BWR OWNERS' GROUP

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May 31, 1991
BWROG 91-072

Director of Nuclear Reactor Regulation
US Nuclear Regulatory Commission
Mail Station P1-137
Washington, DC 20555

ATTENTION: Ashok C. Thadani, Director
Division of Systems Technology

SUBJECT: **LONG-TERM STABILITY SOLUTIONS LICENSING METHODOLOGY**

Dear Mr. Thadani:

Enclosed for NRC review and approval is Report NEDO 31960 entitled "Long-Term Stability Solutions Licensing Methodology." This report was prepared for the BWR Owners' Group by GE and describes the methodologies developed for evaluating appropriate set points and performance criteria for the long-term solutions to the stability issue. Also included are descriptions of the long-term solutions concepts currently under consideration by the BWR Owners' Group. The stability methodologies are being submitted for NRC review and approval. The long-term solution descriptions are provided to demonstrate the application of the methodology and to obtain NRC acceptance of the design concepts. Specific hardware design will be treated in separate submittals and NRC approval requested at that time.

Methodologies for both the prevention of stability-related power/flow oscillations, and the detection and suppression of these oscillations are described in this report. The prevention methodology conservatively defines the power/flow region in which oscillations can occur. This methodology will be used to establish the design features and setpoints for solutions which automatically prevent operation in a potentially unstable region. The detection and suppression methodology is used to establish the design features and setpoints of systems which will automatically detect and suppress oscillations which could potentially result in conditions exceeding the MCPR safety limit. Taken collectively, these methodologies provide a comprehensive basis for judging the adequacy of a variety of solution concepts; including in some cases, the demonstration of adequacy of existing reactor protection systems for protection against instabilities.

Because of the variety of plant types, and the need to accommodate differing operating philosophies and owner-specific constraints, several solution alternatives are being pursued by the BWR Owners' Group. These alternatives have been discussed with your staff in recent BWROG/NRC meetings and are described more completely in this report.

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The conclusions contained in this letter and attached report have been endorsed by a substantial number of the members of the BWR Owners' Group; however, it should not be interpreted as a commitment of any individual member to a specific course of action. Each member must formally endorse the BWR Owners' Group position in order for that position to become the member's position.

Sincerely,

George J Beck

George J. Beck, Chairman
BWR Owners' Group

GJB:jz

Enclosure

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BWR OWNERS' GROUP
LONG-TERM STABILITY SOLUTIONS
LICENSING METHODOLOGY

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GE Nuclear Energy

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May 1991

Licensing Topical Report

BWR Owners' Group Long-Term Stability Solutions Licensing Methodology

NEDO-31960 BWROG Long-Term Stability Solutions Licensing Methodology

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ABSTRACT

Compliance with stability licensing criteria set forth in 10CFR50 Appendix A, General Design Criterion (GDC-12), is achieved by either preventing stability-related neutron flux oscillations or detecting and suppressing the oscillations prior to exceeding specified acceptable fuel design limits. The BWR Owners' Group (BWROG) has developed long-term solutions which incorporate either prevention or detection and suppression features, or use a combination of both features to ensure compliance with GDC-12. Methodologies have been developed to support the licensing of these long-term solutions.

For prevention features, a methodology has been developed which determines the region of the operating domain which may be susceptible to instabilities. The method uses conservative inputs, along with criteria which account for uncertainties in the model to ensure a low probability of an oscillation occurring outside the defined region. This methodology can be used to define an exclusion region in which operation will be precluded by either administrative controls or by automatic actions.

Detection and suppression solutions use the Local Power Range Monitors (LPRMs) as the basic detection devices, and differ primarily in the way in which LPRM signals are combined and evaluated to detect the presence of an oscillation. A methodology has been developed that relates the fuel thermal response in the limiting fuel assembly to the LPRM signals. This methodology can be used to confirm that a specific detection and suppression solution provides protection of the Minimum Critical Power Ratio (MCPR) Safety Limit. Examples of solution options that are being evaluated by the BWR Owners' Group are provided to demonstrate the application of the described methodologies. These examples provide sufficient detail to allow generic approval of the methodologies so that final hardware and software designs can be performed with an established analytical basis.

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1.0 INTRODUCTION

1.1 BACKGROUND

The stability licensing basis for all U.S. nuclear power plants is set forth in GDC-12. This requires assurance that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are either not possible or can be reliably and readily detected and suppressed. Historically, compliance with GDC-12 was achieved by demonstrating that thermal-hydraulic stability induced neutron flux oscillations were not expected. More recently, operating experience indicates that the thermal-hydraulic stability characteristics of a BWR are strongly influenced by a number of design and operating parameters which will vary depending upon the specific plant conditions at the time of the event. This was recognized and recommendations for special operator actions were provided in GE Service Information Letter (SIL) 380 Revision 0 (August 11, 1982) and Revision 1 (February 10, 1984). These recommendations were accepted by the NRC as providing adequate compliance with the detection and suppression provision of GDC-12.

Following the March 9, 1988 LaSalle-2 event, evaluations indicated that under certain conditions, margins to safety limits may be less than previously expected. These findings were promptly reported to the NRC and interim corrective actions (ICAs) recommended by GE and the BWR Owners' Group were implemented at all U.S. plants. NRC Bulletin 88-07 Supplement 1, "Power Oscillations in Boiling Water Reactors (BWRs)" (Reference 1) endorsed the ICAs and the BWR Owners' Group program to develop generic long-term solutions to the stability issue.

The BWROG program has successfully developed the necessary design and evaluation methodology to analyze thermal-hydraulic stability and has identified several viable approaches to the long-term resolution of the stability issue. Details of this methodology are provided in the body of this report and examples of the current solution concepts are discussed in Section 4.0 and Appendix A.

1.2 HISTORY OF BWROG PROGRAM

Following the 1988 LaSalle-2 event, the BWR Owners' Group and GE undertook a program to evaluate the implications of thermal-hydraulic stability for plant operation. Specifically, an engineering scoping analysis (Reference 2) was performed to evaluate the margin to the MCPR Safety Limits during regional oscillations and determine the plant instrumentation response during the oscillations. That study indicated the potential for a safety limit violation for certain large amplitude regional oscillations. As a result, ICAs were identified to supplement the general guidelines given in GE SIL 380, Revision 1. These ICAs provided the basis for the actions promulgated by the NRC in Bulletin 88-07, Supplement 1, and were promptly implemented by all domestic BWR utilities.

Subsequently, the BWR Owners' Group initiated a program to develop generic long-term solutions to the stability issue. Throughout this program, the NRC has been kept fully informed regarding its progress and direction. Feedback from the NRC has been considered in the selection of specific options for development and in the preparation of a licensing approach. The generic approach to resolving the stability issue was documented in the BWROG Report "Licensing Basis for Long-Term Solutions to BWR Stability" (Reference 3) and a supplement to that report (Reference 4) containing information on two additional solution options.

To provide a statistically-based assessment of the protection provided by various detection and suppression options, the BWROG program supported development of methodology to evaluate oscillation characteristics and plant instrumentation response. This methodology was developed by GE and technically reviewed by the Stability Committee of the BWR Owners' Group and was discussed with the NRC on several occasions. Both GE and the BWR Owners' Group have concluded that this methodology provides a technically sound basis for the design and evaluation of the various long-term solution options.

The BWROG development activities have also produced the long-term solution options described in Appendix A to this report. These options have been discussed with the NRC on numerous occasions. It is the BWR Owners' Group position that these solutions provide an appropriate level of protection for stability-related neutron flux oscillations and fully comply with the requirements of GDC-12.

1.3 APPROACH TO RESOLUTION OF THE STABILITY ISSUE

Based on guidance from the NRC, the following criteria for resolution of the stability issue were established:

(1) Solutions must satisfy GDC-12.

(2) Solutions should not depend upon development of a new transient boiling dryout correlation.

(3) Some form of automatic suppression function is appropriate (the specific function may vary for different plant type applications).

(4) Solutions should minimize the need for cycle specific analysis which requires NRC review.

(5) Solutions must be applicable to all current fuel designs and operating strategies.

Although observed thermal-hydraulic oscillations in BWRs have not resulted in fuel failures in nearly 800 reactor-years of operation, BWROG studies have shown that regional oscillations could potentially result in conditions that could violate the specified MCPR Safety Limit. While it is recognized that the MCPR Safety Limit is overly conservative for application to thermal-hydraulic oscillations, this limit will be used at this time as the basis for resolution of the stability issue. In fact, additional margin will be added to the safety limit as the design goal for those options which rely on detection and suppression of oscillations. This approach provides a high degree of assurance that the safety limit will not be violated for any expected oscillation event.

Using a conservative design goal is a prudent approach, since the large number of parameters potentially affecting the stability performance of a given plant makes analysis of all possible combinations impractical. The combination of a design goal providing substantial margin to the safety limit and an analysis based on the range of expected operating conditions provides a high degree of assurance that the safety limit will not be violated as a result of events that potentially could occur during the life of a plant.

In addition to detection and suppression based solutions, other solutions have also been studied and are included in this report. One alternative solution provides a trip upon entering a conservatively defined "exclusion region" which encompasses the power and flow conditions in which oscillations could occur. Another alternative, applicable only to a certain class of plants, demonstrates that the mode of potential oscillations can be well characterized by analysis. For this class of plants, existing protective features are shown to provide adequate protection.

The objective of all solutions is to provide automatic protection for oscillations that have the potential to occur in a plant lifetime.

1.4 PURPOSE OF THIS REPORT

This report describes the analytical methodologies developed for the BWROG to resolve the thermal-hydraulic stability issue. Solution concepts using this methodology are also being submitted for NRC review and acceptance (Appendix A). Since introduction of any new protection system has the potential for a significant impact on plant operation, it is the purpose of this licensing topical report to establish the basis for an understanding between the NRC and the BWR Owners' Group on acceptable analytical methodology and solution concepts. NRC acceptance of the methodologies described in Sections 5.0 and 6.0 is required to further optimize solution concepts as the BWR Owners' Group proceeds with the hardware/software design phase. NRC acceptance of the specific concepts described in Section 4.0 and Appendix A is required to allow utilities to select a preferred solution.

2.0 SUMMARY AND CONCLUSIONS

Licensing methodology and long-term solution concepts developed by GE in support of the BWROG Stability Program are described. The methodologies and solution concepts consider both the prevention and the detection and suppression approaches and provide the basis for protection system designs which are applicable to all BWRs in the US. It should be noted that several of the concepts take advantage of unique features of a particular class of plant and are not generically applicable. Other concepts apply to all plants and provide flexibility in the selection of a solution approach for all plants.

The stability methodologies described in Sections 5.0 and 6.0 and the long-term solution concepts described in Appendix A are being submitted for NRC review and approval. Other applications of these methodologies are possible and alternate concepts may be proposed in the future.

Solution descriptions and general requirements are summarized in Section 4.0 and are described in more detail in Appendix A. The methodology used to define the range of power/flow conditions under which stability related oscillations are expected is discussed in Section 5.0. This methodology provides the basis for defining the region in the power/flow map in which operation will not be allowed under prevention options. Section 6.0 discusses the methodology used to support the detection and suppression options which take advantage of the ability to detect oscillations and to initiate appropriate actions to suppress them.

3.0 DEFINITIONS

3.1 POWER/FLOW MAP

The power/flow map (Figure 3-1) depicts the possible power and flow combinations for a GE BWR.

Rod lines (e.g., line A on Figure 3-1) are lines of constant control rod configuration and xenon concentration that are traversed by changes in recirculation (core) flow. Increases in recirculation flow cause both reactor core flow and power to increase. Conversely, decreasing flow causes movement down line A, thereby decreasing power.

Line B on Figure 3-1 represents power changes without flow changes accomplished by (1) control rod manipulation, (2) feedwater temperature changes, and (3) xenon concentration changes. Withdrawal of control rods, a reduction in feedwater temperature, or a decrease in xenon concentration (core-wide relative to previous conditions) produces an increase in power. Insertion of control rods, an increase in feedwater temperature, or an increase in xenon concentration causes power to move down line B.

3.2 AUTOMATIC SUPPRESSION FUNCTION (ASF)

The ASF associated with any of the stability solutions initiates control rod insertion without operator actions, such that the region of potential instability (Figure 3-2) is exited quickly or oscillations are suppressed prior to violation of the MCPR Safety Limit.

In addition to full reactor scram, some BWR designs have the capability to automatically insert a limited number of control rods using Select Rod Insert (SRI). Control rods selected for the SRI function are scrammed upon receipt of the initiation signal with an associated rapid power reduction. The power reduction that can be achieved with SRI depends on the number and location of the control rods selected, the control rod pattern and the cycle exposure.

3.3 PEAK-TO-MINIMUM/AVERAGE ((P-M)/A)

During oscillations, a minimum (M) and peak (P) power will be observed. The difference is the peak-to-minimum value (P-M). To provide a relative measure of the oscillation, the peak-to-minimum value can be divided by the average (A). This provides a measure of the oscillation magnitude normalized to its average value during the oscillations. (P-M)/A is a term that is applied to many parameters such as bundle powers, LPRM signals, etc.

3.4 PLANT GROUP

A Plant Group is comprised of those plants which are similar with respect to parameters important to thermal-hydraulic stability. Evaluations performed for a representative plant are applicable to all plants within the group.

3.5 DECAY RATIO/GROWTH RATE

Decay ratio is a measure of the stability of an oscillating system and is defined as the value of one peak in the oscillation to the amplitude of the peak immediately preceding it (e.g., x_n/x_{n-1}). The amplitude is measured relative to the average amplitude of the signal ($x = P-A$). A stable system is characterized by a decay ratio of less than 1.0; an unstable system has a decay ratio greater than 1.0 (Figure 3-3). Decay ratios greater than 1.0 are referred to as growth rates.

3.6 OSCILLATION CONTOUR

An oscillation contour is the spatial distribution of oscillation magnitudes in the core. It will generally be expressed as a normalized value, (P-M)/A. For core-wide oscillations, the oscillation contour is uniform across the core, since, at each point in the core, in the x-y plane, the oscillation magnitude normalized to the initial steady-state value at that point is the same. For regional oscillations, the (P-M)/A value varies in the x-y plane.

3.7 ACRONYMS AND ABBREVIATIONS

ANF	-	Advanced Nuclear Fuels
APRM	-	Average Power Range Monitor
ARI	-	Alternate Rod Insertion
ASF	-	Automatic Suppression Function
ATWS	-	Anticipated Transient Without Scram
BOCn	-	Beginning-of-Cycle n
BOEC	-	Beginning-of-Equilibrium-Cycle
BWR	-	Boiling Water Reactor
BWROG	-	Boiling Water Reactor Owners' Group
CMFLPD	-	Core Maximum Fraction of Limiting Power Density
CPR	-	Critical Power Ratio
DR	-	Decay Ratio
EOCn	-	End-of-Cycle n
EOEC	-	End-of-Equilibrium-Cycle
EW	-	East-to-West
FCV	-	Flow Control Valve
FFWTR	-	Final Feedwater Temperature Reduction
FMCPR	-	Final Minimum Critical Power Ratio
FRTP	-	Fraction of Rated Thermal Power
FWHOS	-	Feedwater Heater Out-of-Service
GDC	-	General Design Criteria
GE	-	General Electric Company
ICA	-	Interim Corrective Actions
ICPR	-	Initial Critical Power Ratio
LBS	-	LPRM-Based System
LCO	-	Limiting Condition for Operation
LOFH	-	Loss of Feedwater Heating
LPRM	-	Local Power Range Monitor
MCPR	-	Minimum Critical Power Ratio
MOCn	-	Middle-of-Cycle n
MOEC	-	Middle-of-Equilibrum-Cycle
MSIV	-	Main Steam Line Isolation Valve
NESW	-	Northeast-to-Southwest
NMS	-	Neutron Monitoring System

NS	-	North-to-South
NUMAC	-	Nuclear Measurement and Control
NWSE	-	Northwest-to-Southeast
OPRM	-	Oscillation Power Range Monitor
PRM	-	Power Range Monitor
RBM	-	Rod Block Monitor
RPS	-	Reactor Protection System
RPT	-	Recirculation Pump Trip
SER	-	Safety Evaluation Report
SRI	-	Select Rod Insert
STPM	-	Simulated Thermal Power Monitor (STP, TPM)
WRNM	-	Wide Range Neutron Monitor
3D	-	Three-Dimensional

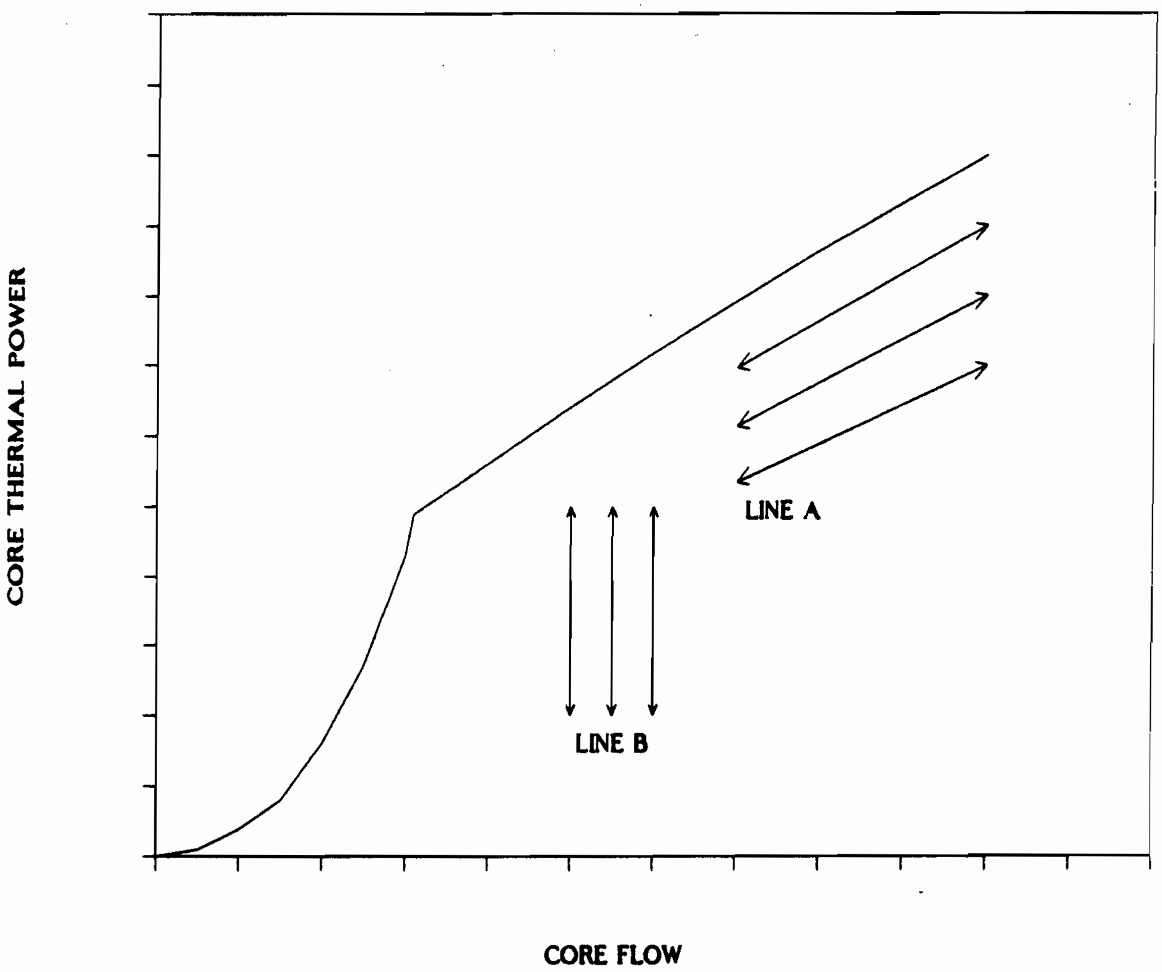

FIGURE 3-1. POWER/FLOW MAP

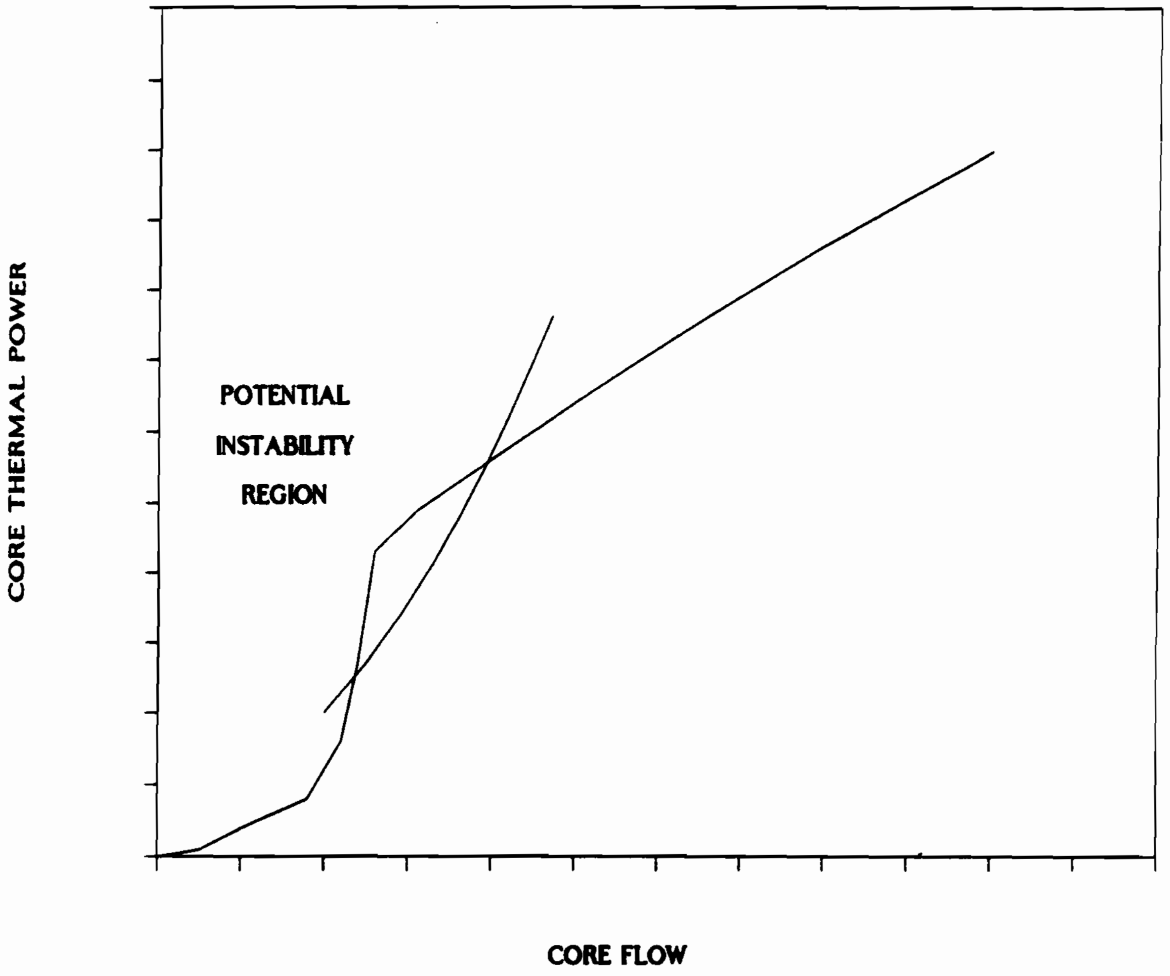

FIGURE 3-2. POTENTIAL INSTABILITY REGION

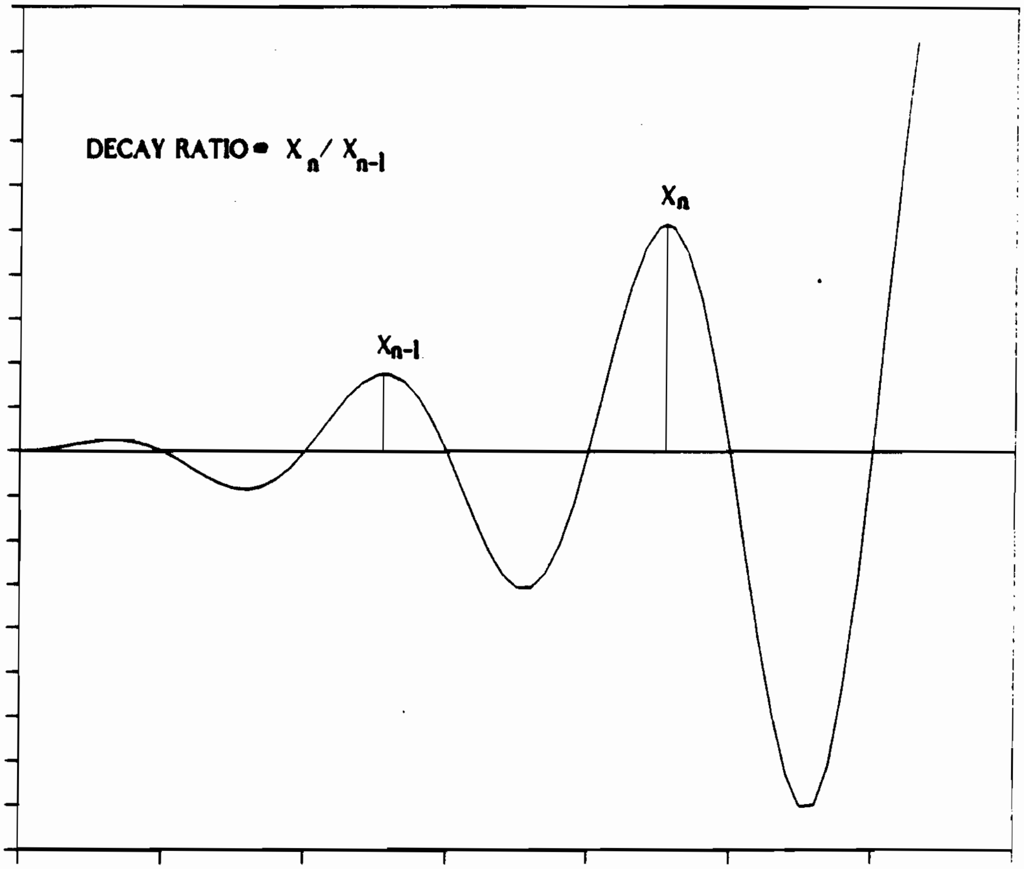

FIGURE 3-3. DECAY RATIO/GROWTH RATE

4.0 SOLUTION DESCRIPTIONS AND GENERAL REQUIREMENTS

4.1 SOLUTION CONCEPTS

GDC-12 states that the reactor and associated protection systems must be designed such that power oscillations are not possible, or can be readily detected and suppressed without exceeding specified fuel design limits. Compliance with GDC-12 can be demonstrated by calculating decay ratios for allowable operating conditions and restricting operation, if necessary, so that potentially unstable power/flow conditions are not encountered. This is called the prevention approach.

