	X	X	X
34146, 34147	Control room exhaust	*	X	X	X	X	X
34179, 34181	Control Room PAC filter inlet	*	X	X	X	X	X
34178, 34180	Control Room PAC filter outside air	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
DAMPER (CD- OR MD-)							
34182, 34183	Control Room PAC filter outlet	*	X	X	X	X	X
34185, 34186	Waste gas storage area	FH	X	X	X	X	X
34187, 34188	Supply to elevation 695'	C	X	X	X	X	X
34189, 34190	Supply to elevation 695'	*	X	X	X	X	X
34191, 34192	480V Bus Room return	*	X	X			X
34193, 34194	480V Bus Room return	*	X	X			X
34195, 34196	Battery room supply	TB	X	X			X
34197, 34198	Battery room supply	TB	X	X			X
34199, 34200	4kv bus room supply	*	X	X			X
34201, 34202	480v bus room supply	*	X	X			X
34049	D1/D2 outside air supply	*	X	X	X	X	X
34136, 34139	DDCLP air supply	*	X	X	X	X	X
34137, 34138	DDCLP roof exhaust	*	X	X	X	X	X
32420, 32426	D5/D6 room outside air	*	X	X	X	X	X
32421, 32427	D5/D5 room exhaust	*	X	X	X	X	X
32422, 32428	D5/D6 room recirc	*	X	X	X	X	X
32423, 32429	D5/D6 outside air	*	X	X	X	X	X
32424, 32430	D5/D6 building exhaust	*	X	X	X	X	X
32425, 32431	D5/D6 building recirc	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
INSTRUMENTATION (Unit 1, 2 or Common Prefix)							
NM-51, 52	Nuclear Instrumentation	*	X	X	X	X	X
PT-429, 430	Pressurizer pressure	*	X	X	X	X	X
PT-431, 449	Pressurizer pressure	*	X	X	X	X	X
PT-709, 710	RCS wide range pressure	*	X	X	X	X	X
PT-468, 469, 482	Steam generator pressure	X/Y	X	X	X	X	X
PT-378, 479, 483	Steam generator pressure	C	X	X	X	X	X
PT-751, 761	RVLIS wide range pressure	B	X	X	X	X	X
LT-723, 724	Condensate tank level	TB	X	X	X	X	X
LT-426, 427, 428	Pressurizer level	*	X	X	X	X	X
LT-751, 752, 753	RVLIS level	B	X	X	X	X	X
LT-761, 762, 763	RVLIS level	B	X	X	X	X	X
LT-461, 462, 463	Steam generator level	*	X	X	X	X	X
LT-471, 472, 473	Steam generator level	*	X	X	X	X	X
LT-460, 470	Steam generator level	*	X	X	X	X	X
LT-487, 488	Steam generator level	*	X	X	X	X	X
LT-102, 171	BAST level	*	X	X	X	X	X
LT-189, 197	BAST level	*	X	X	X	X	X
LT-106, 172	BAST level	*	X	X	X	X	X
LT-920, 921	RWST level	*	X	X	X	X	X
FT-464, 465	Main steam line flow	*	X				
FT-474, 475	Main steam line flow	*	X				
13234, 13235	Core exit thermocouple	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