Alternatively, the detection and suppression approach may be used to satisfy GDC-12 by using existing, new, or modified plant instrumentation to detect and suppress oscillations prior to exceeding fuel design limits. The typical detection and suppression system monitors local or average neutron flux, and initiates an Automatic Suppression Function (i.e., scram or Select Rod Insert) when oscillating signals reach a predetermined level.

The prevention and detection and suppression concepts, either individually or in combination, can be applied to create a long-term solution to the stability issue. Since December 1988, the BWROG Stability Committee's primary objective has been to develop long-term solutions that meet regulatory requirements while minimizing unacceptable operating and modification impacts. Based on several BWROG and GE discussions with the NRC, automatic protection has been incorporated as an essential element of the long-term solutions proposed in this report.

Because of the variety of plant types, and the need to accommodate differing operating philosophies and owner-specific concerns, several solution alternatives are being pursued. For several specific BWR units, existing systems and plant features already provide sufficient detection and suppression of reactor instabilities. For these units, the methodology described in Sections 5.0 and 6.0 (or similar methodology described separately by the BWR/2 owners) is applied to demonstrate the sufficiency of existing systems. For most BWR units, new or modified plant systems will be required. A summary description of all BWROG long-term solutions is provided in Section 4.3.

4.2 SUPPORTING METHODOLOGY

Implementation of either or both of the prevention and detection and suppression concepts requires specific analyses to determine or confirm the acceptability of the allowable operating region and to confirm the acceptability of detection and suppression systems and trip setpoints. These analyses create a new safety analysis basis.

Application of the prevention concept requires use of computer models, such as frequency domain computer codes, which can calculate accurate decay ratios. Both the fundamental mode of oscillation and any higher order modes which are expected must be considered in the methodology. Decay ratio analyses must account for uncertainties in the computer model employed, and variations and uncertainties in key input parameters such as power distribution and moderator density reactivity coefficient. Various fuel dimensions and thermal-mechanical designs must also be considered. The GE/BWROG approach uses the FABLE code (Reference 5) and an overall conservative methodology to calculate core and channel decay ratios as a function of core power and core flow. Confirmatory analyses are used to demonstrate the conservatism of this approach (Section 5.0).

Detection and suppression schemes use the Local Power Range Monitors (LPRMs) to generate a signal that is monitored for oscillations. The LPRMs can be monitored individually, or combined in a number of different ways. A detection and suppression methodology must consider how the LPRMs respond in time and space to expected modes of oscillations. It must also consider the impact of LPRMs out of service, the failure of a single protection subsystem channel, and the time it takes to detect an oscillation and automatically achieve suppression.

The MCPR response of limiting fuel bundles is compared to the MCPR Safety Limit to determine the acceptability of the fuel response to an oscillation. Use of the MCPR Safety Limit as the design criterion is conservative because fuel cladding damage is not likely to occur during brief periods of departure from nucleate boiling followed by the quenching that occurs during BWR density wave oscillations. Thermal-hydraulic testing has confirmed the conservatism of the MCPR Safety Limit under these conditions.

To demonstrate that the MCPR Safety Limit is not violated during oscillations, a methodology has been developed which relates LPRM response to the thermal-hydraulic response of the limiting fuel bundle in the core during oscillations. The uncertainties in this relationship, and the range of initial plant parameters that impact fuel thermal margin, must also be considered.

Both the prevention and detection and suppression methodologies must accommodate differences in fuel bundle designs, reload core designs, and operating strategies. The GE/BWROG approach accomplishes this by using conservative analyses and requiring reload verification of certain cycle-specific parameters when necessary.

4.3 SOLUTION DESCRIPTIONS

Summary descriptions of all long-term solutions considered by the BWROG follow. Five of these solutions, Options I-A, I-C, I-D, III and III-A, are described in more detail in Appendix A.

Solution descriptions for Options I-A, I-B, I-C, I-D, II, and III were provided previously in References 3 and 4. Options I-B and II have not changed substantially since the previous report and are therefore not included in this report. This report recognizes that alternate designs which use the methodology described in Sections 5.0 and 6.0 may be developed later to improve the sensitivity to instabilities or to further reduce the possibility of a plant scram from a false trip signal. Additionally, all common analytical methodology sections are now consolidated in Sections 5.0 and 6.0, and are not repeated in the solution descriptions.

All Option I solutions have the common feature of restricting operation in a predefined region of the power/flow map. Option III-A has not been previously documented, but is a variation on the use of individual LPRMs for detecting instabilities.

4.3.1 Option I-A: Regional Exclusion

The regional exclusion option is designed to prevent operation in the high power/low flow region of the power/flow map by initiating an ASF upon entry into the region. Analytical methodology described in Section 5.0 is used to define the power and flow boundaries of the region. The trip function is provided by a modified APRM flow-biased system which would result in either a scram or automatic exit from the region. A rod block would occur before the region is entered to provide a warning to the operator and prevent inadvertent entry resulting from control rod withdrawal. This option satisfies GDC-12 by preventing the onset of oscillations, and is further described in Appendix A.

4.3.2 Option I-B: Regional Exclusion With Stability Monitor

This solution is the same as Option I-A with an option to bypass the ASF and enter the exclusion region if a stability monitor shows sufficient decay ratio margin. The decay ratio margin would have to be sufficient to accommodate a flow reduction or loss of feedwater heating event inside the region. This option is considered viable, but not as desirable as other options. It is being pursued by the BWROG on a low priority basis, and is not discussed in-depth in this report and approval is not requested.

4.3.3 Option I-C: Administratively-Controlled Regional Exclusion With Modified APRM Flux Trip

This option uses an administratively-controlled exclusion region and a new APRM-based neutron flux trip system. The region will be identical to the region defined in Option I-A, and is administratively-controlled so that planned operation within the region is avoided. If an unplanned operational event results in the exclusion region being entered, the new neutron flux trip system will be automatically armed, and an oscillation that might occur would be automatically detected and suppressed before the MCPR Safety Limit is violated.

The Option I-C APRM neutron flux trip occurs at a specified level above the average APRM value. A trip is expected only if oscillations occur, or if normal neutron flux noise or some other non-stability perturbation creates a sufficient flux increase. Option I-C uses both administratively-controlled prevention and automatic detection and suppression to meet GDC-12. It has the potential operating advantage over Option I-A of not tripping every time the exclusion region is entered.

Recent estimates of the trip setpoint for this option were made using the detection and suppression methodology described in Section 6.0. These estimates indicate that the setpoints would be sufficiently near the neutron flux noise levels as to make this option less desirable than anticipated for some plant types. This option is further described in Appendix A.

4.3.4 Option I-D: Administratively-Controlled Regional Exclusion with Flow-Biased APRM Neutron Flux Scram

This option uses both administratively-controlled prevention and automatic detection and suppression to assure compliance with GDC-12. It is applicable to four or five U.S. BWRs that have relatively tight fuel inlet orificing. The solution uses a flow-biased APRM neutron flux scram system. The inlet orificing results in core-wide oscillations being the dominant mode for these units.

During planned operations, GDC-12 compliance is accomplished by administratively avoiding the region of potential instability (as defined by the Section 5.0 methodology), thereby preventing oscillations from occurring. If that region is entered as the result of an unplanned operational event, the flow-biased APRM neutron flux scram system provides direct detection and suppression of core-wide oscillations prior to exceeding the MCPR Safety Limit. Confirmation of appropriate protection for the low probability regional oscillations will be demonstrated using the detection and suppression methodology described in Section 6.0. This option is described further in Appendix A.

4.3.5 Option II: Quadrant APRM (BWR/2)

This option demonstrates that the existing quadrant-based APRM system of the BWR/2 plant types will initiate a reactor scram early enough to avoid violating the MCPR Safety Limit if oscillations should occur. The BWR/2 APRM system is unique in that LPRM instrument assignments to the APRMs are arranged in separate quadrants of the reactor. BWR/2s, therefore, have a substantial APRM response to a postulated regional oscillation. The instrumentation design, coupled with the low BWR/2 power density, readily supports a detection and suppression method of meeting GDC-12.

The analyses confirming the adequacy of this approach are similar to the other detection and suppression options and are described in depth in Appendix C of Reference 3. Plant specific submittals will be made to justify the Quadrant APRM system for BWR/2s.

4.3.6 Option III: LPRM Based Oscillation Power Range Monitor

This option, designated an Oscillation Power Range Monitor (OPRM), uses a microprocessor to monitor groups of LPRM signals. The grouping of LPRM signals and related system description information is described in more detail in Appendix A. Upon identification of neutron flux oscillations characteristic of a thermal-hydraulic instability, the system initiates an ASF that suppresses the oscillation. The system uses an algorithm which contains sufficient logic to prevent actuation by most or all non-instability plant events. The ASF is automatically bypassed at high flow or low power to avoid spurious actuations.

Detection and suppression compliance with GDC-12 will be demonstrated for all expected modes of oscillations, using the analytical methodology described in Section 6.0. By taking advantage of the strong response associated with a local power-based detection system, the system will be designed to trip only if a true thermal-hydraulic oscillation occurs; spurious or noise related signals should not actuate an OPRM trip. No restriction on power and flow operations will be required.

4.3.7 Option III-A: Alternative LPRM-Based System

This option, designated a LPRM-Based System (LBS), is very similar to Option III. It also uses a microprocessor to monitor groups of LPRM signals and initiates an ASF upon identification of neutron flux oscillations characteristic of a thermal-hydraulic instability. The main difference between Options III and III-A is in the number and grouping of LPRM signals in the various reactor protection system channels. Details of the Option III-A design concept are contained in Appendix A. Similar to Option III, detection and suppression compliance with GDC-12 is demonstrated using the methodology described in Section 6.0.

5.0 REGIONAL EXCLUSION LICENSING METHODOLOGY

The objective of the Regional Exclusion Licensing Methodology is to define a power/flow region where instability can occur. The boundary of this exclusion region is established through the use of an analysis procedure which is demonstrated to be conservative relative to expected operating conditions. This procedure does not attempt to define input values which are individually bounding with respect to stability, but uses a combination of inputs which together yield calculated decay ratios that are conservative relative to expected operating conditions.

In addition to steady-state operating conditions, operational events may result in unstable conditions. Therefore, a set of event-based calculations has been performed to confirm that the procedure adequately addresses anticipated operational occurrences. The limiting events analyzed are core flow reduction and loss of feedwater heating (LOFH).

This approach may be used as a solution in its entirety, where the exclusion region boundary is enforced by an ASF that will result in exiting the exclusion region upon entry. This approach may also be used to define a region outside of which automatic protective functions, designed to detect and suppress oscillations, are not required to be operational. Finally, this approach may be used to define a region where extra precautions may be warranted, or a region that is to be administratively avoided to provide an additional level of protection for a solution.

5.1 STABILITY CRITERIA

Calculations of core and channel decay ratios will be performed using the FABLE/BYPSS code and compared to stability criteria to define the exclusion region boundary. The FABLE/BYPSS code is a frequency domain code which is used to calculate the channel and core decay ratios. This model is described in Reference 5. The FABLE/BYPSS code has been qualified against test data using best estimate inputs to represent the plant operating conditions. The qualification showed good agreement at high decay ratios with an overall

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conservative bias. The bias was examined as a function of power, flow, and power density. A bias correction was then applied to the calculated values to determine a best estimate decay ratio. Results of the qualification are shown in Figure 5-1. Decay ratios calculated by this procedure are accurate to within a standard deviation of 0.08. A model uncertainty of 0.2 was applied to the calculation of core and channel decay ratios. This is an uncertainty of more than two standard deviations and is consistent with NRC approved uncertainties for licensing calculations using the FABLE code (References 6 and 7). The wide range of possible operating conditions are addressed by the selection of input conditions for the analysis (Section 5.2).

The FABLE/BYPSS code is used to directly calculate both core-wide (in-phase) and channel decay ratios for various modes of instability. Post-event analyses of the Garigliano, Vermont Yankee, Caorso, and Leibstadt stability tests and the LaSalle Unit 2 operating event have been used to establish a relationship between core and channel decay ratios (Figure 5-2). Each data point in this figure represents a limit cycle oscillation in the mode specified. Regional oscillations have occurred for FABLE/BYPSS calculated core and channel decay ratios less than 0.8.

To better understand regional oscillations, a separate frequency domain analytical model was developed which included a power feedback transfer function for individual channel hydrodynamic calculations. This model was used to estimate the regional decay ratio by simulating the power feedback from a group of channels. This feedback, when combined with a single channel hydrodynamic calculation, generates a decay ratio indicative of regional instability. This model was benchmarked against the above test data with good results. Using this model, the combination of core and channel hydrodynamic decay ratios which could potentially result in regional oscillations was mapped (Figure 5-3). From the results, for channel decay ratios less than 0.5 the effective channel decay ratio when the power feedback from surrounding channels was included was never greater than 1.0, indicating a threshold below which regional oscillations are not expected to occur.

Based on FABLE/BYPSS qualification to test data (Figure 5-1), Caorso and Leibstadt test data, and the estimated regional decay ratio calculations (Figures 5-2 and 5-3), Figure 5-4 was developed as the criteria for determining the potential for the various modes of instability based on FABLE/BYPSS calculated decay ratios. The cross-hatched region of the figure represents a region of potential instability. The lower boundary of this region is used as the stability criterion. Core and channel decay ratios at or below this lower boundary are considered to meet the criteria. Those conditions that lie above the lower boundary do not meet the criteria.

5.2 REGION BOUNDARY DEFINITION PROCEDURE

To determine a region boundary, FABLE/BYPSS calculations are performed over a range of power/flow conditions to determine a line of constant stability margin as defined by the stability criteria. Inputs and calculational procedures are chosen to collectively provide conservative results relative to stability. As such, some inputs are best estimate and others are conservative. The following sections describe the inputs for the FABLE/BYPSS procedure.

5.2.1 Void Coefficient

The most negative point model nuclear void coefficient (in terms of nuclear void coefficient/delayed neutron fraction) in the cycle is used. This void coefficient is based on a representative core and fuel design for the specific plant group being evaluated. The void coefficient is transformed into a moderator density reactivity coefficient for input to FABLE. Since this void coefficient will not necessarily correspond to a point in the cycle which produces the least stable condition based on other input parameters (e.g., power distribution), this is a conservative input. Since void coefficient may vary as a function of core and fuel designs, sensitivity studies are performed to determine the sensitivity of the region boundary to these changes.

5.2.2 Thermal-Hydraulics Data

Standard design values for thermal-hydraulics data are used in the analysis. These values are consistent with GE methods for other transient and accident analyses and are necessary to ensure consistency between the various analytical calculations performed for a stability analysis (e.g., nuclear and thermal-hydraulic).

5.2.3 Axial Power Shapes

(1) Hot Channel Decay Ratio

The axial power shapes for calculation of the maximum channel decay ratio are shown in Figure 5-5. Sensitivity studies show that the channel decay ratio is greater with a bottom-peaked axial power shape. The hot channel power shapes shown in Figure 5-5 conservatively bound expected operating conditions. The axial power shapes assumed for the hot channel are dependent on plant conditions. For forced circulation operation that is representative of startup conditions, a highly bottom peaked axial power shape is assumed. For natural circulation operation resulting from the trip of both recirculation pumps, a somewhat less severe bottom-peaked power shape is assumed, since the initial high power conditions have less peaked axial power shapes. For operation at relatively high power/flow conditions, a less peaked power shape is also used to reflect the expected range of conditions. Figures 5-6 through 5-9 compare the hot channel axial power shape assumed in the procedure with actual power shapes encountered during instabilities at Caorso, Leibstadt and LaSalle Unit 2.

(2) Core Decay Ratio

FABLE/BYPSS sensitivity studies for core decay ratio show that one of the limiting axial power shapes for core stability is a flat shape. The end-of-cycle (EOC) Haling power distribution at rated power/flow conditions (all control rods withdrawn) has a relatively flat shape compared to other exposures. Therefore, the EOC Haling full power core average axial power distribution is chosen for the core decay ratio calculations at all power/flow conditions with forced circulation. As core flow is reduced, the axial power distribution will tend to shift towards the bottom of the core and the use of a full power/flow Haling power shape will tend to be overly conservative. Therefore, for conditions at natural circulation flow, an EOC Haling calculated at natural circulation is used. Figures 5-10 through 5-12 show examples of the core average axial power distributions, with some comparisons to actual plant conditions during instabilities (Caorso, Leibstadt and LaSalle Unit 2).

The axial power shapes (hot channel and core average) are independently selected to provide conservative estimates of the channel and core decay ratios, even though the combination of power shapes is very unlikely (i.e., bottom-peaked channel with a flat core average power shape). Because the stability criteria are based on a combination of core and channel decay ratios, simultaneously maximizing both decay ratios is a conservative assumption.

5.2.4 Radial Power Distributions

A minimum of eight channel groups are used to model the radial power distribution. In general, one group is used for the peripheral bundles, six groups for the average channels, and one group for each hot channel for each fuel type. The radial power distribution is generated by the 3D BWR Core Simulator Code (Reference 8) based on an EOC Haling (all control rods withdrawn) condition. The number of bundles in each average channel group is determined to ensure that the total power is evenly distributed among the average channel groups. The average channel groups are comprised of channels of the same fuel type. The radial peaking factor for the hot channels is chosen to bound those calculated from the EOC Haling condition. Since radial peaking factor may vary as a function of core and fuel design and operating strategy, sensitivity studies are performed to determine the variation of the region boundary as a function of radial peaking factor.

5.2.5 Pellet-Clad Gap Conductance

Core average pellet-clad gap conductances are determined for each fuel type at the appropriate core thermal power condition using currently approved licensing models. A multiplier (1.6 for gap conductances calculated with the current licensing model) is applied to the gap conductance to provide a value consistent with models used during the comparison of FABLE/BYPSS to test data.

5.2.6 Other Inputs

Additional required inputs such as plant heat balance data, recirculation loop resistance and fuel physical parameters and material properties are based on standard design values.

5.2.7 Conservatism of Procedure

The Region Boundary Definition Procedure along with the criteria defined in Section 5.1, provides a conservative method for predicting an exclusion region. Results generated using the procedure have been compared to previous stability tests and shown to provide a conservative estimate of the core and channel decay ratios calculated using best estimate inputs of the actual measured plant conditions. For the Vermont Yankee Cycle 8 stability tests, the Peach Bottom Cycle 3 stability tests, the Caorso instability event in June 1982 and the Leibstadt Cycle 1 stability tests, the procedure always resulted in conservative core and channel decay ratios (average of 0.20 higher decay ratio). In addition to these demonstrations of the procedure conservatism, confirmation calculations have been performed for a BWR/6 plant (Section 5.4) to demonstrate that, under more realistic combinations of input conditions, the region boundary defined by the procedure provides margin to potential instabilities.

5.3 APPLICATION OF REGION BOUNDARY METHODOLOGY

Stability is dependent on many core and fuel parameters, as well as operational strategies that may affect power distribution. Those parameters that have the most significant effect on stability have been identified by various sensitivity studies performed over the years. Some of these parameters, specifically axial power distribution, have been conservatively specified in the procedure to eliminate the need to perform additional sensitivity studies. Other parameters such as void reactivity coefficient, radial peaking factor and fuel assembly design may still vary from plant to plant and cycle to cycle. To develop a generic basis for the definition of exclusion regions, plant groups are defined which share a variety of common features. In general, these plant groups closely follow the BWR product lines (e.g., BWR/3) because of their similar features. A representative plant is chosen from the plant group to form the basis for the generic region boundary definition for the particular plant group. Sensitivity studies are performed to allow other plants within the group to apply the same generic boundary, with modifications to the boundary where appropriate to account for differences in plant, fuel, and core designs.

For each plant group, a set of calculations is performed for the representative plant to define the location of the boundary. This is anticipated to require calculations at approximately three to four power/flow points along the boundary per plant group. The location of the boundary is defined as the collection of power/flow points at which the procedure defined in Section 5.2 produces a combination of core and channel decay ratio which meets the stability criteria (Figure 5-4). Typically, calculations will be performed along a constant rod line, at successively lower core flows until a point is found that meets the criteria of Figure 5-4. The region boundary point along this rod line may be determined by interpolating between two analyzed points, one below the stability criteria and one above the criteria of Figure 5-4. Additionally, the two points should be separated by no more than 5% of rated core flow to ensure reasonable linearity for interpolation. A similar procedure may be used by analyzing points with successively higher power, at constant core flow. Again, interpolation may be used provided the two analyzed points straddle the criteria of Figure 5-4 and are separated by no more than 5% power. An example application of the methodology has been performed for the BWR/6 plant group (Table 5-1), with the Perry plant chosen as the representative plant for analysis.

5.3.1 BWR/6 Region Boundary Definition

The important stability characteristics of the Perry plant compared to the other BWR/6 plants in the U.S. are shown in Table 5-1. Since fuel design, void coefficient, and radial power distribution may vary from cycle to cycle, these parameters must be considered separately when determining the applicability of a generically-determined region boundary. In general, the important stability features are common to the BWR/6 plants and Perry is a representative plant. The region boundary calculations were performed for two cycles of operation at Perry to cover the range of potential void coefficients that may be expected as a plant operates from early cycles to equilibrium cycle conditions. Cycle 2 and a hypothetical equilibrium cycle were evaluated for Perry.

(1) Perry Cycle 2 Evaluations

The Cycle 2 evaluations were based on the actual Perry as-loaded core which contains GE 8x8 fuel. EOC2 Haling power shapes were generated at rated conditions using the GE 3D BWR Simulator. These power shapes are used in the radial power distribution and core average axial power distributions per the procedure defined in Section 5.2. Figure 5-13 shows the full power Haling core average axial power shape which is used for the average channel power shapes when evaluating conditions at forced circulation that are generally expected during startup. Figure 5-13 also shows the calculated core average axial power shape that results from a flow runback to natural circulation from the full power Haling condition. This axial power shape is used for the average channels when evaluating natural circulation conditions. The most negative void coefficient during the cycle is chosen for all analyses and occurs at EOC-2000 MWd/ST.

For Cycle 2, there are two fuel types and, therefore, nine channel groups are used in the analysis. The nine channel groups comprise two hot channels (one for each fuel type), six average channels (three per fuel type) and one peripheral channel. The number of fuel bundles for each average channel group is chosen to ensure that each channel group has the same total integrated power.

The first set of calculations was performed along a high rod line, at points 1 and 2 shown in Figure 5-14. For these forced circulation conditions, the hot channel axial power shape is shown in Figure 5-5. The average and peripheral channels use the EOC Haling core average axial power shape at rated power, as calculated by the GE 3D BWR Simulator (Figure 5-13). The core and channel decay ratios for these two conditions are shown in Table 5-2. Similar calculations were performed along a lower rod line at points 3, 4, 4A, and 4B shown in Figure 5-14. These results are also summarized in Table 5-2.

The last set of calculations was performed at natural circulation conditions at points 5 and 6 shown in Figure 5-14. For these conditions, the EOC Haling core average axial power shape at natural circulation conditions was used for the average and peripheral channels. The hot channel axial power shape is also different from the assumption for the forced circulation calculations (Figure 5-5). The results of these calculations are also summarized in Table 5-2.

The results of the Cycle 2 region boundary calculations relative to the stability criteria defined in Section 5.1 (Figure 5-4) are summarized in Figure 5-15. The region boundary is determined from the intersection of the results with the criteria limits. For the Cycle 2 results, point 1 is chosen to define the region boundary for the high rod line. For the lower rod line and natural circulation, the region boundary is determined by interpolation between points 4 and 4A, and points 5 and 6, respectively. The region boundary can therefore be defined for Cycle 2 as the line drawn through these points. Figure 5-16 shows the Cycle 2 boundary for Perry.

(2) <u>Perry Equilibrium Cycle Evaluations</u>

A projected equilibrium cycle for Perry was evaluated containing all GE 8x8 fuel. The same basic procedure was used to perform the equilibrium cycle calculations as was used in the Cycle 2 analysis. Figure 5-17 and Table 5-3 summarize the points analyzed for the equilibrium cycle. The decay ratios are compared to the stability criteria in Figure 5-18 and the region boundary is determined by interpolation between points 7 and 8, 10 and 11, and 12 and 13. The region boundary defined by the equilibrium cycle analysis is shown in Figure 5-19.