INSTRUMENTATION (Unit 1, 2 or Common Prefix)	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
13237, 13238	Core exit thermocouple	*	X	X	X	X	X
13239, 13240	Core exit thermocouple	*	X	X	X	X	X
13241, 13242	Core exit thermocouple	*	X	X	X	X	X
13243, 13245	Core exit thermocouple	*	X	X	X	X	X
13246, 13247	Core exit thermocouple	*	X	X	X	X	X
13248, 13249	Core exit thermocouple	*	X	X	X	X	X
13250, 13251	Core exit thermocouple	*	X	X	X	X	X
13252, 13253	Core exit thermocouple	*	X	X	X	X	X
13255, 13256	Core exit thermocouple	*	X	X	X	X	X
13258, 13259	Core exit thermocouple	*	X	X	X	X	X
13260, 13261	Core exit thermocouple	*	X	X	X	X	X
13262, 13263	Core exit thermocouple	*	X	X	X	X	X
13264, 13265	Core exit thermocouple	*	X	X	X	X	X
13266, 13267	Core exit thermocouple	*	X	X	X	X	X
13268, 13269	Core exit thermocouple	*	X	X	X	X	X
13270, 13271	Core exit thermocouple	*	X	X	X	X	X
13272, 12407	Core exit thermocouple	*	X	X	X	X	X
13408, 13410	Core exit thermocouple	*	X	X	X	X	X
13411, 13412	Core exit thermocouple	*	X	X	X	X	X
13413, 13414	Core exit thermocouple	*	X	X	X	X	X
13415, 13416	Core exit thermocouple	*	X	X	X	X	X
13418, 13419	Core exit thermocouple	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
INSTRUMENTATION (Unit 1, 2 or Common Prefix)							
13420, 13421	Core exit thermocouple	*	X	X	X	X	X
13422, 13423	Core exit thermocouple	*	X	X	X	X	X
13424, 13425	Core exit thermocouple	*	X	X	X	X	X
13426, 13428	Core exit thermocouple	*	X	X	X	X	X
13429, 13431	Core exit thermocouple	*	X	X	X	X	X
13432, 13433	Core exit thermocouple	*	X	X	X	X	X
13434, 13435	Core exit thermocouple	*	X	X	X	X	X
13436, 13437	Core exit thermocouple	*	X	X	X	X	X
13438, 13439	Core exit thermocouple	*	X	X	X	X	X
13440, 13441	Core exit thermocouple	*	X	X	X	X	X
13442, 13443	Core exit thermocouple	*	X	X	X	X	X
13444, 13445	Core exit thermocouple	*	X	X	X	X	X
TE-401, 403	RCS hot/cold leg temperature	*	X				
TE-403, 404	RCS hot/cold leg temperature	*	X				
TE-450, 451	RCS hot/cold leg temperature	*	X	X	X	X	X
15297, 15407	Waste gas storage area	FH	X	X	X	X	X
15298, 15408	Supply to elevation 695'	*	X	X	X	X	X
15299, 15409	Supply to elevation 695'	*	X	X	X	X	X
15300, 15415	Control room exhaust	A	X	X	X	X	X
15301, 15421	Control room outside air	*	X	X	X	X	X
15302, 15422	Control room outside air	*	X	X	X	X	X
15684, 15690	480V Bus room return	TB	X	X			X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
INSTRUMENTATION (Unit 1, 2 or Common Prefix)							
15685, 15691	480V Bus room return	TB	X	X			X
15686, 15692	Battery room supply	TB	X	X			X
15687, 15693	Battery room supply	*	X	X			X
15688, 15694	4 kv bus room supply	TB	X	X			X
15689, 15695	480v bus room supply	TB	X	X			X
CS46331, 46450	Reactor trip breaker	*	X	X	X	X	X
CS49629, 49562	Reactor trip breaker	*	X	X	X	X	X
CS46180, 49610	SI actuation	*	X	X	X	X	X
CS46408, 49545	SI actuation	*	X	X	X	X	X
CS46158, 46159	MSIV closure	*	X	X	X	X	X
CS49620, 49621	MSIV closure	*	X	X	X	X	X
FT-924, 925	Safety injection flow	*	X	X	X	X	X
23122, 23127	Auxiliary feedwater flow	*	X	X	X	X	X
23128, 23219	Auxiliary feedwater flow	*	X	X	X	X	X
PZ-HTRA/XD	Przr heater watts	*	X	X	X	X	X
PZ-HTRB/XD	Przr heater watts	*	X	X	X	X	X
XE-443, 444, 445	Przr safety valve flow	*	X	X	X	X	X
RE-01	Control room rad monitor	*	X	X	X	X	X
4190201, 4190202	Electrical bus status	*	X	X	X	X	X
4190203, 4190204	Electrical bus status	*	X	X	X	X	X
4190205, 4190206	Electrical bus status	*	X	X	X	X	X
4190301, 4190302	Electrical bus status	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
INSTRUMENTATION (Unit 1, 2 or Common Prefix)							
4190303, 4190304	Electrical bus status	*	X	X	X	X	X
4190305, 4190306	Electrical bus status	*	X	X	X	X	X
4190401, 4190402	Electrical bus status	*	X	X	X	X	X
4190403, 4190501	Electrical bus status	*	X	X	X	X	X
4190502, 4190503	Electrical bus status	*	X	X	X	X	X
4190504, 4190505	Electrical bus status	*	X	X	X	X	X
4190506, 4190701	Electrical bus status	*	X	X	X	X	X
4190702, 4190703	Electrical bus status	*	X	X	X	X	X
4190704, 4190705	Electrical bus status	*	X	X	X	X	X
4190706, 4192401	Electrical bus status	*	X	X	X	X	X
4192402, 4192403	Electrical bus status	*	X	X	X	X	X
4191801, 4191802	Electrical bus status	*	X	X	X	X	X
4191803, 4192301	Electrical bus status	*	X	X	X	X	X
4192302, 4192303	Electrical bus status	*	X	X	X	X	X
ELECTRICAL							
1-52/RTA, 1-52/RTB	Reactor trip breaker	*	X	X	X	X	X
1-52/BYA, 1-52/BYB	Reactor trip breaker	*	X	X	X	X	X
2-52/RTA, 2-52/RTB	Reactor trip breaker	*	X	X	X	X	X
2-52/BYA, 2-52/BYB	Reactor trip breaker	*	X	X	X	X	X
11 Batt, 12 Batt	Battery	*	X	X	X	X	X
21 Batt, 22 Batt	Battery	*	X	X	X	X	X

TABLE I.1.4-1 REQUIRED EQUIPMENT LIST

	DESCRIPTION	LOCATION FIG. I.3.1-1	MS	FW	VC	SB	AF
ELECTRICAL							
Bus 15, 16	4160 volt switchgear	*	X	X	X	X	X
Bus 25, 26, 27	4160 volt switchgear	*	X	X	X	X	X
Bus 111, 112	480 volt switchgear	*	X	X	X	X	X
Bus 211, 212	480 volt switchgear	*	X	X	X	X	X
Bus 121, 122	480 volt switchgear	*	X	X	X	X	X
Bus 221, 222	480 volt switchgear	*	X	X	X	X	X
MCC 1S, 2S	Pressurizer heater group A	*	X	X	X	X	X
MCC 1R, 2R	Pressurizer heater group B	*	X	X	X	X	X
DOORS							
Door 133, 182	Aux Bldg to Fuel Handling	X2	X	X	X	X	X
Door 134, 184	Aux Bldg to Fuel Handling	X1	X	X	X	X	X
Door 147, 273	Aux Bldg to Fuel Handling	A0	X	X	X	X	X
Door 155, 177	Aux Bldg to Fuel Handling	Y1	X	X	X	X	X

* Outside those areas that experience a harsh environment for any HELB event

TABLE I.3.1-1 AUXILIARY BUILDING - COMPARTMENT DATA

	A1	A0	A2
Gross Volume (ft^3)	146,035	37,410	149,205
Equipment	(20,655)	(4,045)	(15,560)
Net Volume (ft^3)	125,380	33,365	133,645
Surface Area (ft^2)	27,645	7,270	27,555

	B1	B0	B2
Gross Volume (ft^3)	101,130	38,725	114,850
Equipment	(23,005)	(6,805)	(26,700)
Net Volume (ft^3)	78,125	31,920	88,150
Surface Area (ft^2)	21,570	9,575	23,105

	X1		X2
Gross Volume (ft^3)	23,455		23,270
Equipment	(2,020)		(2,170)
Net Volume (ft^3)	21,435		21,100
Surface Area (ft^2)	5,410		5,920

	C1	C0	C2
Gross Volume (ft^3)	171,450	44,615	171,645
Equipment	(49,970)	(20,915)	(21,355)
Net Volume (ft^3)	121,480	23,700	150,290
Surface Area (ft^2)	34,900	8,685	36,070

TABLE I.3.1-1 AUXILIARY BUILDING - COMPARTMENT DATA

	D1	D0	D2
Gross Volume (ft^3)	11,930	86,165	11,930
Equipment	(1,405)	(32,765)	(1,280)
Net Volume (ft^3)	10,525	53,400	10,650
Surface Area (ft^2)	4,060	25,160	4,050

	Y1	Y2
Gross Volume (ft^3)	15,805	11,975
Equipment	(3,320)	(2,385)
Net Volume (ft^3)	12,485	9,590
Surface Area (ft^2)	5,090	4,685

Volume For Compartment	Includes Volume For Compartment
B1	F1 & G1
B2	F2 & G2
D0	H0, M0, N0, N1 & N2
C1	K1 & L1
C2	K2 & L2
Y3	O2

TABLE I.3.2-1 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS OUTSIDE CONTAINMENT

ID #	Description	Location
#11 Steam Generator - Main Steam		
MS1-B3	30″ nozzle @ turbine	Turb Bldg
MS1-B4	10″ branch to MSRs	Turb Bldg
MS1-B5	6″ branch to PORV	X1
MS1-B6	6″ branch to AFWP	X1
MS1-C1	First elbow after MSIV	Y1
MS1-C3	Second elbow after MSIV	X1
MS1-C3	Steam dump riser tee	B1
MS1-C4	Upper elbow at G-row	Turb Bldg
MS1-C5	Equalizing line tee	Turb Bldg
#12 Steam Generator - Main Steam		
MS1-B9	30″ nozzle @ turbine	Turb Bldg
MS1-B10	16″ branch to MSRs	Turb Bldg
MS1-B11	6″ branch to PORV	A1
MS1-B12	6″ branch to AFWP	B1
MS1-C6	Safety valve riser tee	B1
MS1-C7	Steam dump riser tee	B1
MS1-C8	Equalizing line tee	Turb Bldg
MS1-C9	After equalizing line tee	Turb Bldg
MS1-C10	Steam dump header	A1