5.4 REGION BOUNDARY CONFIRMATION

The procedure defined in Section 5.2 uses a combination of best estimate and conservative inputs to generate conservative core and channel decay ratios relative to the stability criteria defined in Section 5.1. The objective of the procedure is to define a region boundary outside of which the probability of oscillations is acceptably low. To confirm that the procedure is conservative, a series of calculations has been performed using actual combinations of inputs from predicted reactor operating conditions. These conditions cover a wide range of potential operating states that would be expected to occur for a plant. The conditions include startup operations, flow runbacks from full power operation and loss of feedwater heating events that are initiated near the region boundary.

During startup, control rods are withdrawn to establish a pattern that is consistent with the pattern expected at rated power. In general, these control rod patterns are established at low core flows to allow the maximum flexibility in obtaining the rated control rod pattern. During such operations, it is expected that quasi-steady-state conditions near the region boundary may be established and it must be demonstrated that these conditions are appropriately bounded by the procedure assumptions. Calculations have been performed using actual and predicted startup control rod patterns at various cycle exposures to simulate the power distributions and reactor conditions expected during startup operations.

The majority of an operating cycle consists of full power operation with control rod patterns that ensure all operating limits are satisfied. Should a reactor shutdown be required, or an inadvertent flow reduction occur that does not result in entering the exclusion region, operation near the region boundary may occur. Under these conditions, the power distribution is determined by the rated power control rod pattern and the power distribution change due to the flow runback. A set of calculations has been performed starting from full power conditions (equilibrium xenon) and simulating a flow reduction that ends near the region boundary. These calculations define the inputs for the stability analysis.

The final confirmation calculations that have been performed involve the potential for a loss of feedwater heating event (LOFH) that could occur while operating near the region boundary. Although in general only a small fraction of the cycle will result in operation near the region boundary, stability is known to be sensitive to the increase in inlet subcooling caused by loss of feedwater heating. For expected LOFH events near the region boundary (expected temperature loss defined to be 60°F), an evaluation was performed to determine the resultant decay ratios at the final operating conditions of the LOFH event. It was assumed that the event resulted in conditions that were near the region boundary but did not enter the exclusion region. Entering the region would result in initiation of an ASF or would enable the trip function of a detection and suppression system thereby providing automatic protection.

For steady-state and event-based calculations used to confirm the restricted region boundary, the same basic procedure as outlined in Section 5.2 was used. However, the axial and radial power distribution and void coefficient were based on calculations using the GE 3D BWR core simulator code (Reference 8) at the conditions chosen for the analysis (i.e., control rod pattern, cycle exposure, etc.).

5.4.1 Startup Condition Evaluations

For BWR/6 plants, the startup path begins with the recirculation pumps on low speed, with the flow control valves (FCV) at their maximum open position. Control rods are withdrawn until sufficient power and feedwater flow is established to clear interlocks designed to prevent pump cavitation should core flow increase beyond a minimum value. These interlocks are typically set near 30% of rated core thermal power. Once these interlocks are cleared, the FCVs are closed to their minimum position and the associated recirculation pump is transferred to high speed. The location of the region where these upshifts are performed, compared to the exclusion region boundary is shown in Figure 5-20. Five cases were performed at these conditions, covering Cycle 2 and equilibrium cycle conditions. Each case was evaluated by first determining a critical rod pattern at the defined conditions, assuming no xenon was present. This is representative of startup conditions. Control rod patterns were chosen to ensure that all thermal limits were met. The radial and axial power distributions were then calculated using the GE 3D BWR Simulator. The decay ratio results are summarized in Table 5-4 for the confirmation calculations performed at these conditions. The results are also shown in Figure 5-21. These results demonstrate that the stability criteria of Section 5.1 are met.

After the recirculation pumps have been shifted to high speed, the FCVs are opened until approximately 45-50% of rated core flow is attained. Control rods are then withdrawn until the desired rod pattern is achieved, the maximum rod line is reached, or thermal limits are reached. This condition is also shown in Figure 5-20. The same procedure was used to calculate the power distributions of these conditions as was used in the previous startup cases. The results are summarized in Table 5-4 and Figure 5-21. Again, all cases meet the stability criteria of Section 5.1.

5.4.2 Flow Runback Evaluations

The majority of an operating cycle is spent at rated power conditions and, therefore, this is a likely condition from which a flow reduction event may be initiated and ultimately result in operation near the exclusion region boundary. In general, flow reduction events are caused by recirculation pump trips (single or dual pump trips) or runbacks of the recirculation pump speed (BWR/3-5) or FCVs (BWR/5-6). It is possible that a single recirculation pump trip, flow runback in one loop, or partial runback of the flow in both recirculation loops could result in operation just outside the exclusion region boundary. These conditions near the exclusion region boundary are primarily determined by the initial full power operating conditions and the change in conditions caused by the flow reduction. Since full power xenon is present, the control rod patterns can be significantly different than those experienced during startup.

A set of conditions was simulated from full power, with various cycle exposures and initial core flows for the Perry Cycle 2 and equilibrium cycle cores described and analyzed in the previous sections. The Cycle 2 cases were evaluated using actual control rod patterns from plant experience. Control rod patterns were also developed for the equilibrium cycle based on standard core management practices, and were selected to ensure that all core operating limits were satisfied at the full power condition. The GE 3D BWR Simulator was used to establish the full power conditions, including equilibrium xenon. The xenon is then assumed to remain constant and the core flow reduced to a point just outside the exclusion region boundary. The power distribution at these final conditions was used as input to the stability analysis. The void coefficient was determined at the same cycle exposure as the power distribution.

The conditions analyzed are shown in Figure 5-20. The calculated decay ratios are summarized in Table 5-4 and in Figure 5-21, where they are compared to the stability criteria of Section 5.1. All of the analyzed conditions meet the stability criteria of Section 5.1.

5.4.3 Loss of Feedwater Heating Evaluations

During startup or shutdown from high power, the reactor will be operated with margin to the exclusion region boundary to reduce the probability of an inadvertent ASF initiation. It is possible during this time that a loss of feedwater heating event could result in an increase in core thermal power to a point just below the region boundary. This will change the power distribution and could potentially result in a less stable condition. To confirm that the stability procedure provides sufficient margin to account for the changes due to feedwater temperature transients, confirmation calculations were performed. The calculations assumed that operation begins near the region boundary and a decrease in feedwater temperature occurs (assumed to be 60°F, which corresponds to a feedwater temperature drop at rated power of approximately 100°F). The reduced feedwater temperature increases the core inlet subcooling resulting in a positive reactivity insertion and an increase in core thermal power.

The GE 3D BWR Simulator was used to calculate the initial conditions just prior to the LOFH event. Control rod patterns were chosen to ensure that all core operating limits were satisfied prior to the LOFH event. The Simulator was used to calculate the final core thermal power and power distribution based on the lower feedwater temperature. These final power distributions and the final power level were used in the stability analysis to determine the decay ratios. The void coefficient was determined at the same cycle exposure.

The LOFH events are assumed to begin from both startup conditions (xenon free) and conditions which result from a flow reduction from rated power. The stability analysis points (final conditions) are shown in Figure 5-20. The decay ratios are summarized in Table 5-4 and are compared in Figure 5-21 to the stability criteria of Section 5.1. All cases meet the stability criteria of Section 5.1.

5.4.4 Summary

The Region Boundary Definition Procedure described in Section 5.2 was developed to provide a conservative estimate of the region of the power/flow map that has the potential for thermal-hydraulic oscillations. This was accomplished by choosing a combination of best estimate and conservative inputs that, in many cases, were mutually exclusive. Comparisons to previous stability tests and events demonstrated that the procedure consistently predicted larger decay ratios when compared to predictions which used inputs based on actual plant conditions. To further confirm that the procedure provides a conservative estimate of reactor stability, calculations were performed for a wide variety of conditions that were representative of actual plant operation. In addition, conditions resulting from unplanned core flow reductions and feedwater temperature reductions were evaluated (Sections 5.4.1, 5.4.2, and 5.4.3). For all cases analyzed, the core and channel decay ratios were less than or equal to the stability criteria defined in Section 5.1. When combined with the previous calculations of instability events and tests, these calculations demonstrate that the Region Boundary Definition Procedure provides adequate conservatism for the expected range of plant operating conditions.

5.5 PLANT- AND CYCLE-SPECIFIC APPLICATION OF GENERIC REGION BOUNDARIES

The application of the Region Boundary Definition Procedure to a specific BWR/6 plant, Perry, is summarized in Section 5.3. Although this procedure could be individually applied to any plant, this analysis is intended to define a generic region boundary that similar plants can use. To confirm that the region boundary is applicable to another plant, a comparison of the major parameters (including core and fuel design) affecting stability must be made. If all parameters are within a defined range, the region boundary can be applied to the specific plant. If any parameter is outside the defined range, the region boundary can be modified to account for the variability of stability characteristics for the particular parameter.

This approach of defining a generic region can be applied to each plant group where a plant group is defined as a set of plants which are similar with respect to parameters important to thermal-hydraulic instability. Sensitivity studies can then be performed for a plant group, to define the range of acceptable parameters and determine any necessary modifications to the generic region boundary. The parameters that have been identified as key stability parameters which must be evaluated to determine the applicability of a generic region boundary are discussed in this section. The parameters are separated into those that are functions of fuel and core design, and those that are functions of plant design and operational strategies.

5.5.1 Fuel and Core Design Parameters

The effect of fuel and core designs on stability is described by the core and channel decay ratios. Additionally, the parameters which directly affect the decay ratios (e.g., channel pressure drop characteristics, fuel thermal time constant, moderator void reactivity coefficient, etc.) can be independently evaluated for their impact on stability. The following sections describe the procedures that may be used to confirm the acceptability of a design.

(1) Channel Decay Ratio

Use of the channel decay ratio as a parameter allows the consideration of many separate parameters to be combined, thereby simplifying the evaluation process. In addition, the channel decay ratio is a direct variable in the stability criteria of Section 5.1, and any change can be directly related to the criteria. The generic region boundaries are developed with a base fuel type with known channel decay ratio that is representative of current fuel designs. The characteristics of the base fuel type can also be used to define a set of fuel types whose stability characteristics are bounded by the base design. The generic region boundary will be applicable to fuel designs whose stability characteristics have been demonstrated to be bounded by the base design. Any future fuel design can be added to the range of acceptable designs by performing specific channel decay ratio calculations which demonstrate comparable stability performance.

For fuel designs that are not bounded by the base design or that do not have a channel decay ratio calculated for comparison to the base design, other alternatives are available to assess the relative stability characteristics. Sensitivity studies can be performed which vary the important fuel design parameters that affect channel decay ratio (e.g., two-phase to single-phase pressure drop ratio, number of fuel rods, fuel rod diameter, etc.). A response surface can be constructed from these results that describes the change in channel decay ratio as a function of the independent variables. The specific parameters for a design can be input into the response surface to determine the relative change in the channel decay ratio from the base design. This method is useful for designs with similar basic characteristics and may require updating to include sufficient variation in parameters to accommodate new fuel designs.

The response surface can be generated for several points along the exclusion region boundary (i.e., at the intersection of the maximum core flow and maximum rod line, and at natural circulation) and sensitivity studies can be performed to determine the necessary change in the location of the exclusion region boundary for a given change in channel decay ratio (e.g., for an increase in channel decay ratio of 0.10, the exclusion region boundary must be increased by 5% of rated core flow at the maximum rod line, and reduced by 5% rod line at natural circulation flow). These sensitivity studies can also be used to calculate the required change in the exclusion region boundary when direct calculations result in an increase in the channel decay ratio for a fuel design.

(2) Core Decay Ratio

The core decay ratio is affected by the fuel thermal time constant since changes in neutron flux affect the local void content through the fuel rod surface heat flux. The fuel thermal time constant is dependent primarily on the fuel rod diameter and the gap conductance. The timing and magnitude of this feedback are dependent on the fuel thermal time constant. The resulting magnitude of the void feedback is directly proportional to the moderator density reactivity coefficient which also has a direct effect on the core decay ratio. The base fuel and core design used to develop the generic exclusion region boundaries will define the base fuel thermal time constant and moderator density reactivity coefficient. Since these effect the core decay ratio, calculations of the core decay ratio for fuel designs other than the base design can be made and compared to the base design to determine their acceptability. Alternatively, as described above, a response surface can be defined that describes the change in core decay ratio as a function of the change in fuel thermal time constant and moderator density reactivity coefficient. Changes from the base fuel thermal time constant and moderator density reactivity coefficient can be translated into a change in core decay ratio, and subsequently the exclusion region boundary can be modified if necessary.

5.5.2 Plant Design and Operating Strategy Parameters

The operation of two different plants with the same fuel types can result in a range of core and channel decay ratios, depending on certain characteristics of the plant (e.g., inlet orificing, recirculation loop resistance, feedwater temperature) and operating strategies (e.g., high radial peaking factors to take advantage of low operating limits).

Therefore, in addition to comparisons of fuel designs, plant and operating strategy comparisons must be made to ensure the applicability of the generic region boundaries. The following parameters have been identified as important to stability and proposed methods for comparison to values used in the generic analysis are discussed.

(1) Power/Flow Ratio

In general, stability results are presented at power and flow states as a percent of the rated conditions. Two plants can be operating with the same power/flow condition as a percent of rated but the individual fuel bundles could be at different absolute values of power/flow ratio.

For operation at the same bundle flow, but higher absolute power, the channel decay ratio will be higher. Therefore, one of the sensitivities between plants within a plant group will be the absolute power/flow ratio. In general, within a plant group, the power/flow ratio will not vary significantly. Sensitivity studies will be performed to determine the change in core and channel decay ratios as a function of the absolute power/flow ratio. The generic region boundary will be defined with a base value that, in general, will bound the expected values for other plants within the group.

(2) Recirculation Loop Resistance

The recirculation loop in the FABLE/BYPSS methodology is modeled by a simple gain and time constant. These parameters are calculated for specific power and flow conditions based on the pressure drop characteristics of the recirculation loop. These characteristics may vary among plants because of differences in jet pump design, steam separator pressure drop characteristics, or external recirculation loop hydraulic differences. In general, these parameters are not expected to vary significantly among plants within a plant group. Sensitivity studies will be performed to determine the change in core and channel decay ratios as a function of these parameters. The generic region boundary will be defined with a base value that, in general, will bound the expected values for other plants within the group.

(3) Fuel Inlet Orifice Diameter

The largest component of the single-phase pressure drop is from the fuel inlet orifice. A wide variety of inlet orifice diameters exists in plants today. Because of the significant impact of the fuel inlet orifice diameter on channel decay ratios, plant groups will be defined with similar inlet orifice diameters. Within a plant group, the generic region boundary will be defined with a base value that will bound the expected values for the other plants within the group.

(4) Inlet Subcooling

Inlet subcooling affects both the core and channel decay ratio and will vary for plants within a plant group. The inlet subcooling is primarily dependent on the feedwater temperature and, in general, plants fall within one of two categories; those with 420°F rated feedwater temperatures and those with 360-385°F rated feedwater temperatures. The generic exclusion region boundary will be determined for a range of feedwater temperatures expected for the plant group.

In addition to normal feedwater temperatures, plants may also operate with feedwater heaters out-of-service (FWHOS) or with final feedwater temperature reduction (FFWTR). In general, FFWTR is performed at the end of cycle when the plant is operating at or near the rated rod line. Generic analyses have demonstrated that the core and channel decay ratios are not significantly different during these conditions and, therefore, FFWTR does not impact the exclusion region boundary when performed at the end of cycle at or above rated core flow. For FWHOS operation, the results are expected to be similar to those determined from confirmation calculations discussed in Section 5.4.3 for the LOFH event. Therefore, the Region Boundary Definition Procedure adequately covers these modes of operation.

(5) Radial Power Distribution

The radial power distribution directly affects both the core and channel decay ratios. The maximum radial peaking factor determines the hot channel power and the distribution of radial power affects the core decay ratio. Direct sensitivity studies can be performed to evaluate the sensitivity of channel decay ratio to maximum radial peaking factor. The generic region boundary will be generated for a given radial peaking factor that reasonably bounds expected plant operation for a plant group. The impact of any deviations from this base value will be estimated from the results of the sensitivity studies.

The radial power distribution has a more complicated effect on the core decay ratio, primarily through its impact on the total moderator density reactivity feedback. The Region Boundary Definition Procedure assumes the radial power distribution from EOC Haling conditions. Confirmation studies in Section 5.4 demonstrated that the overall conservatism of the procedure and stability criteria of Section 5.1 are sufficient to bound the expected variations in radial power distribution. Therefore, only the impact of the maximum radial peaking factor will be evaluated.

Table 5-1
BWR/6 PLANT GROUPING

	Clinton	Grand Gulf	Perry	River Bend
Power Density (kW/l)	52.4	54.2	54.1	52.4
Power/Flow Ratio (MWth/(Mlbm/hr))	34.2	34.1	34.4	34.2
Rated Feedwater Temperature (°F)	420	420	420	420
Maximum Rod Line (%)	120	120	120	105
Fuel Inlet Orifice Diameter (in)	2.43	2.43	2.43	2.43
Operating Cycle	3	5	3	4
Fuel Type	GE8x8	ANF9x9-5 ANF8x8	GE8x8	GE8x8

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Table 5-2

PERRY CYCLE 2 REGION BOUNDARY CALCULATIONS

Point*	Power/Flow (%/%)	Hot Channel Decay Ratio	Core Decay Ratio
	HIGH ROD LINE		
1	75.4/50.0	0.52	0.56
2	71.0/45.0	0.62	0.71
	MEDIUM ROD LINE		
3	61.7/50.0	0.36	0.48
4	54.7/40.0	0.53	0.72
4A	53.2/38.0	0.58	0.78
4B	51.7/36.0	0.64	0.86
	NATURAL CIRCULATION		
5	36.7/30.0	0.49	0.77
6	39.0/30.0	0.55	1.07

* See Figure 5-14 for definition of points.

Table 5-3

PERRY EQUILIBRIUM CYCLE REGION BOUNDARY CALCULATIONS

Point*	Power/Flow (%/%)	Hot Channel Decay Ratio	Core Decay Ratio
	HIGH ROD LINE		
7	75.4/50.0	0.49	0.74
8	72.9/47.0	0.55	0.82
9	71.0/45.0	0.59	0.89
	MEDIUM ROD LINE		
10	58.3/45.0	0.42	0.76
11	54.7/40.0	0.50	0.89
	NATURAL CIRCULATION		
12	31.0/30.0	0.39	0.66
13	35.0/30.0	0.44	0.81
14	36.7/30.0	0.47	0.88

* See Figure 5-17 for definition of points.

Table 5-4

PERRY CONFIRMATION ANALYSIS DECAY RATIOS

Point *	Exposure/Cycle	Final Power/Flow	Hot Channel Decay Ratio	Core Decay Ratio
PUMP UPSHIFT CONDITIONS				
A1	BOC2	37.0/35.0	0.44	0.22
A2	MOC2 **	39.3/34.0	0.51	0.52
A3	BOEC	38.5/34.0	0.51	0.47
A4	MOEC	45.5/38.0	0.39	0.66
A5	EOEC	41.7/36.0	0.21	0.71
MAXIMUM POWER DURING STARTUP				
B1	BOC2	74.5/50.0	0.35	0.25
B2	EOC2	74.8/50.0	0.38	0.55
B3	BOEC	75.3/50.0	0.32	0.37
B4	MOEC	75.1/50.0	0.39	0.59
B5	EOEC	62.5/45.0	0.35	0.75
FLOW REDUCTION EVENTS				
C1	BOC2 ***	63.1/45.0	0.32	0.51
C2	MOC2 ***	68.0/46.0	0.39	0.48
C3	EOC2 ***	68.0/46.0	0.40	0.61
C4	BOEC	60.0/42.0	0.34	0.60
C5	MOEC	72.0/48.0	0.31	0.66
C6	MOEC	64.9/45.5	0.35	0.70
C7	EOEC	59.0/43.5	0.32	0.74
LOSS OF FEEDWATER HEATER EVENTS				
D1	BOC2	37.3/35.0	0.46	0.26
D2	MOC2	39.3/34.0	0.44	0.47
D3	EOC2	68.5/46.0	0.44	0.62
D4	BOEC	74.8/50.0	0.33	0.36
D5	MOEC	72.4/48.0	0.35	0.65
D6	MOEC	45.5/38.0	0.44	0.71
D7	EOEC	59.5/43.5	0.30	0.73

* See Figure 5-20 for definition of points.
** Actual Cycle 2 conditions.
*** Based on Cycle 2 conditions at full power.

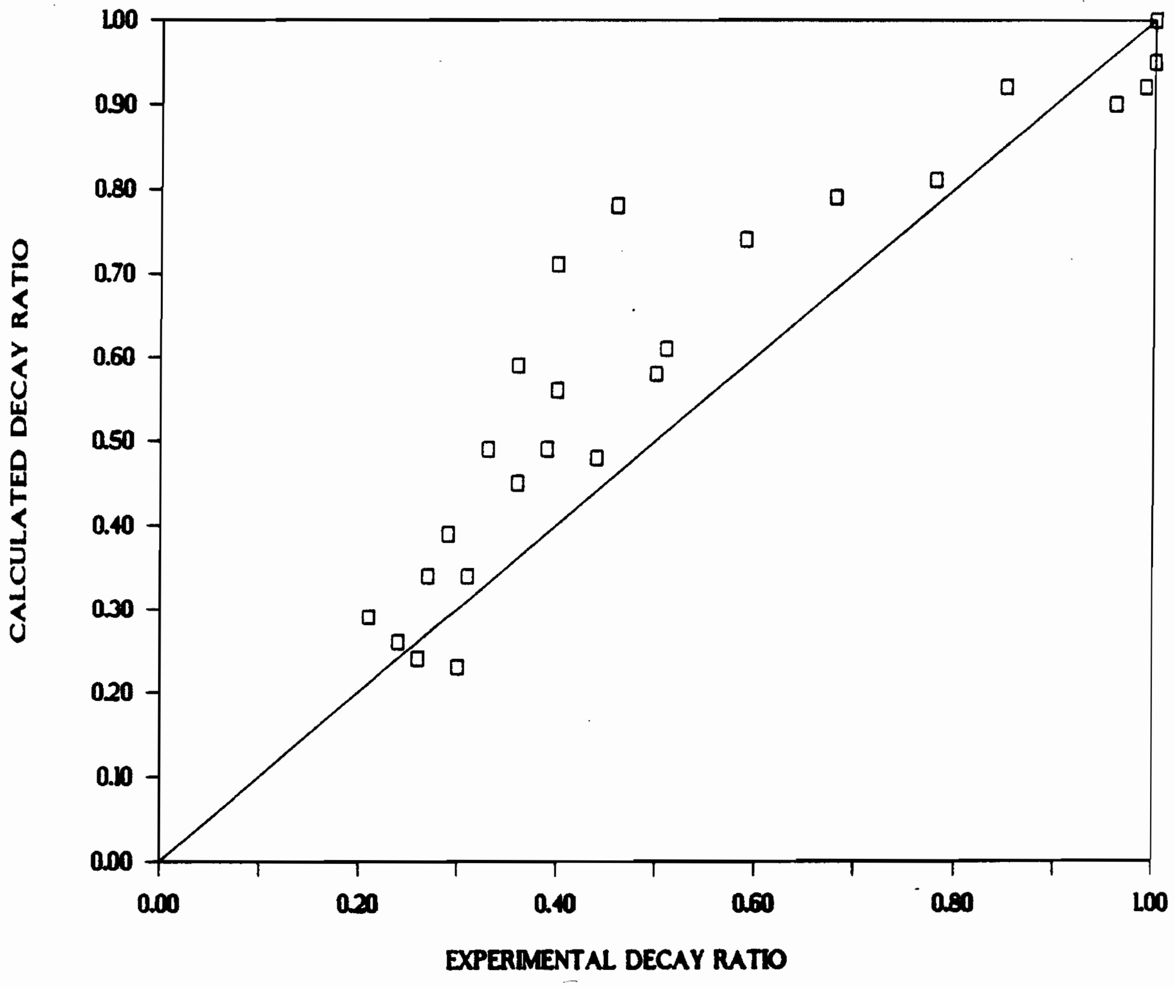

FIGURE 5-1. FABLE/BYPSS COMPARISON TO TEST DATA

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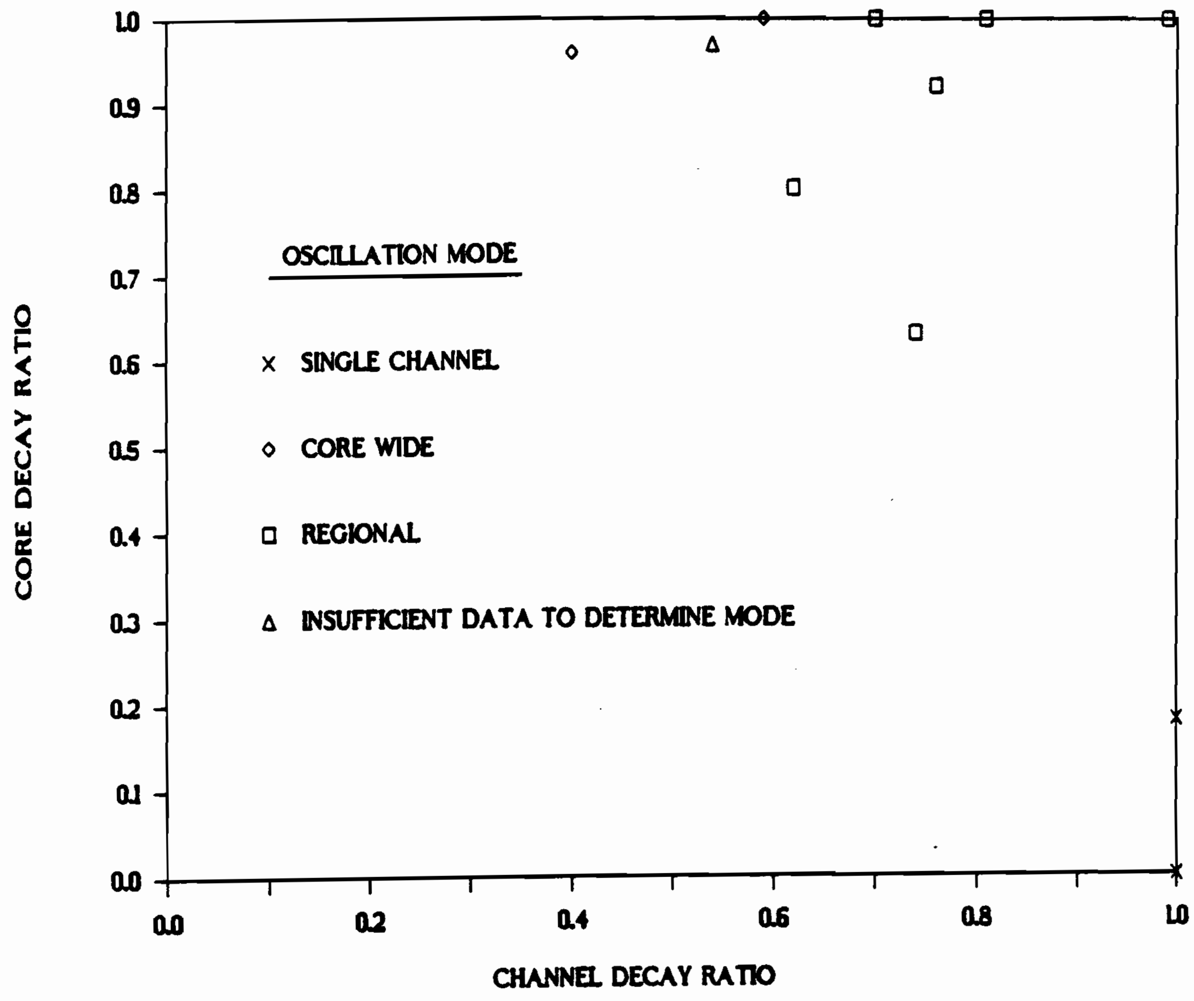