TABLE I.3.2-1 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS OUTSIDE CONTAINMENT

ID #	Description	Location
#21 Steam Generator - Main Steam		
MS2-B3	30″ nozzle @ turbine	Turb Bldg
MS2-B4	10″ branch supply to MSRs	Turb Bldg
MS2-B5	6″ branch to PORV	X2
MS2-B6	6″ branch to AFWP	X2
MS2-C1	First elbow downstream of MSIV	Y2
MS2-C2	Second elbow downstream of MSIV	X2
MS2-C3	Steam dump riser tee	B2
MS2-C4	Upper elbow at G-row	Turb Bldg
MS2-C5	Equalizing line tee	Turb Bldg
#22 Steam Generator - Main Steam		
MS2-B9	30″ nozzle @ turbine	Turb Bldg
MS2-B10	16″ branch supply to MSRs	Turb Bldg
MS2-B11	6″ branch to PORV	A2
MS2-B12	6″ branch to AFWP	B2
MS2-C6	Steam dump riser tee	B2
MS2-C7	Equalizing line tee	Turb Bldg
MS2-C8	After equalizing line tee	Turb Bldg
#11 Steam Generator - Feedwater		
FW1-B1	16″ nozzle @ 15B heater	Turb Bldg

TABLE I.3.2-1 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS OUTSIDE CONTAINMENT

ID #	Description	Location	
#12 Steam Generator - Feedwater			
FW1-B4	16″ outlet nozzle - 15A heater	Turb Bldg	00-300
FW1-C3	16″ 15 A&B heater tee	Turb Bldg	
#21 Steam Generator - Feedwater			
FW2-B1	16″ nozzle @ 25B heater	Turb Bldg	
FW2-C1	4″ control valve bypass line	X2	00-300
FW2-C2	4″ control valve bypass line	X2	
#22 Steam Generator - Feedwater			
FW2-B4	16″ nozzle @ 25A heater	Turb Bldg	
FW2-C4	4″ control valve bypass line	B2	00-300
FW2-C5	4″ control valve bypass line	B2	
FW2-C6	4″ control valve bypass line	B2	
FW2-C7	4″ control valve bypass line	B2	
FW2-C8	4″ control valve bypass line	B2	
#11 Chemical and Volume Control System - Letdown			
VC1-B1	2″ containment penetration	D1	
VC1-B2	2″ intermediate anchor	D1	
VC1-B3	2″ letdown heat exchanger nozzle	L1	

TABLE I.3.2-1 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS OUTSIDE CONTAINMENT

ID #	Description	Location
#21 Chemical and Volume Control System - Letdown		
VC2-B1	2" containment penetration	D2
VC2-B2	2" intermediate anchor	H0
VC2-B3	2" letdown heat exchanger nozzle	L2
VC2-C1	2" tee from RCDT pump	D2
#11 Steam Generator - Blowdown		
SB1-B1	2" containment penetration	C1
SB1-B2	2" intermediate anchor	C1
SB1-B3	2" intermediate anchor	D1
SB1-B4	2" flash tank nozzle	D1
SB1-B5	2" flash tank nozzle	D1
#12 Steam Generator - Blowdown		
SB1-B6	2" containment penetration	C1
SB1-B7	2" intermediate anchor	C1
SB1-B8	2" intermediate anchor	D1
SB1-B9	2" flash tank nozzle	D1
SB1-B10	2" flash tank nozzle	D1
SB1-C1	after CV-31417	D1

TABLE I.3.2-1 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS OUTSIDE CONTAINMENT

ID #	Description	Location
#21 Steam Generator - Blowdown		
SB2-B1	2" containment penetration	C2
SB2-B2	2" intermediate anchor	C2
SB2-B3	2" flash tank nozzle	D2
SB2-B4	2" flash tank nozzle	D2
SB2-C1	Elbow before MV-32051	D2
#22 Steam Generator - Blowdown		
SB2-B5	2" containment penetration	C2
SB2-B6	2" flash tank nozzle	D2
SB2-B7	2" flash tank nozzle	D2
#11 Steam Generator - Steam Supply to Auxiliary Feedwater Pump		
MS1-B6	6" main steam supply branch	X1
AF1-B1	3" intermediate anchor	X1
AF1-B2	3" common terminal end	Turb Bldg
AF1-C1	Elbow before MV-32016	X1
AF1-C2	Elbow after MV-32016	X1
AF1-C3	Tee at common connection	B1
#12 Steam Generator - Steam Supply to Auxiliary Feedwater Pump		
MS1-B12	6" main steam supply branch	B1
AF1-C4	Elbow before MV-32017	B1
AF1-C5	Elbow after MV-32017	B1
AF1-C6	Elbow before common connection	B1