FIGURE 5-2. FABLE/BYPSS COMPARISON TO OSCILLATION MODES

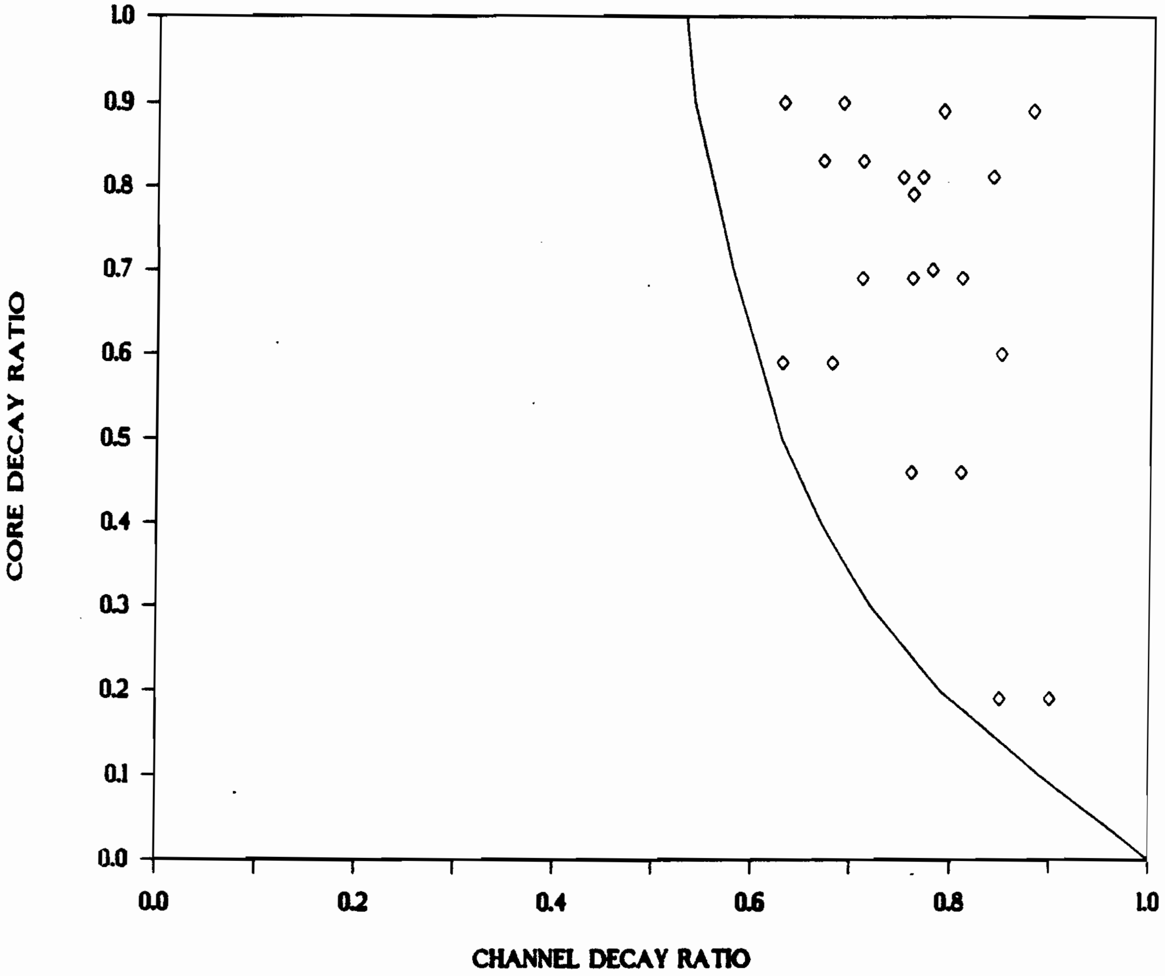

FIGURE 5-3. CORE/CHANNEL DECAY RATIOS RESULTING IN CALCULATED REGIONAL OSCILLATIONS

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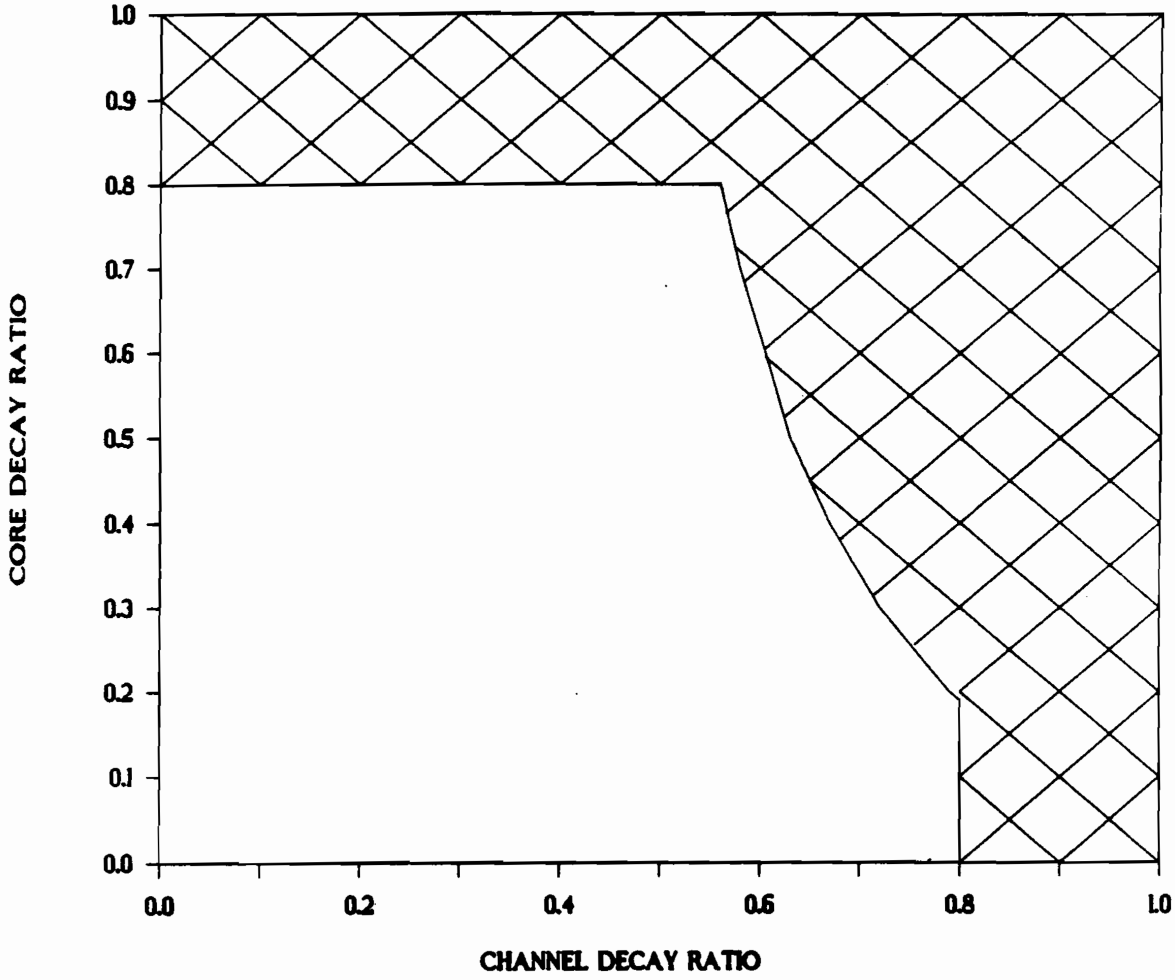

FIGURE 5-4. FABLE/BYPSS STABILITY CRITERIA

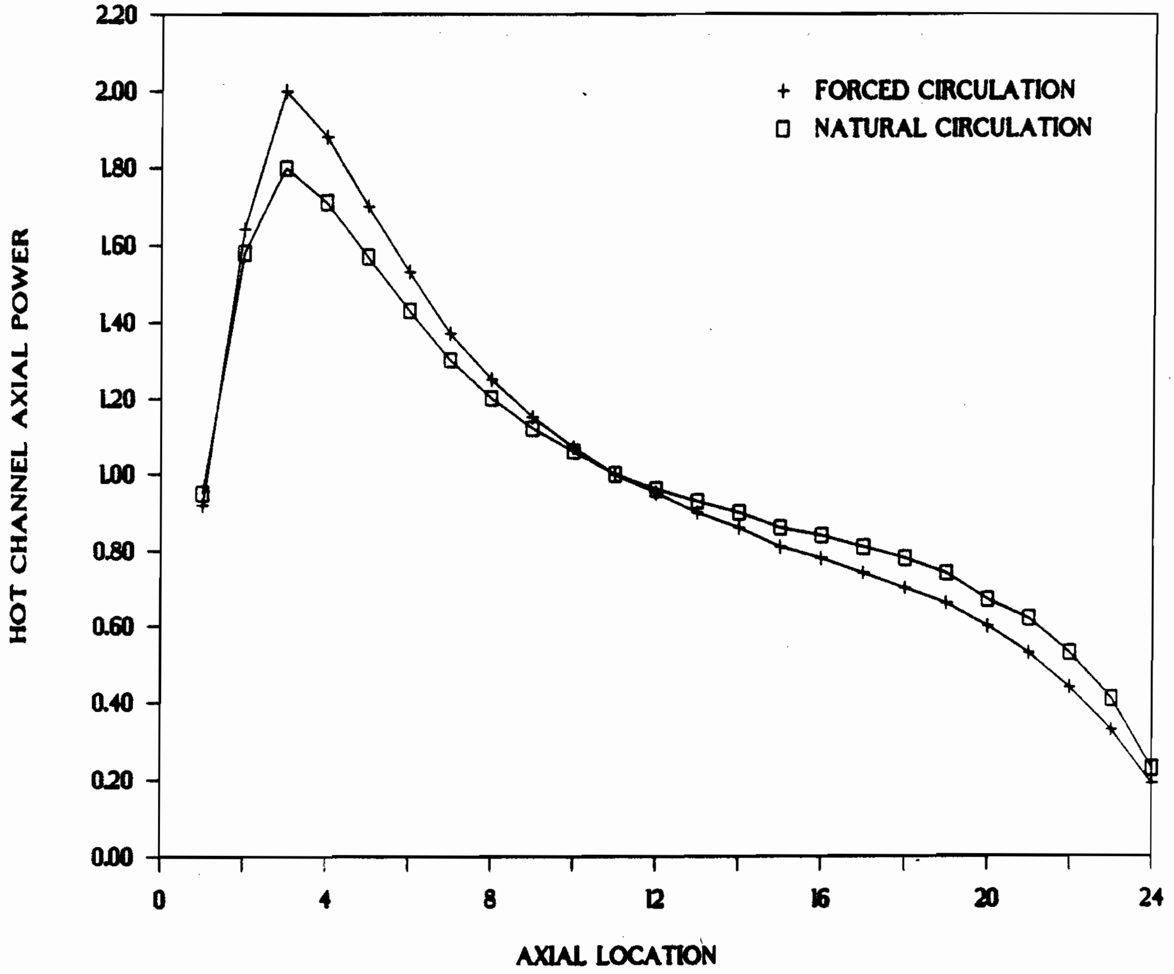

FIGURE 5-5. HOT CHANNEL AXIAL POWER DISTRIBUTION

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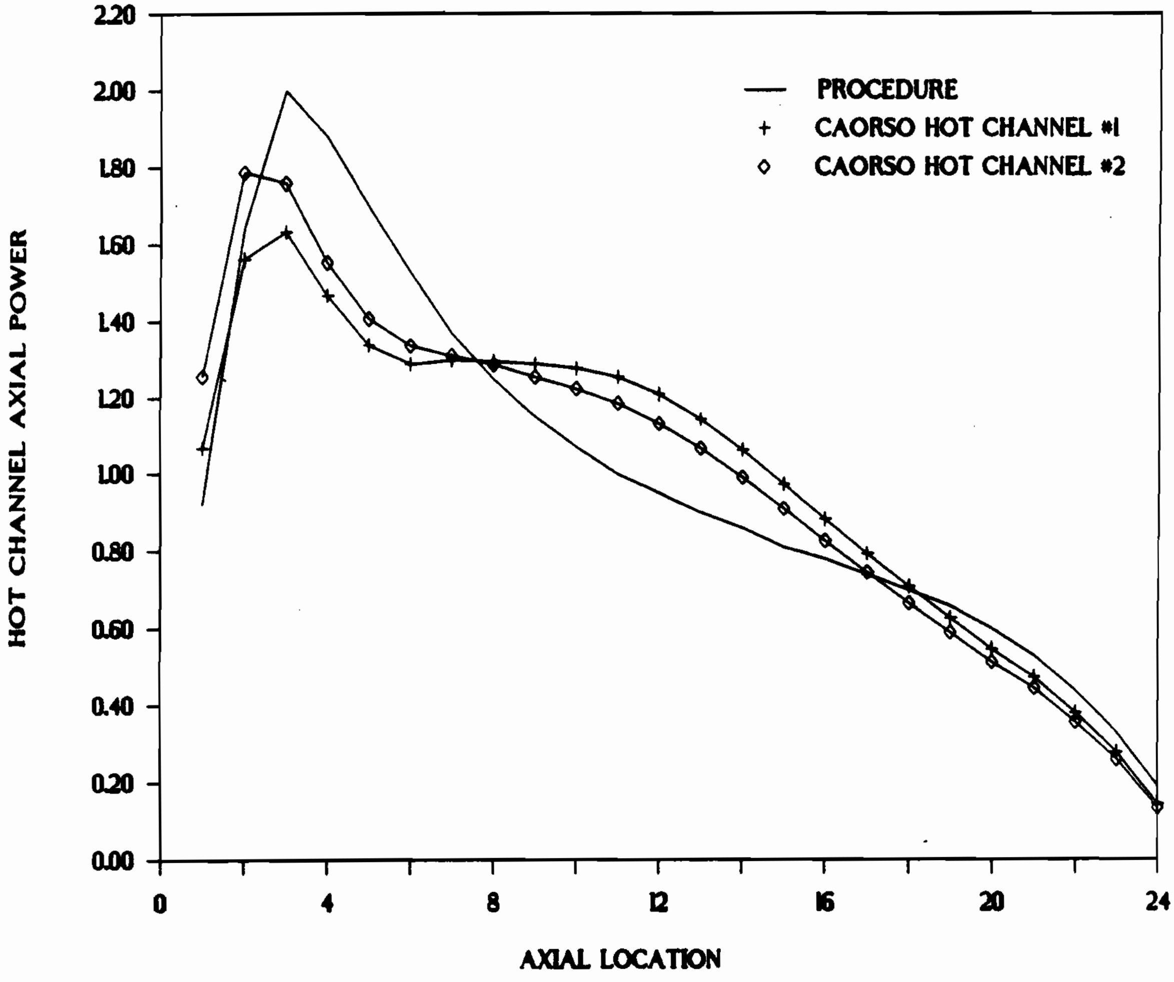