TABLE I.3.2-1 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS OUTSIDE CONTAINMENT

ID #	Description	Location
#21 Steam Connection - Steam Supply to Auxiliary Feedwater Pump		
MS2-B6	6" main steam supply branch	X2
AF2-B1	3" common terminal end	Turb Bldg
AF2-C1	Elbow in common line	B2
AF2-C2	Elbow in common line	B2
AF2-C3	Elbow in common line	B2
AF2-C4	Elbow in common line	E2 (encap)
AF2-C5	Elbow in common line	Turb Bldg
#22 Steam Generator - Steam Supply to Auxiliary Feedwater Pump		
MS2-B12	6" main steam supply branch	B2
AF2-C6	First elbow after MV-32020	B2
AF2-C6	Second elbow after MV-32020	B2

TABLE I.3.2-2 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS INSIDE CONTAINMENT

ID#	Description
#11 Steam Generator	
MS1-B1	32" outlet nozzle
MS1-B2	31" anchor elbow
FW1-B2	16" anchor elbow
FW1-B3	16" inlet nozzle
FW1-C1	16" upper elbow
FW1-C2	16" at AFW connection
#12 Steam Generator	
MS1-B7	32" outlet nozzle
MS1-B8	31" anchor elbow
FW1-B5	16" anchor elbow
FW1-B6	16" inlet nozzle
FW1-C4	16" lower elbow
FW1-C5	16" upper elbow
FW1-C6	16" at AFW connection
#21 Steam Generator	
MS2-B1	32" outlet nozzle
MS2-B2	31" anchor elbow
FW2-B2	16" anchor elbow
FW2-B3	16" inlet nozzle
FW2-C3	16" at AFW connection
#22 Steam Generator	
MS2-B7	32" outlet nozzle
MS2-B8	31" anchor elbow
FW2-B5	16" anchor elbow
FW2-B6	16" at AFW connection
FW2-B7	16" inlet nozzle
FW2-C9	16" lower elbow
FW2-C10	16" upper elbow

00-300
00-300
00-300
00-300

TABLE I.3.2-3 HIGH ENERGY LINE BREAK (B) AND CRACK (C) LOCATIONS AUXILIARY BUILDING COMPARTMENTS

A1		A0	A2	
MS1-B11	MS1-C10	None	MS2-B11	

B1		B0	B2	
MS1-B12	MS1-C3	None	MS2-B12	MS2-C3
MS1-C6	MS1-C7		MS2-C6	FW2-C4
AF1-C3	AF1-C4		FW2-C5	FW2-C6
AF1-C5	AF1-C6		FW2-C7	FW2-C8
			AF2-C1	AF2-C2
			AF2-C3	AF2-C6
			AF2-C7	

00-300

C1		L1	L2	C2	
SB1-B1	SB1-B2	VC1-B3	VC2-B3	SB2-B1	SB2-B2
SB1-B6	SB1-B7			SB2-B5	

D1		H0	D2	
VC1-B1	VC1-B2	VC2-B2	VC2-B1	VC2-C1
SB1-B3	SB1-B4		SB2-B3	SB2-B4
SB1-B5	SB1-B8		SB2-B6	SB2-B7
SB1-B9	SB1-B10		SB2-C1	
SB1-C1				

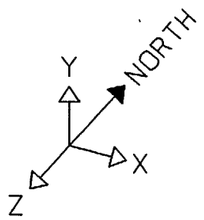
X1		X2	
MS1-B5	MS1-B6	MS2-B5	MS2-B6
MS1-C2	AF1-B1	MS2-C2	FW2-C1
AF1-C1	AF1-C2	FW2-C2	

00-300

Y1	Y2
MS1-C1	MS2-C1

NH-172998-2

REVISIONS			
B	AS BUILT PER SAFETY EVALUATION 478-AI-93 & DRR P1-98-056	DWN. CHK'D. MOD. FILMED	

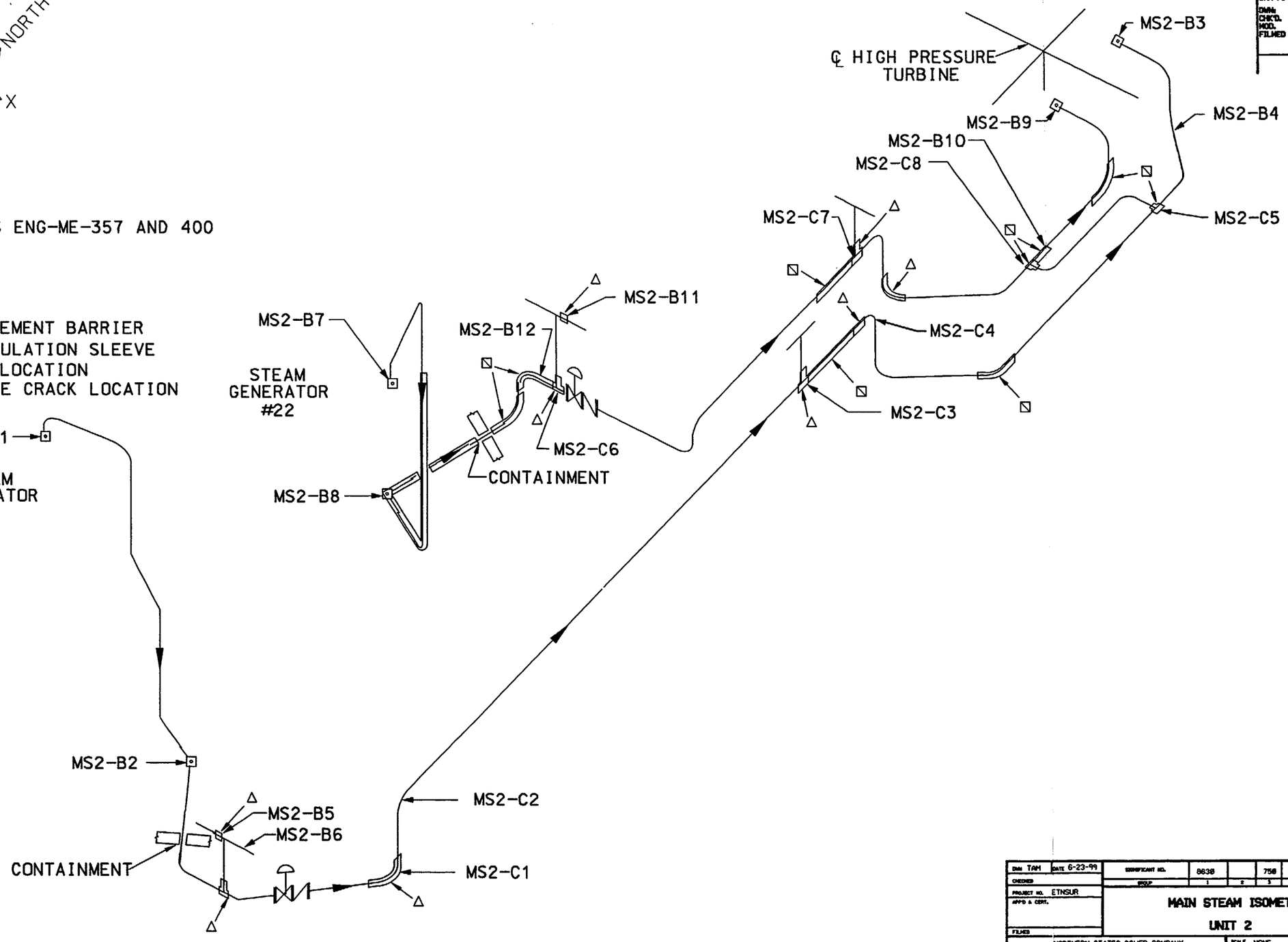


CALCULATIONS ENG-ME-357 AND 400

LEGEND:

- ⊡ – ANCHOR
- ⧅ – IMPINGEMENT BARRIER
- △ – ENCAPSULATION SLEEVE

MS2-BX– BREAK LOCATION
MS2-CX– LEAKAGE CRACK LOCATION



DWN TAM	DATE 6-23-99	SIGNIFICANT NO.	8638		750	1A2	6900 A100 4200	3	1100
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO. ETNSUR									
APPD & CERT.									
FILMED									