FIGURE 5-6. HOT CHANNEL AXIAL POWER DISTRIBUTION - COMPARISON TO CAORSO EVENT DATA

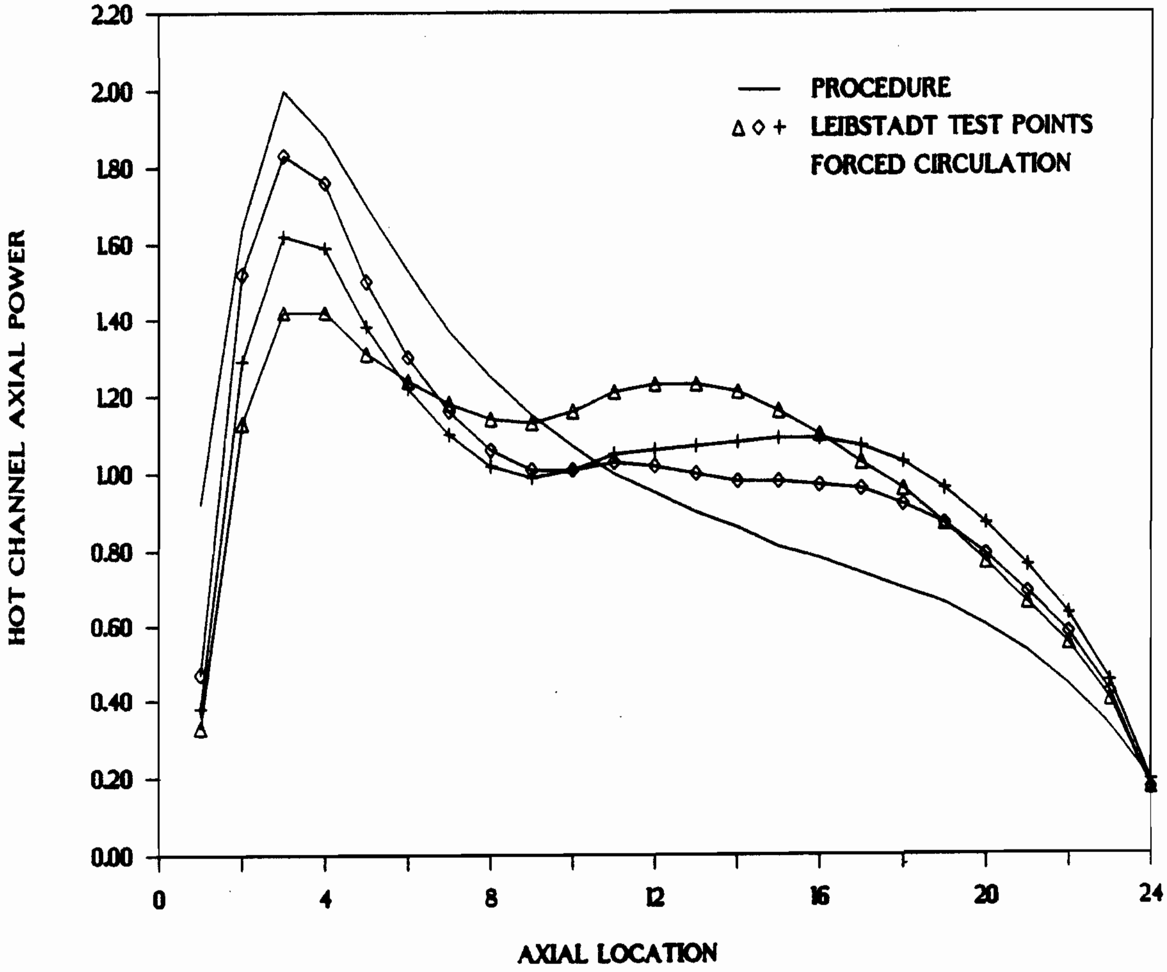

FIGURE 5-7. HOT CHANNEL AXIAL POWER DISTRIBUTION - COMPARISON TO LEIBSTADT TEST DATA

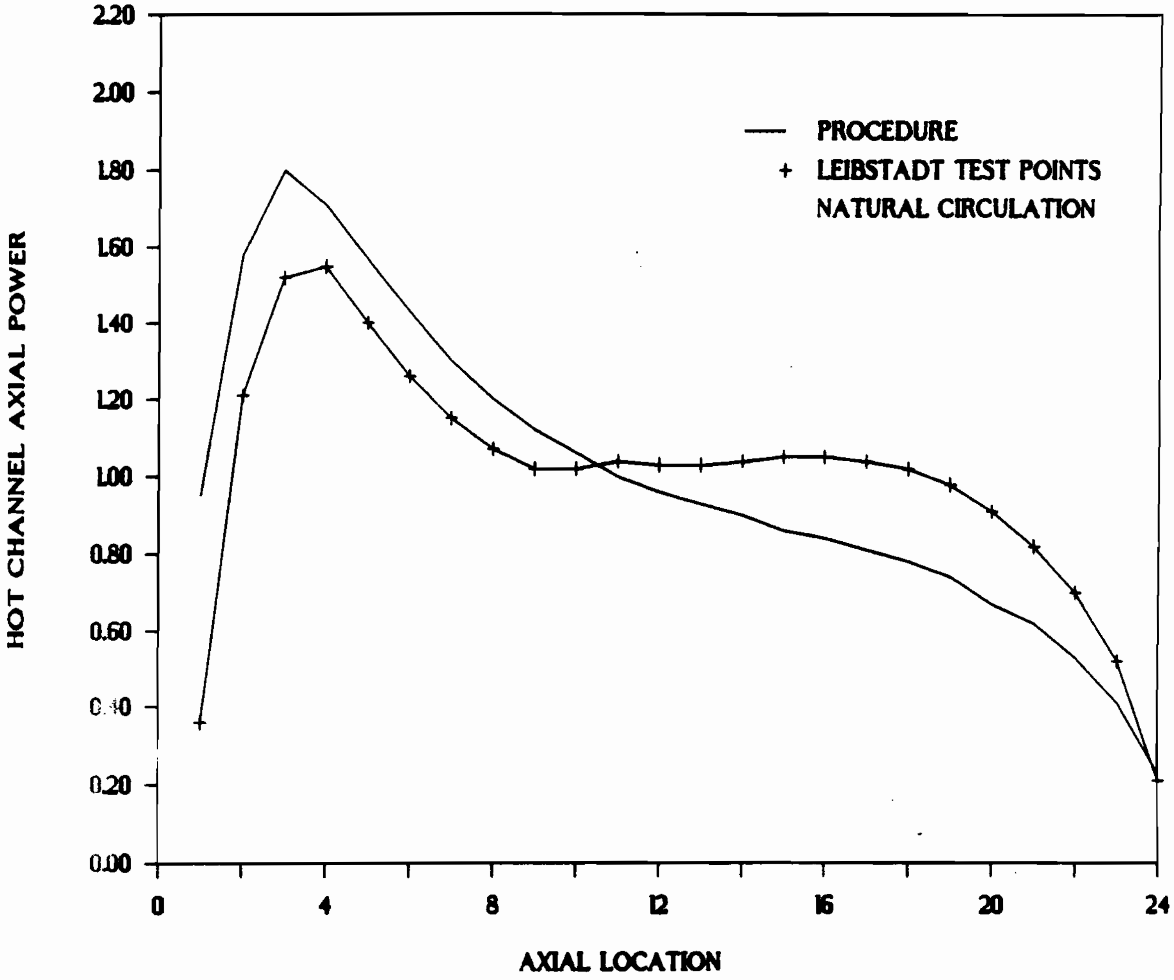

FIGURE 5-8. HOT CHANNEL AXIAL POWER DISTRIBUTION - COMPARISON TO LEIBSTADT TEST DATA

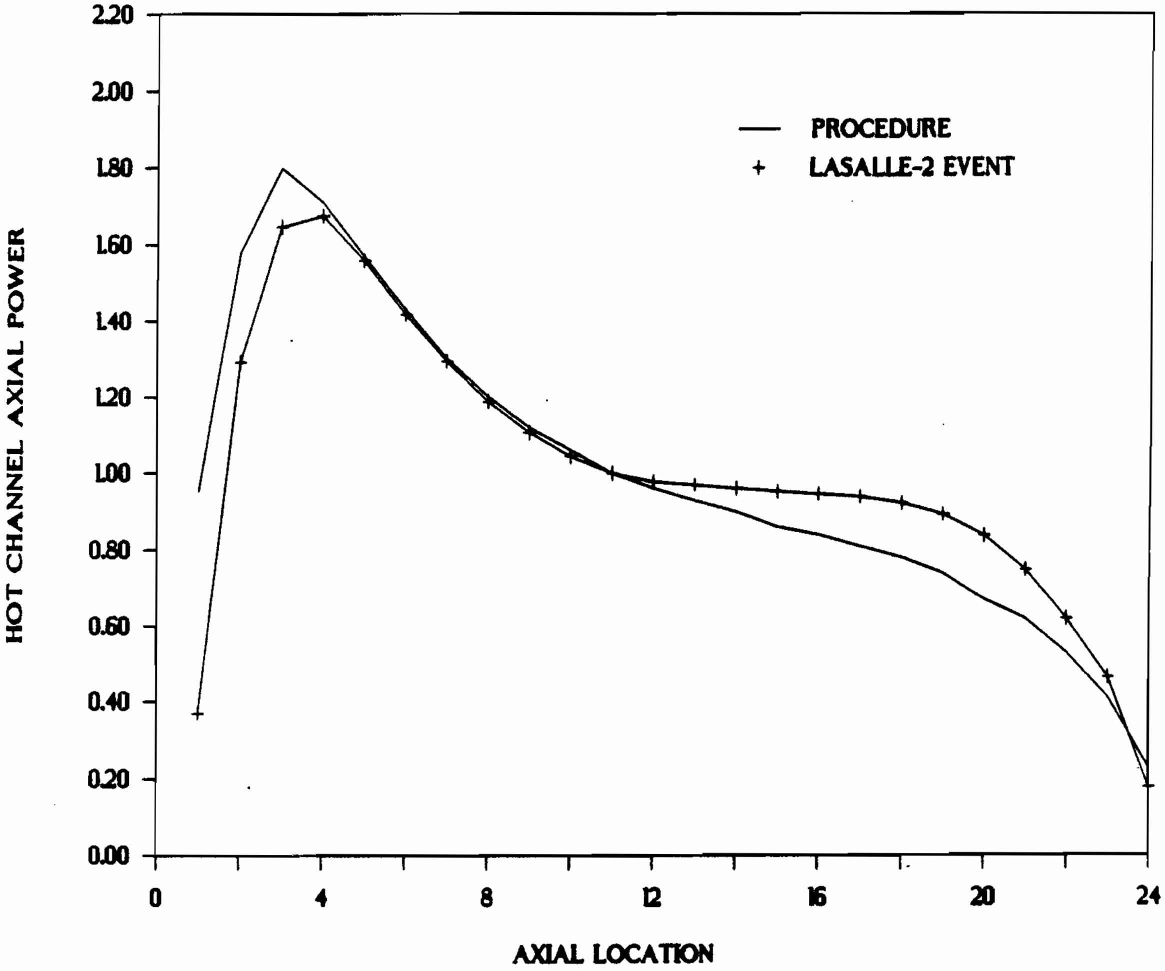

FIGURE 5-9. HOT CHANNEL AXIAL POWER DISTRIBUTION - COMPARISON TO LASALLE EVENT DATA

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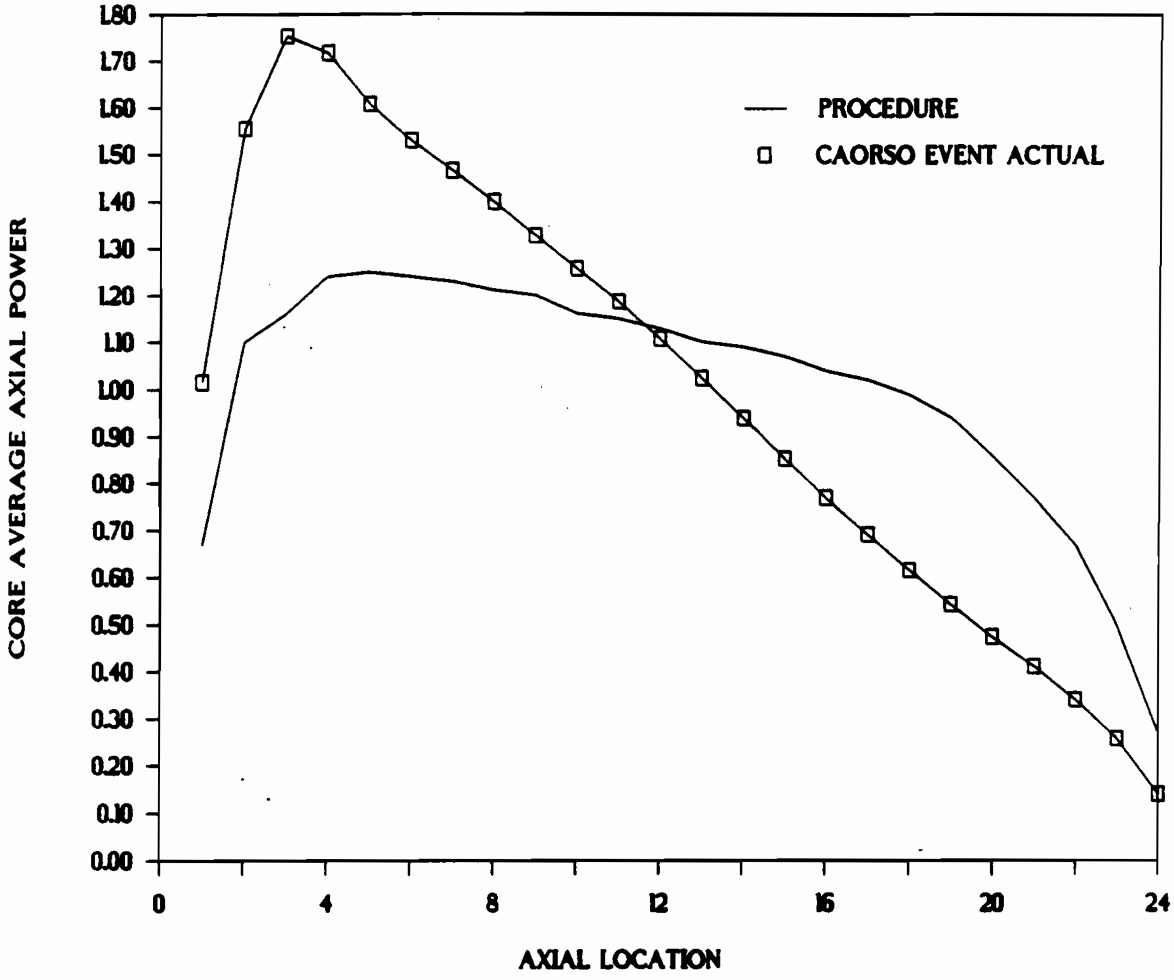