MAIN STEAM ISOMETRIC

UNIT 2

NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MN

SCALE NONE | REV. B

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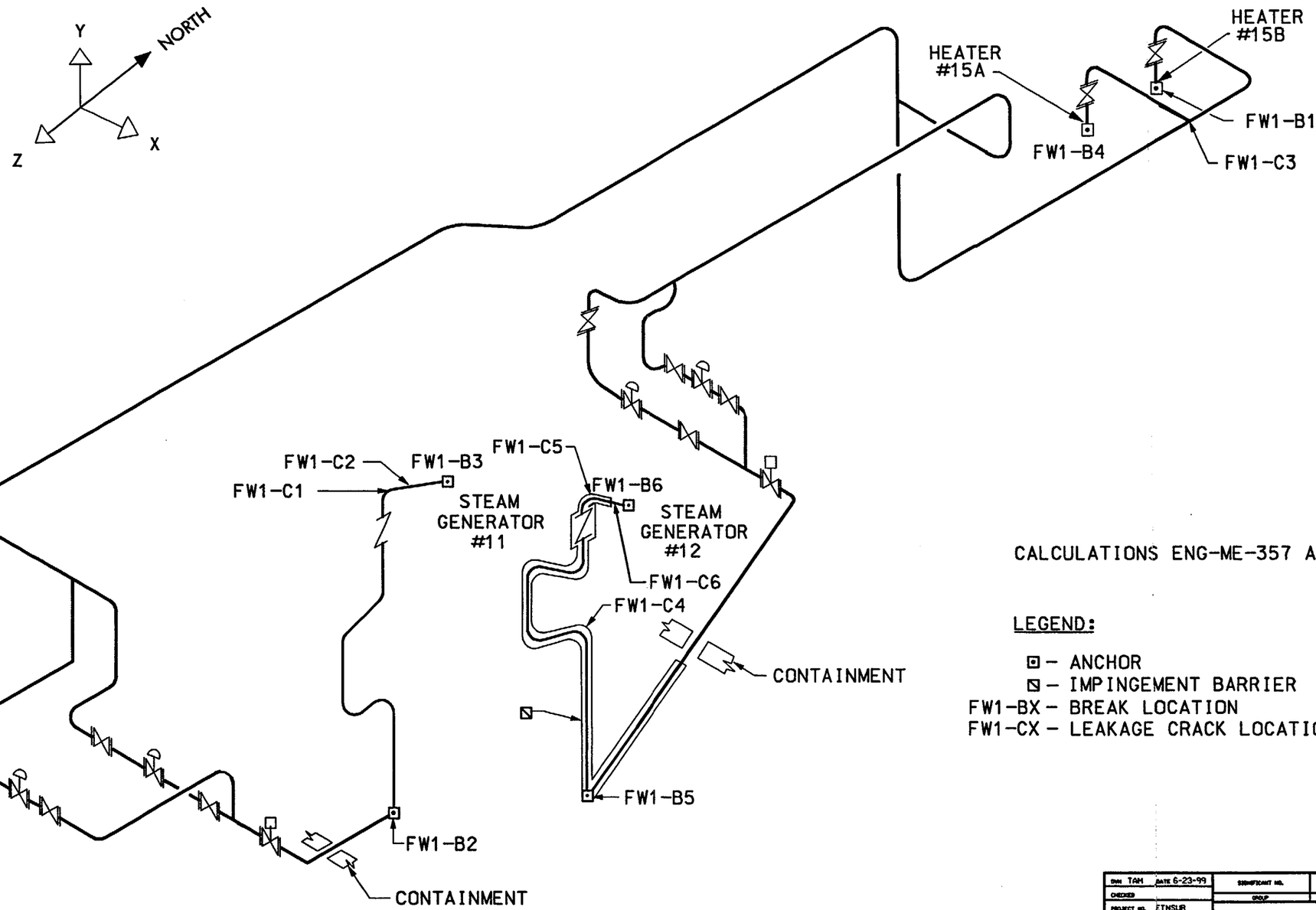
FIGURE I.3.2-2 REV. 23

NH-172998-3

REVISIONS
B AS BUILT PER SAFETY EVALUATION 478-AI-83 & DRR PI-88-856 DWN CHK'D MOD. FILMED
C1-N AS BUILT PER SAFETY EVALUATION 478-AI-83, REV 1 APP 2a AND DRR PI-88-356



CALCULATIONS ENG-ME-357 AND 400

LEGEND:

- ⊡ – ANCHOR
- ⧅ – IMPINGEMENT BARRIER
- FW1-BX – BREAK LOCATION
- FW1-CX – LEAKAGE CRACK LOCATION

DWN TAH	DATE 6-23-99	SIGNIFICANT NO.	8638		750	18.2	6900 A100 4200	3	1100
CHECKED		GROUP	1	2	3	4	5	CL	6
PROJECT NO. ETNSUR									
APP'D & CERT.		FEEDWATER ISOMETRIC							
FILMED		UNIT 1							
NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MN		SCALE NONE		REV. B					
		NH-172998-3							

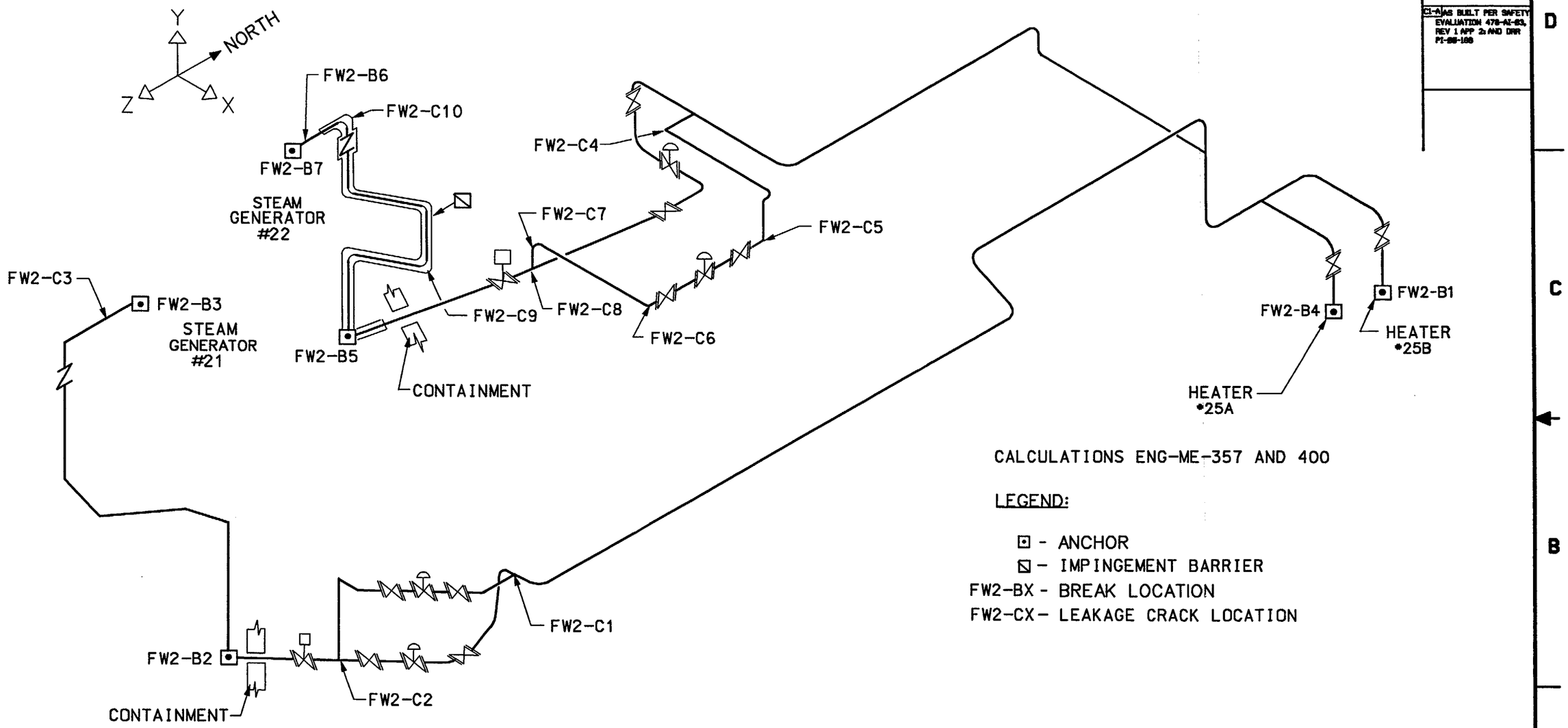
FIGURE I .3.2-3 REV. 23

NH-172998-4

REVISIONS

B | AS BUILT PER SAFETY EVALUATION 478-AI-93 & DRR PI-98-056
DWN: CHK'D. MOD. FILMED

C1-A | AS BUILT PER SAFETY EVALUATION 478-AI-93, REV 1 APP 2 AND DRR PI-98-188



CALCULATIONS ENG-ME-357 AND 400

LEGEND:

⊡ - ANCHOR
⦻ - IMPINGEMENT BARRIER
FW2-BX - BREAK LOCATION
FW2-CX - LEAKAGE CRACK LOCATION

Drawn TAM	Date 6-23-99	SIGNIFICANT NO.	8630		750	1&2	6900 A188 4206	3 1188
CHECKED		GROUP	1	2	3	4	5	CL 6
PROJECT NO. ETNSUR								
APPD & CERT.		FEEDWATER ISOMETRIC						
FILMED		UNIT 2						
NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MN							SCALE NONE	REV. B
							NH-172998-4	

FIGURE I.3.2-4 REV. 23