FIGURE 5-10. CORE AVERAGE AXIAL POWER DISTRIBUTION - COMPARISON TO CAORSO EVENT DATA

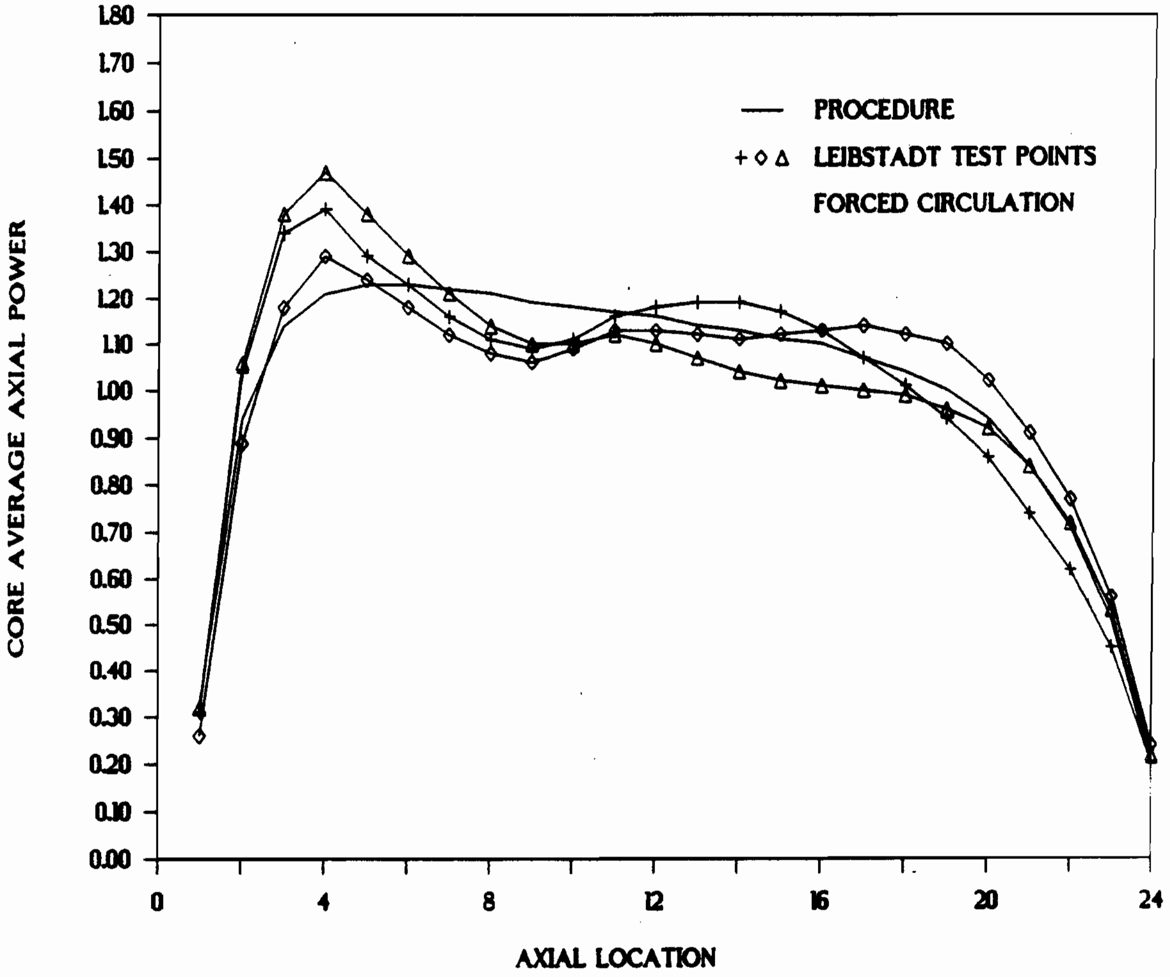

FIGURE 5-11. CORE AVERAGE AXIAL POWER DISTRIBUTION - COMPARISON TO LEIBSTADT TEST DATA

65

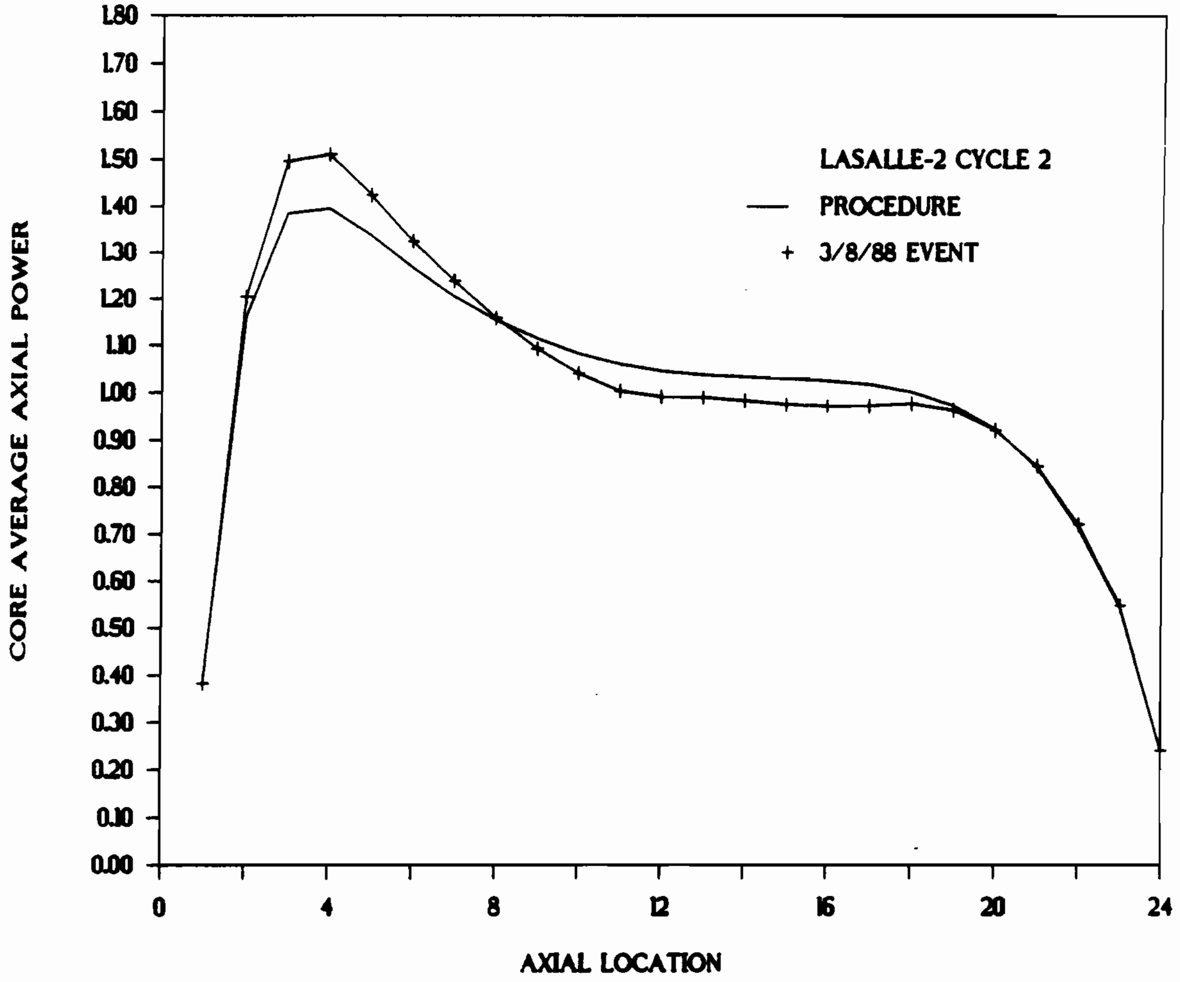

FIGURE 5-12. CORE AVERAGE AXIAL POWER DISTRIBUTION - COMPARISON TO LASALLE EVENT DATA

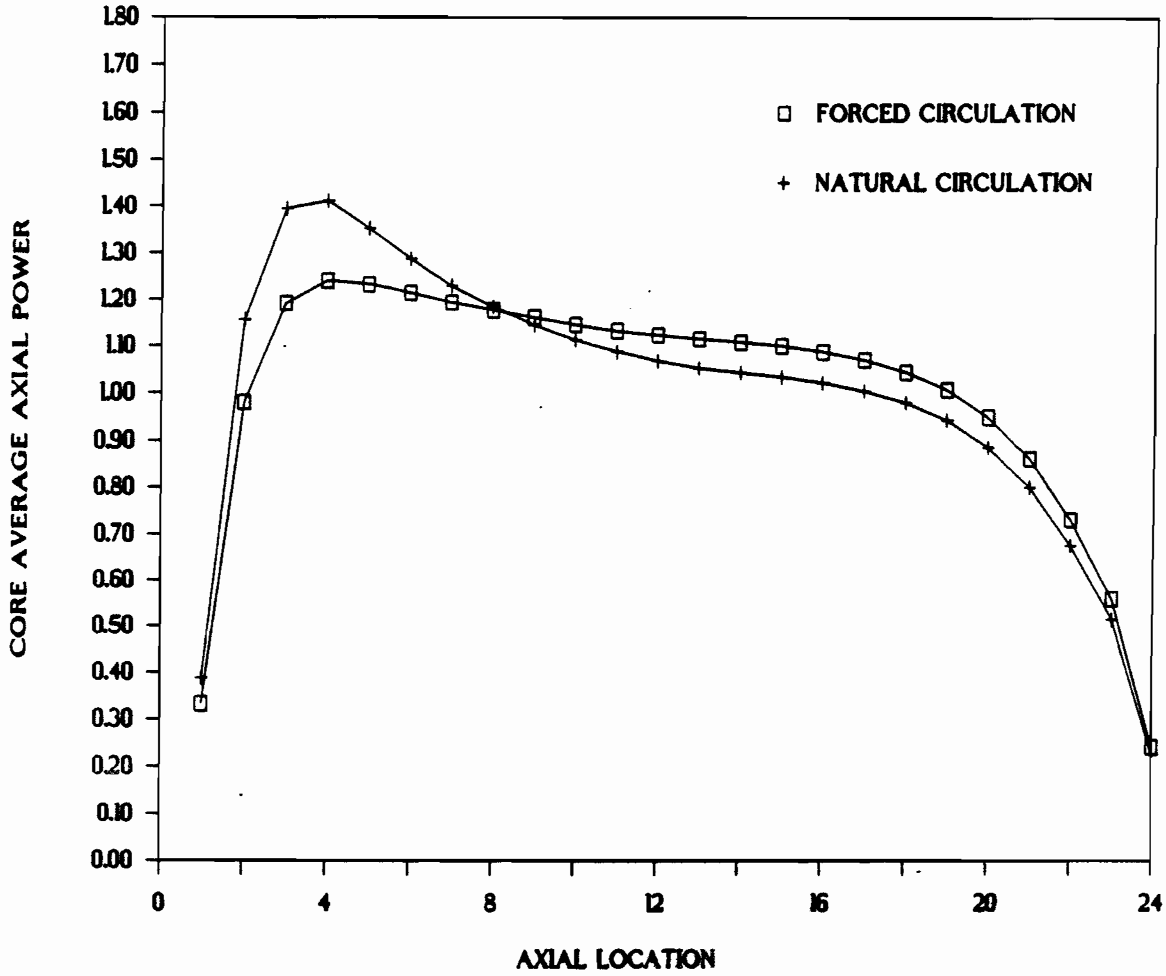

FIGURE 5-13. PERRY CYCLE 2 EOC HALING AXIAL POWER DISTRIBUTIONS

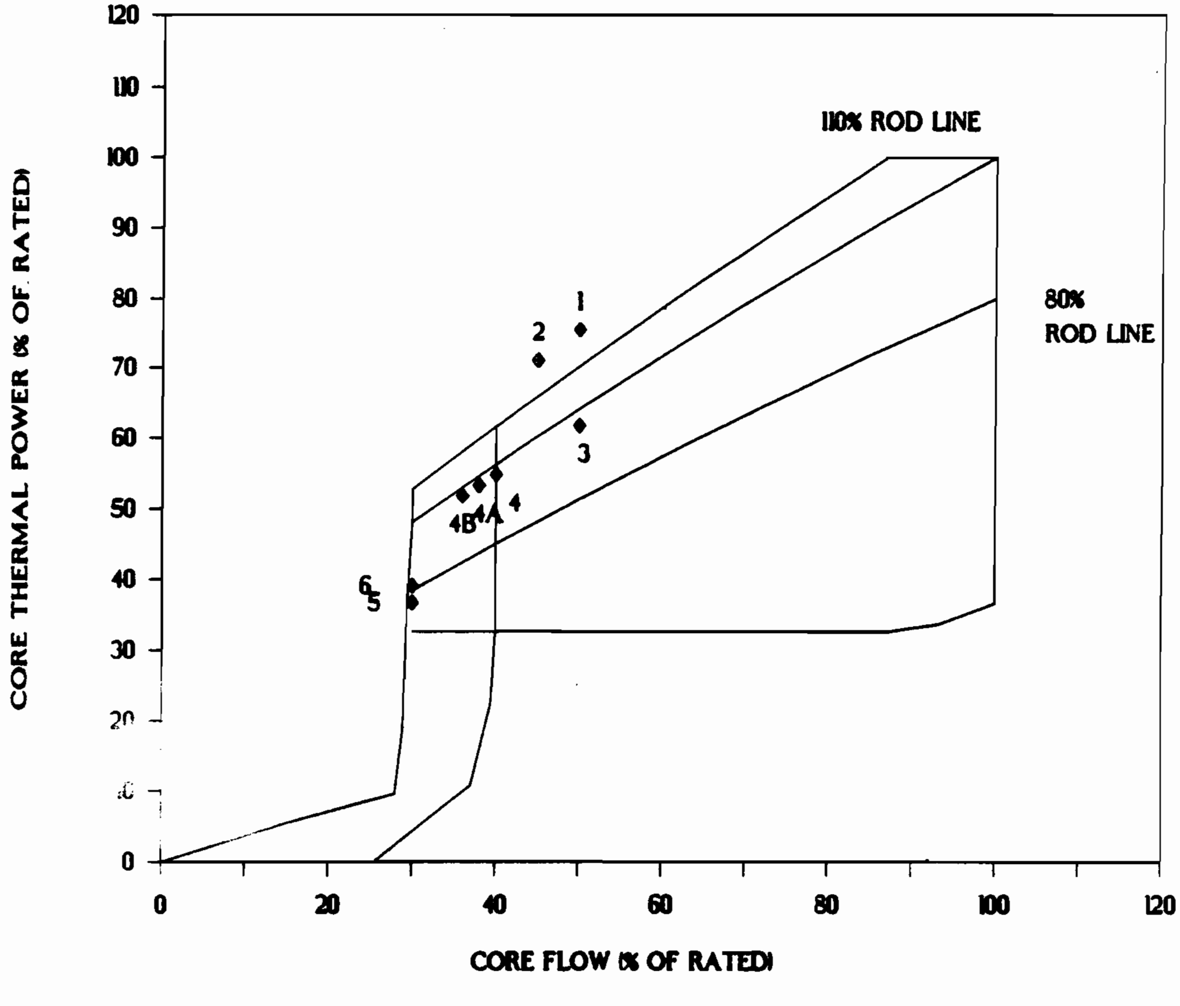

FIGURE 5-14. PERRY CYCLE 2 REGION BOUNDARY DEFINITION ANALYSIS POINTS

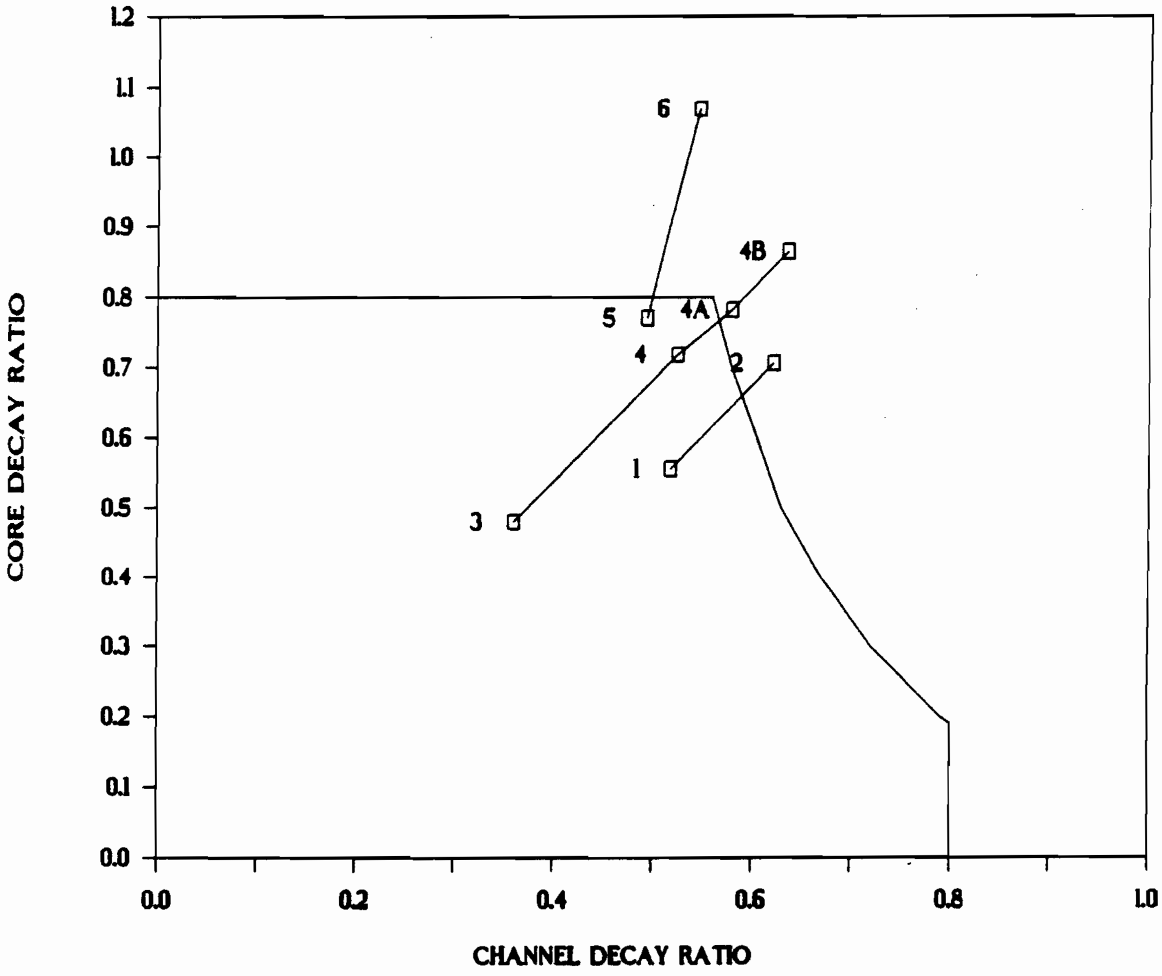

FIGURE 5-15. PERRY CYCLE 2 DECAY RATIOS

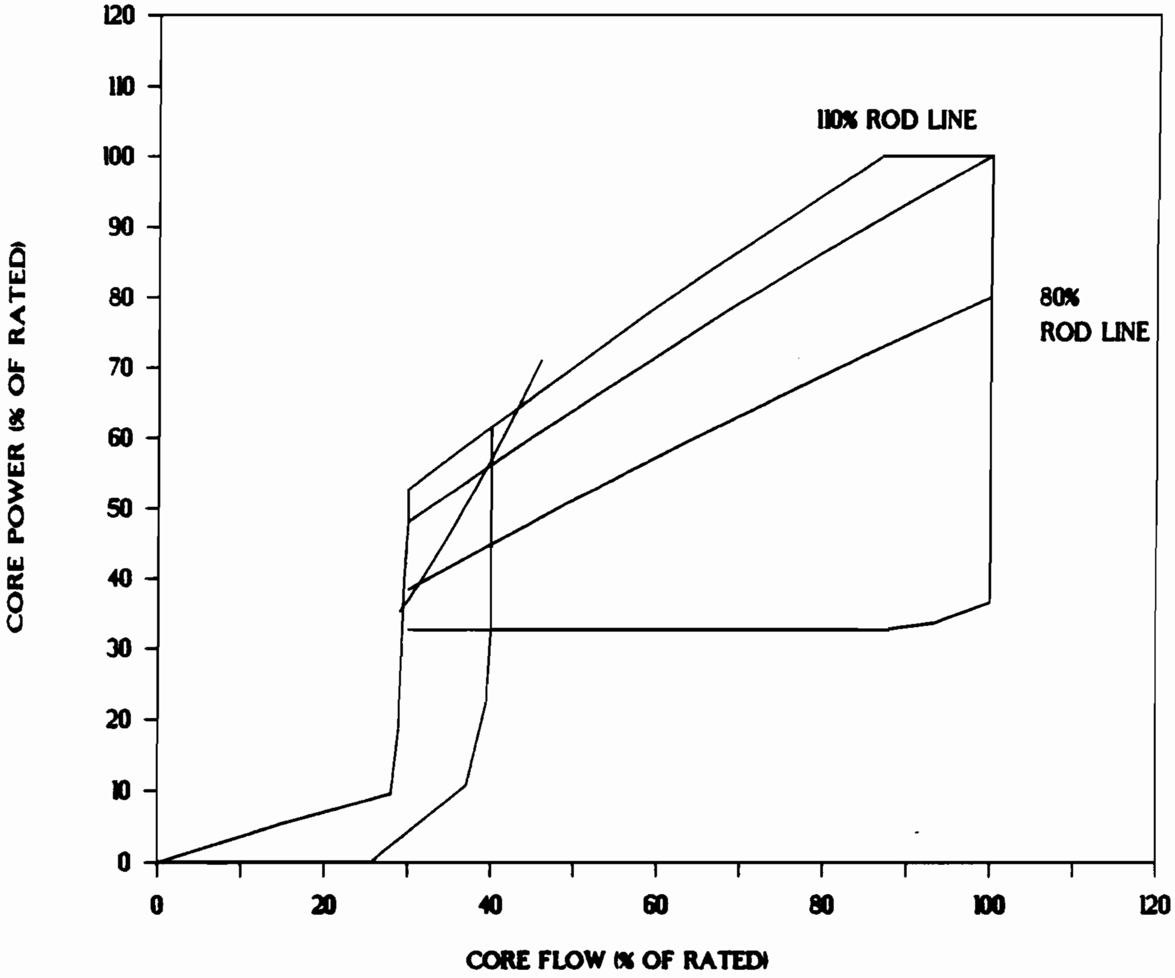

FIGURE 5-16. PERRY CYCLE 2 REGION BOUNDARY DEFINITION

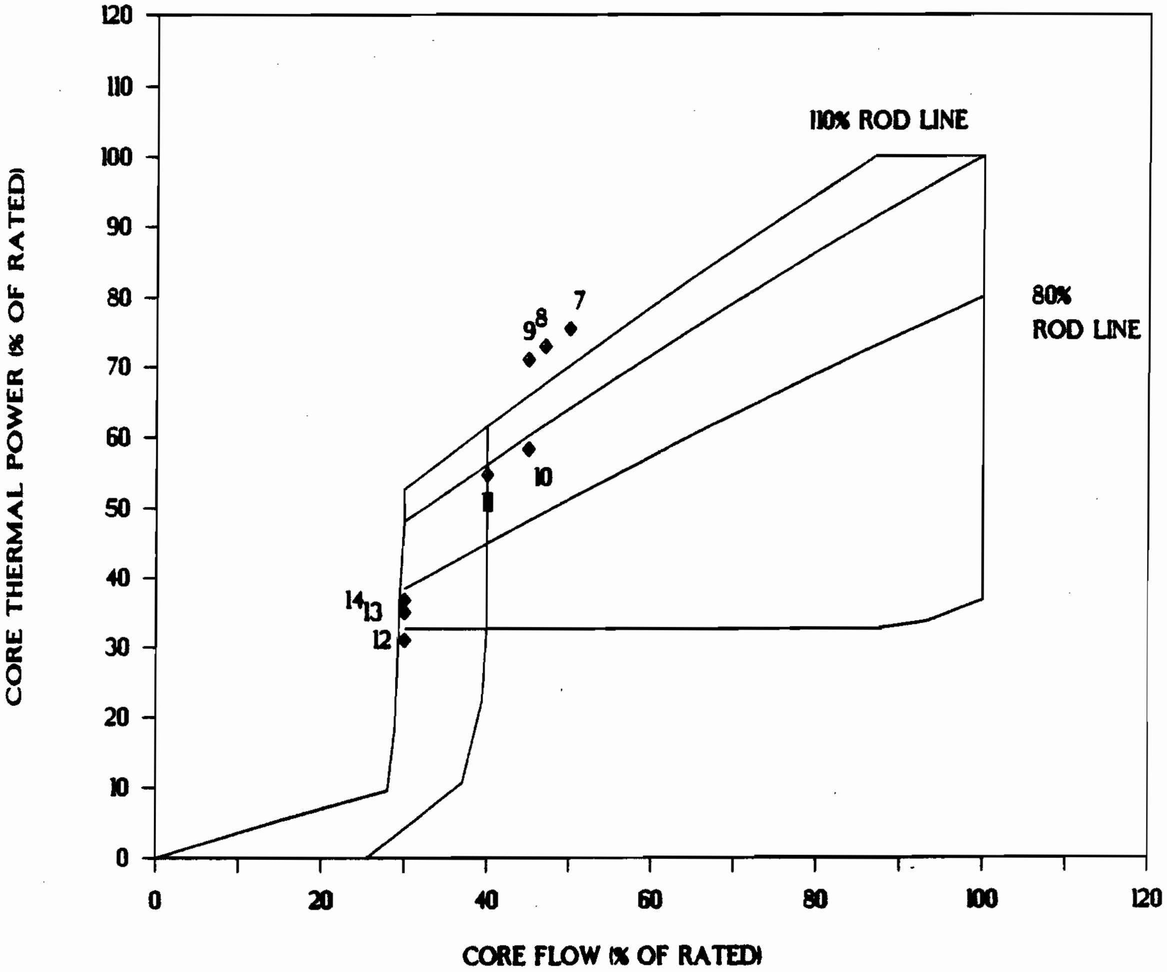

FIGURE 5-17. PERRY EQUILIBRUM CYCLE REGION BOUNDARY DEFINITION ANALYSIS POINTS

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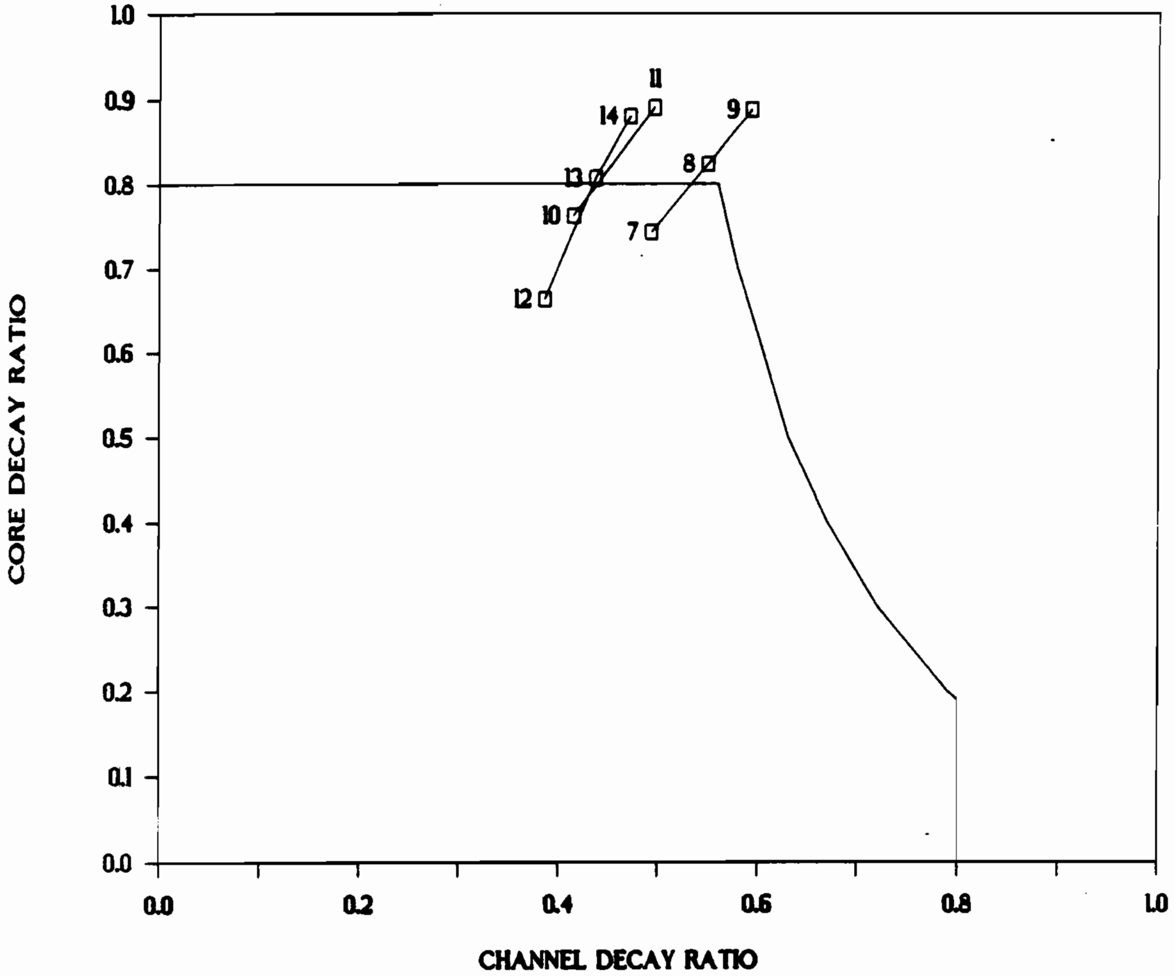

FIGURE 5-18. PERRY EQUILIBRIUM CYCLE DECAY RATIOS

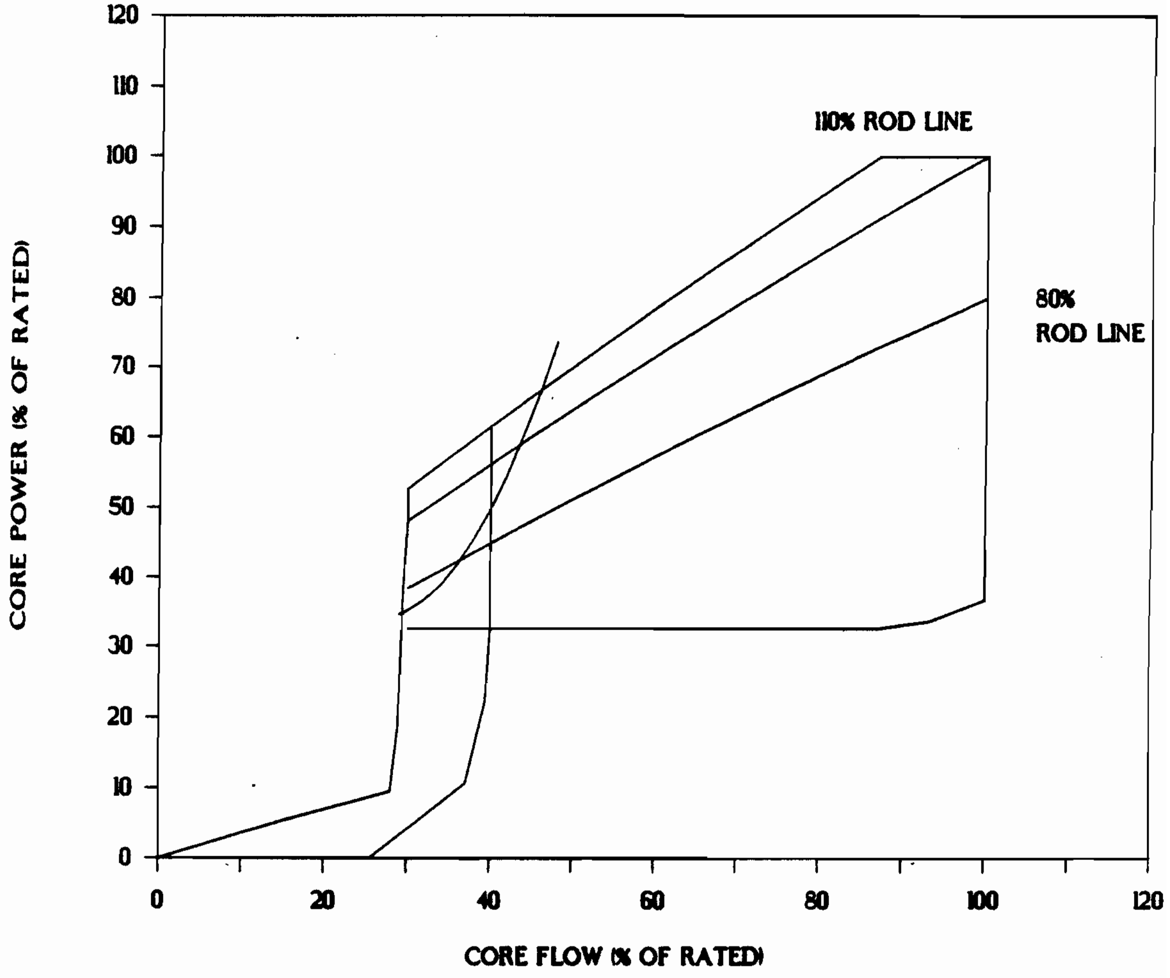

FIGURE 5-19. PERRY EQUILIBRIUM CYCLE REGION BOUNDARY DEFINITION

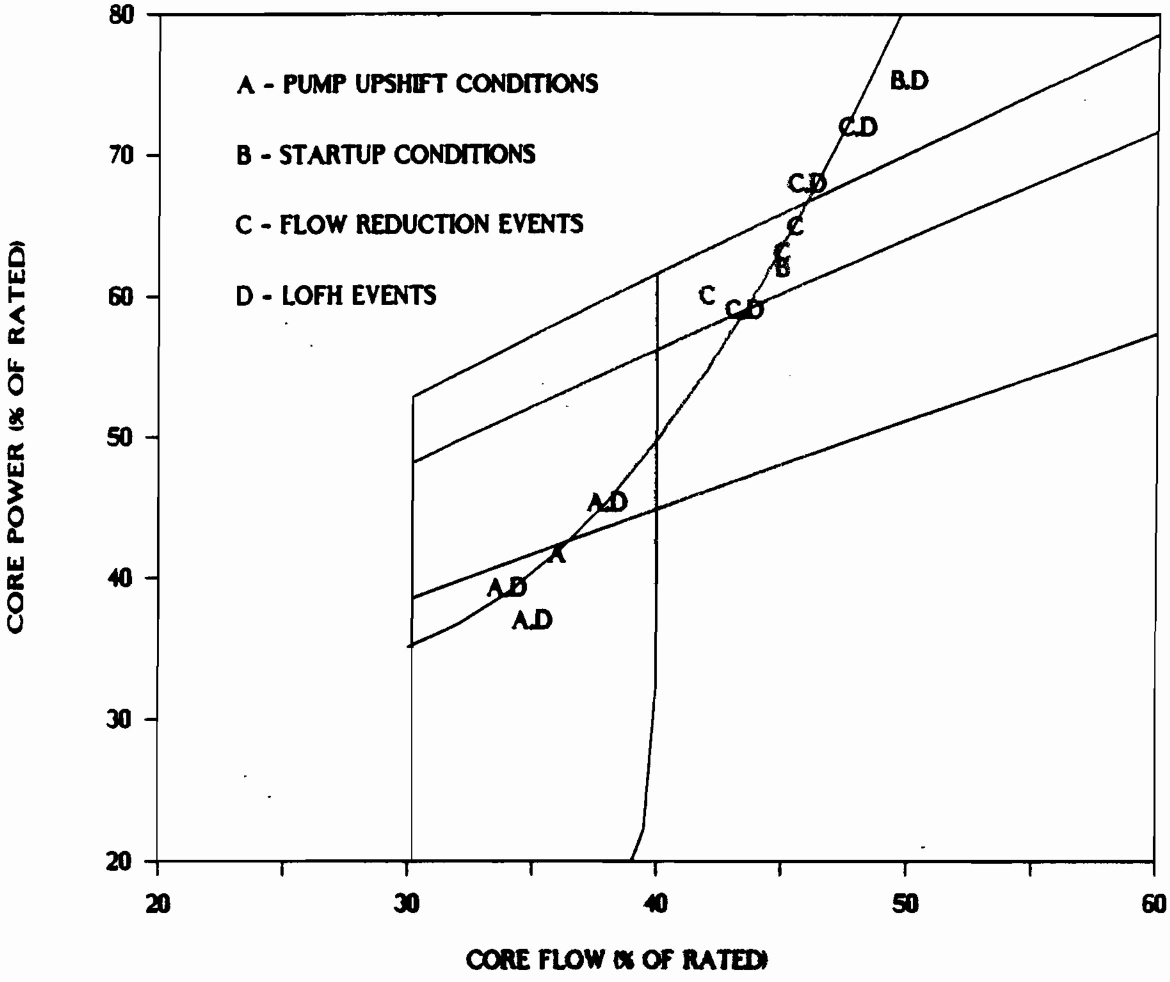

FIGURE 5-20. PERRY EXCLUSION REGION CONFIRMATION ANALYSIS POINTS

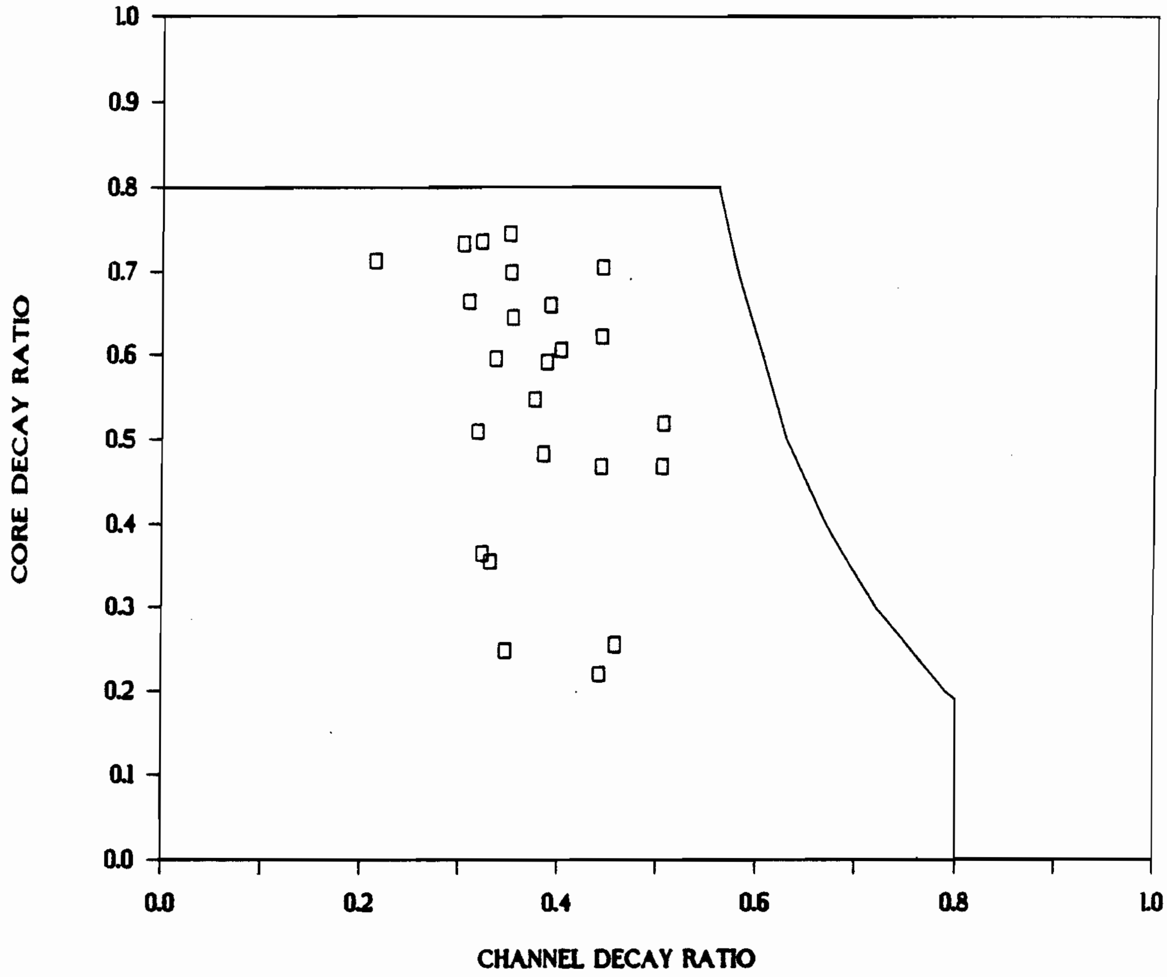

FIGURE 5-21. PERRY CONFIRMATION ANALYSIS DECAY RATIOS

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6.0 DETECTION AND SUPPRESSION LICENSING METHODOLOGY

Detection and suppression systems will be designed to automatically detect and suppress stability-related neutron flux oscillations which could potentially result in conditions exceeding the MCPR Safety Limit. As discussed below, analytical MCPR Safety Limit compliance will be demonstrated for all expected modes of GE BWR thermal-hydraulic neutron flux oscillations.

6.1 EXPECTED OSCILLATION MODES

The licensing basis of detection and suppression systems is to generate a trip signal during oscillations of sufficiently low amplitude to provide margin to the MCPR Safety Limit for all expected modes of BWR oscillations.

The potential oscillation modes are as follows:

- o <u>Core-wide</u> - the average neutron flux in all fuel assemblies oscillates in phase.
- o <u>First Order Side-by-Side</u> - Also called a regional oscillation, where the neutron flux on one side of the reactor oscillates 180° out of phase with the flux on the other side. The axis of zero oscillation magnitude may be at any core azimuth.
- o <u>First Order Precessing</u> - A regional oscillation where the axis of zero oscillation amplitude rotates azimuthally, or the two reactor regions of peak oscillation amplitude shift from one location to another at a frequency lower than the oscillation frequency.
- o <u>Higher Order Modes</u> - Oscillations with more than one line of symmetry, such as a quarter core oscillation, where the neutron flux in one quadrant of the core oscillates out-of-phase with the neutron flux in the two adjacent quadrants, but in phase with the neutron flux in the diagonal quadrant.

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- o <u>Single channel</u> - Thermal-hydraulic oscillations in a single fuel assembly. Characteristic of idealized conditions in which a single fuel assembly operates under an imposed constant plenum-to-plenum pressure drop and constant heat flux.

In GE BWRs, only core-wide and first-order regional oscillations have been observed. In general, these are defined as the expected modes of oscillation for GE BWRs. For one specific class of plants, the expected modes of oscillation are further defined to include only the core-wide mode of oscillation with appropriate justification provided (Appendix A). The following discussion as to why higher order modes of oscillation and single channel oscillations are not expected modes is applicable to all GE BWRs.

6.1.1 <u>Higher Order Oscillation Modes</u>

The existence of regional oscillations in a BWR is the result of the excitation of radial harmonics in the neutron flux. The neutron flux distribution in a BWR is analogous to the solution of a standard wave equation in which a fundamental mode and an infinite number of harmonic modes all satisfy the necessary conditions of the steady-state equations. The primary boundary condition in a BWR is that the neutron flux vanishes near the edges of the core. In the radial plane, this is ideally satisfied by a cosine type shape, symmetric about the center of the core. Higher order cosine functions can also satisfy the edge boundary conditions. However, the geometric buckling associated with these harmonic modes is larger than that of the fundamental mode and results in the harmonic modal eigenvalues being less than that of the fundamental mode. This difference in eigenvalues is commonly referred to as the eigenvalue separation of a harmonic and is a measure of the separation between the fundamental and the harmonic mode.

At steady-state critical conditions, the eigenvalue of the fundamental is equal to 1.0 (critical) and, therefore, all harmonic modes must be subcritical (i.e., eigenvalues < 1.0). Subcritical modes will decay in time and will therefore not be present in general at steady-state conditions. For a subcritical mode to be sustained, sufficient spatial reactivity feedback must be provided to overcome the eigenvalue separation. Thermal-hydraulic oscillations in which changes in channel inlet flows are allowed to oscillate out-of-phase (e.g., inlet flow is increasing in one half of the core while it is decreasing in the other half) are capable of providing this spatial reactivity component to excite the harmonics. Hydraulically, the reactor system tends toward a side-by-side oscillation instead of a core-wide oscillation, since the total core flow is essentially unaffected and the recirculation loop resistance to flow change does not have to be overcome. However, the flow oscillation must have sufficient spatial reactivity feedback to overcome the eigenvalue separation of the harmonics.

The most common regional oscillation that has been observed in BWRs is the first-order side-by-side oscillation. This is the first harmonic in the azimuthal direction for standard cylindrical coordinates. The mode is called first order, since there is only one line of symmetry across which the neutron flux associated with the harmonic mode changes from positive to negative. Higher order harmonics, next being the second-order harmonics (i.e., two lines of symmetry), have even higher eigenvalue separations than most first-order harmonics. An easily recognized second-order harmonic is a quarter core oscillation where the harmonic mode neutron flux is positive or negative in every other quadrant. An example of the eigenvalue separation for several harmonics from a condition that resulted in a north-to-south orientation of a side-by-side regional oscillation is shown in Figure 6-1.

For a higher order mode to be excited in a BWR, sufficient spatial reactivity feedback must be provided to overcome the eigenvalue separation. In general, any spatial reactivity perturbation expected in a BWR that would excite a higher-order mode will also excite the first-order mode in the same spatial coordinate. Since the first-order mode has significantly lower eigenvalue separation, the resulting response will be detected in the first-order mode. If the spatial feedback continues to increase, the higher order modes could theoretically become excited; however, this would be expected to occur well after the detection and suppression system has detected the first- order mode and initiated suppression of the oscillation.

A similar argument also exists for the first-order harmonic in the radial direction, referred to as an inside-outside or "donut" mode. Geometrically, this mode has a much larger eigenvalue separation than the first-order side-by-side modes and is further precluded by operation of BWRs in quarter core and octant symmetric control rod patterns and fuel loading schemes. These last two factors result in a very heterogeneous condition azimuthally, which precludes a pure radial first-order harmonic. In general, the inside-outside mode would only be expected to occur superimposed on a second-order azimuthal harmonic mode. This further increases the eigenvalue separation and reduces the probability of sustaining the harmonic.

Based on the above discussions, it is concluded that the expected modes of oscillation in a BWR are the core-wide (in-phase mode) and the first-order side-by-side and precessing modes (see Appendix A for specific analyses which justify the core-wide mode as the expected mode of oscillation for a specific class of plants). Higher order modes and the first-order radial mode (inside-outside) are not expected to occur because of their large eigenvalue separation and the capability of the detection and suppression system to detect the first-order mode prior to sufficient reactivity feedback to excite the higher order modes. This conclusion is consistent with stability experience to date, even for the large amplitude oscillations observed at several plants.

6.1.2 Single Channel Hydrodynamic Stability

(1) Operating and Analytical Experience

Pure channel hydrodynamic oscillations (instabilities without nuclear feedback) are not an expected mode of BWR oscillations. Early reactor tests, instabilities at the Caorso plant, and several European BWR tests have demonstrated the nuclear coupling of the reactor in response to local reactivity insertion (i.e., control rod withdrawal). At least six regional oscillation tests or events have occurred in European reactors, which also demonstrated the nuclear coupling phenomenon and the fact that individual channel flow responses are driven by the regional core response.

A plot of known GE-BWR instability experiences, including the six European events, is provided in Figure 6-2. The core and channel decay ratios were calculated after the event using the FABLE/BYPSS methodology. As can be seen in this figure, all events with high single channel decay ratios actually resulted in regional or core wide oscillations, and not single channel oscillations for these cores consisting of hydraulically compatible fuel. The single channel event at 0.2 core decay ratio and 1.0 channel decay ratio occurred under extreme conditions at Garigliano where a special test assembly was outfitted with a turbine device at the top of the assembly. The oscillations occurred when the device malfunctioned, creating an unusually large two-phase pressure drop.

A high channel decay ratio requires high bundle power and low core flows, both of which cause the core decay ratio to increase and result in conditions conducive to a regional or core wide oscillation.

Further evidence that single channel oscillation is not an expected oscillation mode was obtained in a TRAC-G analysis of the spatial neutronic response to a postulated single channel oscillation. A fuel assembly was modeled with artificially modified pressure drop components (i.e., it was not hydraulically compatible with the other fuel) such that without neutronic feedback, the assembly was unstable. When the assembly was introduced into the 3-D coupled neutronic thermal-hydraulic TRAC-G model, the neutronic feedback dampened the single channel response such that the channel was stabilized. Further modification of the single assembly pressure drop conditions had to be performed before the assembly would remain unstable in the coupled reactor.

This analysis demonstrates the importance of neutronic coupling and the tendency for the neutronics to prefer the core-wide mode. For a single channel to independently oscillate, significant local reactivity feedback must be present to sustain the oscillation and overcome the eigenvalue separation between the fundamental mode and the single channel oscillation conditions. For the cases analyzed with TRAC-G, it was concluded that unrealistic modifications to the channel's hydraulic characteristics were required to provide this local reactivity feedback. For cores with hydraulically compatible fuel designs, these conditions do not occur.

Additionally, BWR reactor reload design practices and the fact that reactors are typically operated in quarter core or octant symmetry assure that there are at least four to eight bundles with very similar operating conditions. This reinforces the tendency of a regional or core-wide oscillation to develop preferentially to a single channel oscillation.

(2) Single Channel Oscillation Probability and Consequences

If a single channel oscillation should occur, it is unlikely that the MCPR Safety Limit basis of 99.9% of the fuel pins avoiding boiling transition would be exceeded. For this to occur, all of the following must occur:

(a) A low core flow condition is reached where the single channel decay ratio is high, but the core decay ratio is very low. It is extremely unlikely to have a wide disparity in decay ratios and not have a regional oscillation for which automatic suppression occurs.

(b) The oscillation would have to go undetected with no operator actions taken to suppress the oscillations. This is extremely unlikely, because the nearest LPRM will undergo very large oscillations. The conditions needed to put one assembly at much higher peaking than its symmetric counterparts are not likely to occur; if postulated, these conditions would be more likely during control rod withdrawal when the operator routinely has the LPRMs displayed.

(c) The single channel oscillation must grow to a magnitude large enough to reach the MCPR Safety Limit.

(d) The oscillation reaches a magnitude sufficient to put 0.1% of the reactor fuel pins (e.g., 47 pins in a 764 fuel assembly core) in boiling transition. This magnitude depends on the number of pins required to reach 0.1% and the pin-to-pin power distribution of the assembly. At this higher magnitude, detection is even more likely.

(3) Consequences

Even if all of the above occurs, the consequences of such an event are minimal, because the fuel pin will be repeatedly quenched during the oscillations and fuel failure is not expected due to transition boiling. Considering the small probability of a single channel oscillation exceeding the MCPR Safety Limit, and the associated minimal consequences, it is concluded that automatic suppression of a single channel oscillation is not required.

6.2 OSCILLATION METHODOLOGY DESCRIPTION

Detection and suppression systems have a common element in the use of LPRMs for the detection of variations in neutron flux that are indicative of stability-related oscillations. Complex codes such as TRAC-G are capable of simulating the spatial dependence of neutron flux oscillations such that the LPRM response for a given oscillation can be determined. However, analysis using codes such as TRAC-G is very resource intensive and does not allow the evaluation of a wide range of potential oscillation characteristics, since the code will calculate a given response for a specified set of initial conditions. To demonstrate that a detection and suppression system can reliably mitigate oscillations prior to exceeding the MCPR Safety Limit, a methodology is required that will relate the MCPR performance of a limiting bundle with the expected response of LPRMs throughout the core. When this response is combined with a specific trip system configuration, confirmation of that system's setpoints can be performed. A methodology has been developed that enables the simulation of a wide variety of oscillation characteristics.

The oscillation methodology shown in Figure 6-4 has three basic components: (1) the basic oscillation model which describes the time dependent behavior of the oscillations; (2) the GE 3D BWR Simulator, which calculates the fundamental and harmonic power distributions; and (3) the MCPR performance correlation, which relates MCPR to bundle oscillation magnitude.

The oscillation methodology uses a simple model that generates an oscillating signal with a specified frequency, phase lag relative to a reference point, relative oscillation magnitude, and average signal value (Figure 6-3). This basic oscillation model simulates the response of the peak bundle in the core or simulates the response of any of the LPRMs within the core. The GE 3D BWR Simulator is used to predict the spatial dependence of oscillations. This relies on the prediction of the neutron flux distribution in the fundamental and harmonic modes. The fundamental power distribution is used to determine the average steady-state LPRM values throughout the core (A_{ijk}). The harmonic power distribution is used to predict the relative oscillation magnitude ($[(P-M)/A]_{ijk}$) throughout the core, in particular, at LPRM locations. Results from TRAC-G simulations are used to relate the peak bundle oscillation magnitude to a change in CPR during the oscillation. For a given absolute magnitude oscillation in a peak bundle, this methodology is used to determine the resulting LPRM signals as a function of MCPR (Figure 6-4). These three components are discussed in more detail in the following sections.

6.2.1 Basic Oscillation Model

Based on testing and operational data, limit cycle oscillations as measured on the LPRMs resemble sine waves at low magnitude and become increasingly non-linear as the oscillation magnitude increases. This results from the fact that the minimum of the oscillation cannot go below zero and eventually most of the increase in magnitude must be realized above the average. An example of a typical non-linear flux response as measured by an LPRM is shown in Figure 6-5. This non-linear behavior is readily simulated by simplified equations describing the phenomenon (Reference 9) and can be represented by a Fourier series, where the non-linear behavior is characterized by an increase in the magnitude of the signal power at frequencies which are multiples of the fundamental oscillation frequency.

Previous studies of oscillations (Reference 2) have demonstrated the adequacy of using higher order sine waves to model the non-linear behavior of the neutron flux. As the oscillation magnitude becomes large, the non-linear effects are more pronounced and the shape of the oscillations more closely resemble higher order sine waves.

Any oscillation (bundle or LPRM) is represented in the basic oscillation model as,

$$T(t) = f(\{P-M\}/A, A, \omega, \theta) \quad (6\text{-}1)$$

where

T = Oscillating parameter (peak bundle power or LPRM signal)

P = Peak value during oscillations

M = Minimum value during oscillations

A = Average value during oscillations

{P-M}/A = Relative oscillation magnitude

ω = Frequency of oscillation

t = Time (sec)

θ = Phase angle relative to a reference point in the core

A comparison of the basic oscillation model to plant LPRM data is shown in Figure 6-6. This shows the good agreement between the oscillation model and plant data in the range of interest. Equation 6-1 is used to simulate the peak oscillation magnitude for a limiting fuel bundle. The relationship between the peak bundle oscillation magnitude and the LPRM oscillation magnitudes is determined by the GE 3D BWR Simulator as discussed in Section 6.2.2.

Since the LPRMs are distributed radially and axially within the core, their relative phase lag must be known to ensure that combinations of LPRM signals are correctly modeled. The radial component is determined by the expected oscillation mode and is discussed in Section 6.2.2. The axial phase lag is primarily influenced by thermal-hydraulics. General stability theory

(Reference 10) relates the axial phase lag to the speed of the traveling density wave. This speed is associated with the void transit time. The void transit time is directly related to the local void fraction and coolant velocity. These parameters are, in turn, dependent on subcooling and power distribution. The measured phase lags between LPRMs from a single string during testing at several BWRs is shown in Figure 6-7. Since the axial phase lags are the result of complex combinations of conditions, conservatively large axial phase lags are used for the simulation.

6.2.2 Oscillation Contours

Simulation of LPRM signals to confirm detect/suppress system setpoints requires knowledge of the oscillation magnitude throughout the core. The oscillation methodology assumes that the oscillation in neutron flux can be expressed as a function separable in space and time, where

$$\phi(\underline{r},t) = \psi(\underline{r})T(t) \qquad (6\text{-}2)$$

= Neutron flux at location $\underline{r}$

$\psi(\underline{r})$ = Spatial shape function

$T(t)$ = Amplitude function

The amplitude function is an oscillatory component that only describes the normalized time dependent behavior of the oscillation (Equation 6-1). The shape function, or "oscillation contour," describes the distribution of oscillations throughout the core. This representation of the oscillation is analogous to the derivation of point kinetics models, which assumes that the basic power distribution remains constant during a transient. For the oscillation model, the oscillation distribution is assumed to remain constant.

A core-wide (in-phase) oscillation is an excitation of the fundamental mode in the radial/azimuthal plane and its "oscillation contour" is constant and equal to the core average relative oscillation magnitude. The "oscillation contour" is defined as the relative distribution of oscillation magnitudes within the core and is expressed in terms of each LPRM's (P-M)/A oscillation magnitude. For regional (out-of-phase) oscillations, a harmonic mode is excited in the radial/azimuthal plane and results in a distribution of oscillation magnitudes radially across the core.

One source of oscillation contours for regional oscillations is from plant data obtained during oscillations. The oscillation contour for the Caorso Cycle 2 test condition (Reference 11) is shown in Figure 6-8, where the z-axis represents the oscillation magnitude for a given LPRM string, expressed as (P-M)/A. The general shape of the oscillation contour is similar to the neutron flux distribution of the first harmonic of the neutron diffusion equations. The data suggest that the relative oscillation magnitude (i..e, shape function) is characterized by the harmonic flux distribution. Modal synthesis methods (Reference 12) are commonly used to describe the neutron flux during spatial transients. These methods assume that the transient neutron flux can be expressed as a function of the steady-state modal flux distributions and associated amplitude functions. For regional oscillations, the fundamental and first harmonic mode neutron flux distributions in the radial plane are sufficient to describe the spatial behavior of the oscillations.

To evaluate the validity of this assumption, the GE 3D BWR Simulator code (Reference 8) was modified to calculate the harmonic mode of the neutron flux (Reference 13). The method has been validated by solving a benchmark problem consisting of a homogeneous rectangular parallelepiped reactor. The analytical solution to this problem is known and is accurately calculated by the modified GE 3D BWR Simulator (Table 6-1).

To calculate the radial harmonic modes with the GE 3D BWR Simulator, a standard calculation of the fundamental power distribution is performed for a specified set of initial conditions (core and fuel design, power, flow, control rod pattern, etc.). Using the modified version of the code, the power distribution in a number of harmonic modes is then calculated. The GE 3D BWR Simulator explicitly determines the potential harmonic modes based solely on the constraints of the neutronics. These are assumed to be the potential oscillation modes for the given initial conditions. Although these modes would not necessarily be sustained for the actual conditions of the plant when thermal-hydraulic feedback is included, the calculations represent the possible oscillation modes should an instability occur. In general, only two oscillation modes are calculated, both of which are first order regional oscillations. Higher order modes can be calculated by the Simulator but are not expected modes because of the very high eigenvalue separation (see Section 6.1). For quarter core symmetric core loadings and control rod patterns, the two first-order radial modes calculated are orthogonal modes in which the oscillation axes of symmetry calculated by the Simulator are perpendicular for the two modes (e.g., if one mode has an axis that runs north-to-south, the second mode's axis runs east-to-west). For each of the radial harmonic modes, the oscillation contour (i.e., shape function) is calculated as follows:

$$\psi^n_{ij} = P^n_{ij}/P^n_{max} \qquad (6\text{-}3)$$

= Normalized azimuthal oscillation contour at location i,j (normalized to maximum relative bundle power)

P^n_{ij} = Relative bundle power at location i,j for harmonic n (normalized to an average value of 1.0)

P^n_{max} = Maximum relative bundle power for harmonic n

The above expression is calculated for each bundle in one half of the core relative to the oscillation axis of symmetry. Oscillation contour values for bundles in the other half of the core are equal to the value for their symmetric bundle. For bundles in the other half of the core, a radial phase lag of 180° is also needed. The contour has been specifically normalized to the oscillation magnitude of the peak bundle, since this is the limiting oscillation in the core. The methodology is centered around first specifying the oscillation magnitude for the peak bundle, and then determining the response of the LPRMs relative to the peak bundle. An individual LPRM detector reading is assumed to be proportional to the response of the surrounding eight fuel nodes (two axial nodes from each of the surrounding four fuel bundles at the appropriate elevation). An example of an oscillation contour is shown in Figure 6-9, where the values represent the oscillation magnitude for a specific LPRM relative to the oscillation magnitude for the peak bundle. For example, the LPRM at 16-09 is calculated to oscillate at 85% of the oscillation magnitude of the peak bundle.

As discussed above, this shape function is assumed to represent the oscillation magnitude at any radial location within the core. Because the harmonic flux distribution is relative to the fundamental distribution (i.e., the harmonic flux distribution describes the change in neutron flux relative to the fundamental or steady state flux distribution), it is assumed to be a representation of the (P-M)/A oscillation magnitude distribution. Using this calculation of the oscillation contour, the method has been compared to stability data taken at an operating BWR. Comparison of the (P-M)/A for LPRM readings during a regional oscillation with a contour plot of the first harmonic of the neutron flux from the GE 3D BWR simulator shows good agreement (Figure 6-10).

Once the normalized azimuthal oscillation contour, ψ^n_{ij}, is determined, the oscillation magnitude expressed as (P-M)/A at any location (i,j) can be determined by first choosing a value for the peak oscillation magnitude. At each location (i,j), the oscillation magnitude is then determined as

$$((P-M)/A)_{ij} = \psi^n_{ij} * ((P-M)/A)_{max} \qquad (6\text{-}4)$$

This model conservatively assumes the oscillation magnitude is constant axially within a bundle or LPRM string. Therefore,

$$(P-M)/A)_{ijk} = ((P-M)/A)_{ij}. \qquad (6\text{-}5)$$

6.2.3 MCPR Performance

The previous sections have identified the methodology for describing the spatial and temporal dependence of oscillations for the peak bundle and for each LPRM in the core. Since the purpose of the methodology is to confirm that a specific trip system protects the MCPR Safety Limit, the final piece of the methodology is to determine the change in CPR during a specified oscillation. Fully-coupled TRAC-G calculations of core-wide and regional oscillations are performed for a variety of plant and fuel types at various conditions. Each of these cases generates a certain oscillation magnitude and resultant CPR change in the limiting bundle. A correlation is then developed relating the CPR change to the peak bundle oscillation magnitude relative to the average bundle power. Based on existing TRAC-G evaluations, correlations have been developed for the relative change in CPR during oscillations as a function of the relative oscillation magnitude. Example correlations for the response during regional oscillations are shown in Figure 6-11. The correlations represent the different responses for relatively high channel decay ratios and for more nominal channel decay ratios.

6.2.4 Example Application of Oscillation Methodology

The oscillation methodology used to calculate MCPR response relative to LPRM oscillation magnitudes is summarized in Figure 6-4. To demonstrate the use of the methodology, an example calculation is performed for a 560 bundle BWR/4 plant. The initial conditions prior to the oscillation are natural circulation near the rated rod line, at end of cycle conditions with all control rods withdrawn. These conditions are analyzed using the GE 3D BWR Simulator to calculate the initial LPRM distribution, initial radial peaking factor and MCPR for the hot bundle. The initial conditions are summarized in Table 6-2. The Simulator is also used to calculate the oscillation contour. The first harmonic is calculated to be a regional oscillation with an oscillation axis of symmetry along the northwest-southeast diagonal and the contour is shown in Figure 6-12. The oscillation period is assumed to be 2.0 seconds and the axial phase lags are based on measured data from plant stability tests. The peak bundle oscillation magnitude ((P-M)/A) is assumed to be 1.0, which represents an oscillation magnitude of 100% of the average steady-state value. The oscillation characteristics are also summarized in Table 6-2.

The basic oscillation model is then used to predict the response of the LPRMs and the peak bundle. The LPRMs are also combined to form their respective APRM channels and are combined to form OPRM cells consisting of eight LPRMs each (Appendix A). The results of the simulation are summarized in Table 6-3.

The calculated behavior of the peak bundle power is shown in Figure 6-13. LPRM responses for different locations within the core, as well as for different axial locations within a single LPRM string, are shown in Figures

6-14 and 6-15. The axial and radial phase lags can be seen in the figures. Representative APRM channel responses are shown in Figure 6-16 and several OPRM channel responses are shown in Figure 6-17.

6.3 APPLICATION OF OSCILLATION METHODOLOGY

To confirm that a specific detection and suppression system adequately protects the MCPR Safety Limit, analyses must be performed that cover a representative range of potential initial conditions and oscillation characteristics. In addition, the uncertainties in the modeling and inputs must be considered in the confirmation calculations. The basic oscillation methodology which calculates the MCPR performance as a function of LPRM response for a specific set of initial conditions is described in Section 6.2. To provide the best representation of expected oscillation responses, the most sensitive inputs to the methodology are randomly chosen from distributions which describe the expected variation of the parameters. These randomly selected inputs (Section 6.3.2) are then evaluated using the oscillation methodology to produce a specific MCPR for a given case.

A large number of cases is evaluated and the 95% probability/95% confidence level MCPR ($MCPR_{95/95}$) is determined. The 95% probability/95% confidence level acceptance criterion assures that a measurable and adequate level of conservatism is included. The $MCPR_{95/95}$ value is then compared to the MCPR Safety Limit to confirm that the specific combination of inputs is acceptable.

6.3.1 Design Objective

Standard reload licensing analyses typically calculate the change in CPR for a set of transients to determine the most limiting event. The CPR change during the limiting transient is then added to the MCPR Safety Limit to establish the MCPR operating limit. This technique is established to ensure that, if the limiting transient were to occur when the plant was operating at the MCPR operating limit, the MCPR Safety Limit would not be exceeded. The design objective for detection and suppression systems is to provide mitigation such that an instability does not have to be considered in the evaluation of limiting events. This design objective is satisfied by performing analyses which assume that the plant is at the MCPR operating limit established by the standard licensing analysis, and then confirming, with a high degree of confidence, that the final MCPR during the defined instability has a margin to the MCPR Safety Limit of 0.10. The high degree of confidence is provided by the use of Monte Carlo statistical methods which simulate the various uncertainties associated with calculating MCPR as a function of a trip system's response. Use of the MCPR Safety Limit is also widely recognized as a conservative measure of fuel cladding integrity since damage is not likely during brief periods of departure from nucleate boiling followed by the quenching that occurs during density wave oscillations.

In addition to the explicit treatment of known uncertainties by the Monte Carlo analysis, additional conservatisms exist in the methodology. These conservative assumptions include, but are not limited to, the assumption that (1) every two recirculation pump trip event results in an instability, (2) the instability grows at a rate too fast for the operator to take manual actions, (3) the reactor is at MCPR operating limits just prior to the initiating event, and (4) the most responsive RPS channel is failed at the time of the instability event.

The statistical treatment of known uncertainties and the additional conservative assumptions provide flexibility for the initial design and development of detection and suppression systems. Without this margin, future modifications to CPR correlations, fuel designs, trip system features and other factors affecting stability could potentially result in unacceptable restrictions on plant operation or unnecessary reactor trips caused by overly restrictive setpoints.

6.3.2 Analysis Procedure

The objective of the analysis procedure is to determine the final MCPR during an oscillation event given expected probability distributions of input parameters. The inputs describe the initial reactor conditions before the oscillations, the oscillation characteristics, the trip system design features and the bundle MCPR performance during the oscillations. Figure 6-18 shows a flowchart of the analysis procedure. The initial conditions determine the initial MCPR prior to oscillations. The important oscillation characteristics are the oscillation contour and the rate at which the oscillation magnitude is growing. The trip system design features describe how the LPRMs are combined and evaluated relative to a trip algorithm and setpoints. The trip algorithm, setpoints, and oscillation growth rate determine the maximum amplitude of the oscillations before the ASF suppresses the oscillation. The following sections discuss the different input assumptions and how they are represented in the analysis.

6.3.2.1 Initial Conditions

The initial reactor operating conditions are important in determining the conditions just prior to the onset of oscillations. This is the primary factor in determining the initial MCPR at the onset of oscillations. The initial conditions are separated into two categories: (1) steady-state operating conditions and (2) an initiating event that is assumed to result in the reactor operating at potentially unstable conditions. The potential initial conditions are limited to those that are expected to result in an instability. Oscillations are most likely to occur in the low flow/high power region of the operating domain. This region can be entered as the result of core flow reduction or power increase. In general, power increases are not performed in the region of potential instability. Possible power increases near this region due to control rod withdrawal or feedwater heating loss are relatively slow increases during which the probability of operator intervention, should the onset of oscillations be detected, is very high.

Core flow reductions (e.g., two recirculation pump trips), however, have the potential to result in very large changes in operating conditions in a relatively short time and the operator has less opportunity to intervene during the transient plant conditions. Because of the large change in operating conditions, it is also possible that operation could occur beyond the point of oscillation inception. This is more likely to lead to oscillations that grow to magnitudes which require mitigation when compared to a gradual approach to the instability such as would be experienced during a power increase. The limiting flow reduction event is therefore the two recirculation pump trip event, which results in operation at natural circulation flow. A two recirculation pump trip (RPT) is assumed to be the initiating event for the analysis procedure.

The initial power level prior to the RPT is also an important factor in determining the probability of oscillations and the MCPR prior to the onset of oscillations. In general, operation at higher rod lines results in less stable conditions following an RPT. Therefore, the initiating event is assumed to start from the highest licensed rod line for a particular plant. For a specific initial power and flow condition along the maximum allowed rod line, the plant Technical Specifications require the MCPR to be greater than the MCPR Operating Limit. For the oscillation analysis, it is conservatively assumed that the plant is operating at the MCPR Operating Limit.

Since the majority of the operating cycle is spent at full power operation, the analysis procedure assumes that 95% of the cases begin at full power conditions. The remaining cases are assumed to start from conditions that are representative of startup conditions. During a typical plant startup, control rods are withdrawn along a minimum core flow line (approximately 40% of rated core flow) until the full power control rod pattern is attained, the maximum allowed rod line is reached, or thermal limits are reached. These startup cases also assume an RPT, since the potential for an instability following an RPT is the greatest. For these conditions, the appropriate MCPR Operating Limit at the power/flow conditions specified is assumed.

During the evolution of the RPT, the MCPR increases as core flow decreases to natural circulation conditions. Figure 6-19 shows the MCPR just prior to an RPT and after equilibrium conditions have been reached following the flow reduction. The data points represent the MCPRs calculated by the plant online process computer for various flow reduction events performed during startup test programs at a number of BWRs. The flow reduction events include the trip of both recirculation pumps, recirculation pump runbacks, and single recirculation pump trip events. From the figure, it can be seen that the slopes of the curves which represent the MCPR increase during the flow reduction is relatively constant. This is expected, since the major parameter which determines the final MCPR following the flow reduction is the final power. The final power is dependent on the void reactivity coefficient, axial power distribution, and change in core flow during the flow reduction. Because these parameters will vary during a cycle and from plant to plant, a variation in the final power level at a given core flow along a particular rod line is expected. This variation is described by a distribution of a parameter that represents the change in CPR during the flow reduction. Based on the plant data, the following parameter is defined:

$$\mathrm{DIDW} = \frac{(\mathrm{MCPR}_2 - \mathrm{MCPR}_1)/\mathrm{MCPR}_1}{(W_1 - W_2)}, \tag{6-6}$$

where,

MCPR_1 = Initial MCPR prior to RPT
MCPR_2 = Equilibrium MCPR following RPT
W_1 = Initial core flow (% of rated)
W_2 = Final core flow (% of rated).

Since only limited data exist from plant flow reduction events, the GE 3D BWR Simulator is used to generate a representative set of data for the parameter DIDW. Analyses are performed for a wide variety of plant and fuel types, power distributions and initial power/flow conditions. To verify that the GE 3D BWR Simulator provides an accurate prediction of MCPR along the flow control lines, a comparison with startup test data was performed. The results for two flow reduction events are shown in Figure 6-20, which demonstrate the good agreement between the GE 3D BWR Simulator and the process computer calculations during actual plant tests. An appropriate distribution is generated from the results of the Simulator calculations and, for each case, a random sample is chosen to represent the change in MCPR during the flow reduction portion of the analysis. When combined with the randomly selected initial power/flow condition (full power or startup conditions) and the flow reduction to natural circulation, the initial MCPR prior to the assumed onset of oscillations is determined. The initial MCPR is calculated as:

$$\mathrm{IMCPR} = \mathrm{TSMCPR} * (1.0 + \mathrm{DIDW} * (W_1 - W_2)), \tag{6-7}$$

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where,

IMCPR = Initial MCPR prior to the onset of oscillations at equilibrium conditions reached following the RPT

TSMCPR = MCPR Operating Limit at power/flow conditions prior to the RPT

DIDW = Relative change in CPR during the flow coastdown (equation 6-6)

W_1 = Initial core flow (% of rated)

W_2 = Final core flow, assumed to be natural circulation (% of rated).

In addition to the IMCPR, the radial peaking factor must be determined since the calculation of the peak bundle oscillation magnitude is dependent on the initial bundle power. The radial peaking factor is primarily dependent on the control rod pattern and fuel loading and therefore is expected to vary with cycle exposure and core and fuel design. The GE 3D BWR Simulator is used to calculate the radial peaking factor for a wide range of core and fuel designs and control rod patterns. These results are used to generate a distribution of radial peaking factors from which random samples are taken for each specific case.

6.3.2.2 Oscillation Characteristics

(1) Oscillation Contours

The previous section discussed the initial conditions and initiating event that result in conditions just prior to the assumed onset of oscillations. It is conservatively assumed that every RPT from the maximum allowed rod line results in an oscillation that eventually grows to a magnitude sufficient to exceed the trip system setpoints without any operator intervention. For the majority of plants, the expected modes of oscillation have been defined as the core-wide oscillation mode and the first-order harmonic mode. For core-wide oscillations, all fuel nodes at the same axial location oscillate in phase, resulting in the maximum LPRM, OPRM cell, and APRM responses for a given peak bundle oscillation magnitude. As discussed in Section 6.2.2, the oscillation contour for core-wide oscillations is constant in the x-y plane everywhere in the core and is equal to the magnitude of the peak bundle oscillation. For the regional oscillations (first-order harmonic mode), the oscillation contour is calculated by the GE 3D BWR Simulator, and varies across the core as a function of the distance from the oscillation line of symmetry. Although the expected oscillation modes for an individual plant would include both the core-wide and regional oscillation modes, regional oscillations will be conservatively assumed as the only oscillation mode.

To evaluate the impact of different plant conditions on the oscillation contour, oscillation contour calculations were performed for a variety of plant sizes, operating cycles, control rod patterns, cycle exposure, and Xenon concentrations. The conditions that have been analyzed are summarized in Table 6-4. In general, the oscillation contours are relatively insensitive to most parameters and are determined mainly by geometry. To a lesser extent, the radial power distribution affects the oscillation contour. This is mainly seen in areas near inserted control rods and near the core periphery. Control rod pattern symmetry and fuel loading symmetry play the dominant role in determining the axis of symmetry for the first order azimuthal harmonics.

A portion of the oscillation contour for six different 560 bundle core conditions is shown in Figure 6-21. Each of the oscillations has a NWSE axis of oscillation symmetry. The oscillation contours in Figure 6-21 are based on LPRMs that lie on a diagonal that is perpendicular to the axis of oscillation symmetry (i.e., the NESW diagonal). These LPRMs are therefore at an azimuthal angle of 90° relative to the oscillation axis of symmetry, which represents the maximum oscillation magnitudes for a given radius from the core center. The contours in Figure 6-21 show the same characteristic shape as observed from plant instability data, with some variation from case to case. Of particular interest is the relative oscillation magnitude, for the LPRMs located near the point of peak oscillation magnitude, since these LPRMs provide the maximum signal response. At these locations, the contours do not show a significant scatter. This trend is also true for other core sizes.

Because of the different number of LPRMs for different core sizes, the response of trip systems may vary as a function of core size and number of LPRMs. Therefore, the final setpoint analyses will be performed for each specific LPRM configuration. Because of the relative consistency among the contours, the resulting LPRM response as a function of peak bundle oscillation magnitude is not expected to vary significantly for different contours. Therefore, only a limited number of contours need to be generated for a given core size.

A more important feature of the oscillation contour is the axis of oscillation symmetry. Because of the LPRM symmetry within the core, the trip system responses vary as a function of the oscillation axis of symmetry. For most plants, the NESW and NWSE axes of symmetry are the dominant axes because the plants are only operated in an A2 sequence (i.e., control cell core operating strategy), which typically results in octant symmetric control rod patterns. For plants that operate with conventional cores, operation in the B sequence can result in power distributions that are not symmetric about the diagonals and therefore result in EW and NS axes of symmetry. Therefore, these cores can oscillate about one of the four possible oscillation contour axes. Evaluations have been performed of the system responses as a function of the oscillation axis of symmetry and it has been found that the NESW and NWSE axes of symmetry result in the limiting (i.e., lowest) system responses. Therefore, only these modes of oscillation are assumed in the analysis. This is a conservative assumption for plants that operate with conventional cores (i.e., A and B sequences).

(2) Oscillation Growth Rate

Following the RPT, it is assumed that oscillations begin to grow and eventually reach a limit cycle oscillation. During the time when the oscillation magnitude is growing, the specific trip system will detect the oscillations and initiate an ASF, thereby mitigating the effects of the oscillation. The oscillation model described in Section 6.2 evaluates only one cycle of the oscillation. This cycle is the limiting cycle that results in the peak oscillation magnitude. When the trip system signal exceeds the trip setpoint, the oscillation continues to grow until control rod motion from the ASF begins to mitigate the oscillation.

This effect is illustrated in Figure 6-22 for a growing oscillation that exceeds an absolute magnitude trip setpoint. If the timing of the ASF is such that the oscillation is mitigated before the next cycle begins, the peak oscillation magnitude is represented by the oscillation peak during the cycle that exceeded the trip setpoint ("First Peak" as labeled in Figure 6-22). If the initiation and mitigative action of the ASF is slow relative to the oscillation frequency, it is possible that the "second peak" (as labeled in Figure 6-22) represents the peak oscillation magnitude. These peak oscillation magnitudes are called the signal overshoot, since they represent the amount that the monitored signal overshoots the trip setpoint. Since the oscillation model is based on specifying the peak bundle oscillation magnitude and then calculating the resultant trip system response, the signal overshoot is added to the peak bundle oscillation magnitude prior to determination of the MCPR response. The amount of overshoot is dependent on the growth rate of the oscillation, the amount of inherent noise superimposed on the trip system signal, and the trip system algorithm and setpoint design.

A review of plant stability data shows a range of oscillation growth rates from 1.0 to 1.3. The plant data also show the presence of background noise levels that are always present in BWRs during power operation. Noise components that affect the oscillation response are those with a frequency similar to the fundamental oscillation frequency.

Electronic noise that is always present in the Neutron Monitoring System (NMS) does not significantly affect the trip system responses, since the frequency is much higher than the oscillation frequency and will in general, be filtered out by the detection and suppression systems. An example of measured plant LPRM data during an oscillation with increasing

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magnitude is shown in Figure 6-23 which also shows a simulated oscillation with no background noise component. The oscillation with no background noise shows an exponentially increasing envelope that can be characterized by a constant growth rate during most of the increase. The plant data show the same general trend but with an additional noise component superimposed on the basic growing oscillation. This noise component results in a widely varying growth rate when successive oscillation peaks are evaluated and affects the calculated overshoot.

A point kinetics model which includes simplified equations representing the void and Doppler reactivity feedback components (Reference 9) is used to generate a range of oscillation growth rates. Background noise is simulated by introducing a random noise source to the fuel temperature term in the model. This random noise source results in the characteristic neutron flux noise behavior experienced at operating BWRs. An example of a simulation for reactor conditions which correspond to a decay ratio of 0.48 (stable) is shown in Figure 6-24. The steady-state noise levels that are characteristic of BWRs are well represented by the point model. Examples of oscillations generated by the point model are shown in Figures 6-25 and 6-26. These oscillations represent growth rates of approximately 1.05 and 1.30, respectively. These oscillation "scenarios" are used to determine the expected trip signal overshoot for a specific trip system algorithm design and setpoints (Section 6.3.2.3). Scenarios have been generated with growth rates ranging from 1.05 to 1.60, with the majority of the growth rates near 1.30. A growth rate of 1.30 was chosen as the dominant growth rate, since this bounds available plant stability data.

For the analysis procedure, the generated scenarios are evaluated against a specific trip system algorithm and corresponding setpoints to determine the distribution of the signal overshoot. An example distribution of setpoint overshoot for the OPRM system described in Appendix A is shown in Figure 6-27. The overshoot distribution corresponds to the distribution of "second peaks" as defined in Figure 6-22. The "second peak" is conservatively chosen for BWR/3-5 plants, since the Technical Specification scram times are of the same magnitude as the expected oscillation frequency (2.0 seconds to 50% insertion). For BWR/6 plants, the Technical Specification scram times are shorter than the expected oscillation period and, therefore, the ASF mitigates the oscillation prior to the second peak. The first peak is used to represent the overshoot distribution for BWR/6 plants.

For the OPRM system, the trip system signal and setpoints are expressed in terms of the signal value relative to a time-averaged value. For the evaluation of a specific case, a randomly selected overshoot is chosen from the specified distribution. This represents the maximum value that the trip system signal reaches during the oscillation. Based on this input, the peak bundle oscillation magnitude that results in this signal magnitude is then determined. A nearly identical procedure is used to generate the overshoot distribution for evaluating the APRM response for Options I-C and I-D, and the LPRM response for Option III-A.

6.3.2.3 Trip System Definition

Once the initial conditions, initiating event, oscillation contour, and oscillation growth rate are defined for a particular case, the oscillation methodology is used to simulate the response of the LPRMs and peak bundle. To determine the peak bundle oscillation magnitude that results in the specified setpoint overshoot, the trip system design must be specified. This design includes the assignment of LPRMs to RPS trip channels, any averaging of LPRMs (e.g., APRMs, OPRMs), evaluation of the trip system signal using algorithms designed to detect oscillations (see Appendix B), and the trip system setpoints. The trip system stability detection algorithm and trip setpoints are important in determining the overshoot distribution. The assignment of LPRMs to RPS trip channels and any averaging of LPRMs is simulated by the oscillation methodology so that the trip system response is accurately represented. Appendix A provides examples of trip system designs. Since the channels of the trip system will not all have the same response during the oscillations, the most responsive channel is conservatively assumed to fail, and the next most responsive channel is assumed to initiate the trip during the oscillations. This channel's response is combined with the required signal overshoot to determine the peak bundle oscillation magnitude.

6.3.2.4 LPRM Failures

Because the detection and suppression systems are based on LPRMs, failed LPRMs that are out-of-service may affect the responsiveness of the systems. To account for this, each case is assumed to have a fraction of the LPRMs failed and bypassed in the respective trip systems. The number of failed LPRMs is based on a random sample from a distribution which represents the expected LPRM failure rate. Plant data have been evaluated to determine the expected LPRM failure rates. Based on a survey of eight plant designs covering a wide range of plants and operating cycles, failure rate distributions have been developed for beginning of cycle, middle of cycle and end of cycle conditions. As expected, the failure rate for the end of cycle is the highest. The distributions do not show any bias relative to plant size, and show a downward trend with time (i.e., reduction in LPRM failures over the last few years). The distribution of composite LPRM failure rates from the plant data is shown in Figure 6-28.

Once the LPRM failure rate has been randomly selected for a specific case, the location of the failed LPRMs is determined by assuming each LPRM has an equal probability of failure. This results in a random distribution of failed LPRMs. This is also consistent with plant data which showed no particular bias toward LPRM axial or radial location. Failed LPRMs are assumed to be bypassed in the respective trip system channel and therefore do not contribute to the channel response.

6.3.2.5 MCPR Performance

The TRAC-G model is used to generate a correlation for CPR change as a function of peak bundle oscillation magnitude. This correlation is generated with a sufficient number of cases to adequately characterize the CPR performance for various plant and fuel designs. In particular, the correlation is evaluated for its sensitivity to channel hydrodynamic decay ratio. Examples of correlations that have been developed based on previous calculations using the TRAC-G model are shown in Figure 6-11. For a particular plant and fuel design, a representative correlation will be specified, where the correlation may be described by a distribution of CPR changes for a given peak bundle oscillation magnitude. For a given case being analyzed by the oscillation model, the change in CPR during the oscillations will be determined from the appropriate correlation using the peak bundle oscillation magnitude including the effects of signal overshoot. The final MCPR for the specific case can then be determined by:

$$FMCPR = IMCPR * (1.0 + \Delta/IMCPR) \quad (6\text{-}8)$$

where

FMCPR = Minimum CPR during the oscillations

IMCPR = Initial MCPR prior to the onset of oscillations

Δ/IMCPR = Relative change in CPR during oscillations.

6.3.3 Examples of Monte Carlo Analysis

To demonstrate the application of the detection and suppression methodology, sample calculations are performed for a 560 bundle BWR/4 plant. The following inputs are assumed for the analysis.

(1) Initial Conditions

As discussed in Section 6.3.2.1, the reactor is assumed to begin operation at one of two conditions: (1) full power or (2) high power/low flow conditions expected during startup. It is assumed that 95% of the time the reactor is operating at full power and 5% of the time at the startup conditions. The reactor is assumed to be operating at the maximum allowable rod line (e.g., 110% of rated), since this results in the most limiting initial MCPR just prior to oscillation onset. The rated power MCPR operating limit is assumed to be 1.25. For a BWR/4 with a standard K_f curve, the operating limit at 40% core flow (assuming a maximum flow runout of 102.5% of rated) is 1.44. The initiating event is a two recirculation pump trip which results in an increase in MCPR as flow reaches natural circulation. The change in CPR during this flow reduction is simulated by data from process computer calculations during flow reduction events at operating BWRs (Figure 6-19) which are characterized by a normal distribution. The radial peaking factor is based on GE 3D BWR Simulator calculations that were used to generate the oscillation contours in Table 6-4. The radial peaking factor is also assumed to be normally distributed.

(2) Oscillation Contours

Six oscillation contours (three NESW and three NWSE modes) are chosen from the contours generated for the 560 bundle core size (Table 6-4). The contours for Cycle 9 and Cycle 12 conditions were chosen. The axis of oscillation symmetry is a diagonal for each case (NWSE/NESW modes), which is a conservative assumption for plants that operate in B sequences, since the NS and EW modes (which show improved LPRM response) could also be expected to occur.

(3) Oscillation Growth Rate

The oscillation scenarios described in Section 6.3.2.2 are used to simulate the potential oscillation magnitude growth rates. There are 22 scenarios which range in growth rates from 1.05 to 1.60. Each scenario has a random noise component superimposed on the oscillation which is representative of noise levels expected during operation.

(4) Trip System Definition

An OPRM, (Appendix A), is used to detect the oscillations and initiate the ASF. The LPRM assignments to OPRM channels for the 560 bundle core are shown in Figures 6-29 and 6-30. The high-low-high detection algorithm defined in Appendix B is used with a maximum trip setpoint of 1.20 (peak-to-average). Based on the 22 oscillation scenarios and the specified trip algorithm and setpoints, the distribution of peak OPRM signals prior to mitigation is shown in Figure 6-27. The second peak following ASF initiation is chosen to define the distribution, since the BWR/4 technical specification scram times are similar to the oscillation period. It is assumed that, during the oscillations, the single worst RPS channel failure occurs.

(5) LPRM Failures

Average LPRM failure rates used in this example have been determined from plant data for beginning, middle and end of cycle as 6%, 8%, and 9% respectively. The distribution of LPRM failure rates is also based on plant operating data and is similar to the distribution shown in Figure 6-28. The failed LPRMs are assumed to be randomly distributed throughout the core.

(6) MCPR Performance

The MCPR performance during oscillations is based on Curve 1 of Figure 6-11. This curve represents a least squares fit of the calculational results from TRAC-G analysis of a BWR/5 with loose inlet orifice diameter (2.43 inches).

(7) Results

The inputs for the example calculations are summarized in Table 6-5. The various distributions are randomly sampled to generate 5000 cases, with the result of each case being a final MCPR. A statistical evaluation of the results is performed to determine the $MCPR_{95/95}$ result. The results of the analysis are summarized in Table 6-6, where the mean value of the MCPR response is 1.404. The $MCPR_{95/95}$ value is determined by applying an appropriate tolerance factor to the standard deviation of the 5000 cases

where

$$MCPR_{95/95} = MCPR_{mean} - k*\sigma \tag{6-8}$$

Since only 22 oscillation scenarios are used, it is assumed that the 5000 cases only represent 22 independent cases and, therefore, 2.35σ is subtracted from the mean to determine the $\mathrm{MCPR}_{95/95}$ value of 1.23 for this example.

6.4 PLANT- AND CYCLE-SPECIFIC APPLICATION OF GENERIC ANALYSIS

Section 6.3 summarizes the application of the oscillation methodology for a specific core size and Technical Specification limits. Although this procedure could be applied to any individual plant, generic analyses will be performed for plants with similar characteristics. The primary characteristic that distinguishes a plant group is the core size. Because of the wide range of MCPR operating limits and possible trip system designs and setpoints, it is necessary to perform sensitivity studies to ensure that all plants within a plant group are initially bounded by the results. In general, these sensitivities will be performed for varying MCPR operating limits and trip system algorithms and setpoints. These studies will establish acceptable trip system setpoints as a function of MCPR operating limit. An example of the form in which the generic results will be presented is shown in Figure 6-31 for the OPRM system (Appendix A).

To confirm that the generic results are applicable to a plant within the group, a comparison of the major parameters affecting the system response and CPR performance must be made. If all parameters are within a defined range, the appropriate trip system setpoints can be applied to the specific plant. This section discusses the key parameters that must be evaluated to determine the applicability of the detection and suppression system setpoints.

(1) Initial Conditions

The generic analyses will cover a sufficient range of MCPR operating limits and allowable rod lines to ensure that current and expected core and fuel designs are covered. If a plant's MCPR operating limit changes, the acceptability of existing setpoints can be confirmed from the generic analyses. Other parameters associated with initial conditions are relatively minor contributors to the overall results and are not expected to vary significantly as a function of fuel and core design.

(2) Oscillation Contours

The variation in oscillation contours is primarily a function of neutron leakage and control rod patterns. The variation in oscillation contour for a 560-bundle core is shown in Figure 6-21. A similar result is also found when contours are compared from different size plants. The oscillation contours from a range of core sizes are shown in Figure 6-32. The oscillation magnitude is plotted as a function of the relative distance from the core center for LPRMs that are located along a diagonal which is perpendicular to the axis of oscillation symmetry. These results demonstrate that the variation in oscillation contours as a function of core size is similar to the variation due to power distribution and is primarily controlled by the cylindrical geometry of the core. A generic set of contours will be used for the generic analysis and no additional evaluations are required during plant- and cycle-specific confirmations.

(3) Oscillation Growth Rate

The generic analyses will be performed using the range of oscillation growth rates discussed in Section 6.3.2.2, which covers the range of expected growth rates. These growth rates are not expected to vary significantly as a function of core and fuel design and, therefore, no additional confirmations are required.

(4) Trip System Definition

The generic analyses will explicitly cover the trip system configurations described in Appendix A, detection algorithms, and range of expected setpoints. Any modifications outside the evaluated range will require additional analysis.

(5) LPRM Failures

The LPRM failure rates have been determined from actual plant data and have shown a gradual decrease over time. Restrictions on the number of LPRMs required to be operable for accurate power distribution monitoring and APRM operability provide sufficient control on the expected failure rates. A relatively large fraction of the cases evaluated in the Monte Carlo simulations (10-15%) result in LPRM failures in excess of those allowed by Technical Specifications. This demonstrates the conservatism in the basic assumptions. In addition, sensitivity studies have been performed which show that the overall impact of failed LPRMs is small for the OPRM and LPRM-based systems described in Appendix A. Therefore, the assumptions in the generic analysis are sufficient to preclude the need for future confirmations.

(6) MCPR Performance

The two most important parameters in determining the final MCPR are the initial MCPR and the change in MCPR during oscillations. Generic correlations will be developed for a range of fuel designs which describe the change in CPR as a function of oscillation magnitude. These correlations will be presented as a function of the important parameters which affect the response. It is expected that the primary parameter will be channel decay ratio, since this is a direct measure of the hydraulic responsiveness of the channel, which dominates the CPR response. The generic analyses will be performed with a range of fuel designs representing the range of expected fuel response for current fuel designs. For future core and fuel designs, parameters will be defined that must be confirmed to be within the defined ranges of the generic analysis. This may simply include the verification that the proposed fuel designs for the reload are within the defined range of acceptable designs.

For new fuel designs which have not been explicitly covered by the generic analysis, the CPR response must be evaluated. Details of the evaluation approach will be provided in a supplement to this licensing topical report.

Table 6-1

CALCULATION OF HARMONIC MODE EIGENVALUES - COMPARISON TO KNOWN ANALYTICAL SOLUTION

	Analytical Eigenvalue	BWR Simulator Eigenvalue
Fundamental Mode, λ_0	1.05471	1.05467
First Harmonic, λ_1	1.04302	1.04284
λ_0-λ_1	0.01169	0.01183
Fourth Harmonic, λ_4	1.03159	1.03115
λ_0-λ_4	0.02312	0.02352

Table 6-2

BWR/4 EXAMPLE - INITIAL CONDITIONS AND OSCILLATION CHARACTERISTICS

Core Thermal Power	50% of rated
Core Flow	30% of rated
Xenon Concentration	Full Power Equilibrium
Control Rod Pattern	All rods out
Cycle Exposure	8100 MWd/T
Radial Peaking Factor	1.37
Initial MCPR	1.84
Oscillation Mode	Regional NWSE Axis of Oscillation
Oscillation Contour	Figure 6-12
Oscillation Period	2.0 sec
Peak Bundle Oscillation Magnitude (P-M)/A	1.0
Axial Phase Lag (relative to A-level)	
B-Level	-23°
C-Level	-59°
D-Level	-82°

Table 6-3

BWR/4 EXAMPLE - RESULTS DURING OSCILLATIONS

Peak Bundle Oscillation Magnitude	110% of rated 161% of initial
Minimum CPR	1.35
Peak LPRM Signal	61% of scale 149% of initial
Peak APRM Signal	52.2% of rated
Peak OPRM Signal	133% of initial

Table 6-4

OSCILLATION CONTOURS

Core Size[a]	Cycle	Cycle[b] Exposure	Power/Flow (%/%)	Xenon[c]	Oscillation Axis
368	10	BOC	46/30	FP	NWSE/NESW
		MOC	46/30	FP	NS/EW
		MOC	47/30	FP	NWSE/NESW
		EOC	47/30	FP	NWSE/NESW
484	12	BOC	48/30	FP	NS/EW
		MOC	49/30	FP	NWSE/NESW
		EOC	53/30	FP	NWSE/NESW
560	12	BOC	50/30	FP	NWSE/NESW
		EOC	50/30	FP	NWSE/NESW
	9	MOC	50/30	FP	NWSE/NESW
	10	BOC	50/30	FP	NWSE/NESW
		MOC	50/30	FP	NWSE/NESW
		EOC	50/30	FP	NWSE/NESW
	10	BOC	50/30	FP	NWSE/NESW
		MOC	50/30	FP	NS/EW
		EOC	50/30	FP	NWSE/NESW
648	1	BOC	46/29	SS	NWSE/NESW
		BOC	56/31	SS	NS/EW
748	2	BOC	32/35	NO	NS/EW
		BOC	48/50	NO	NS/EW
		MOC	39/34	NO	NWSE/NESW
		MOC	50/30	NO	NWSE/NESW
		MOC	76/57	NO	NS/EW
764	2	BOC	45/28	FP	NWSE/NESW
	8	BOC	50/30	SS	NWSE/NESW
		MOC	50/30	SS	NWSE/NESW
		EOC	50/30	SS	NWSE/NESW

[a] Number of fuel bundles

[b] BOC = beginning of cycle
MOC = middle of cycle
EOC = end of cycle

[c] FP = full power equilibrium xenon
SS = equilibrium xenon at power/flow
NO = no xenon

Table 6-5

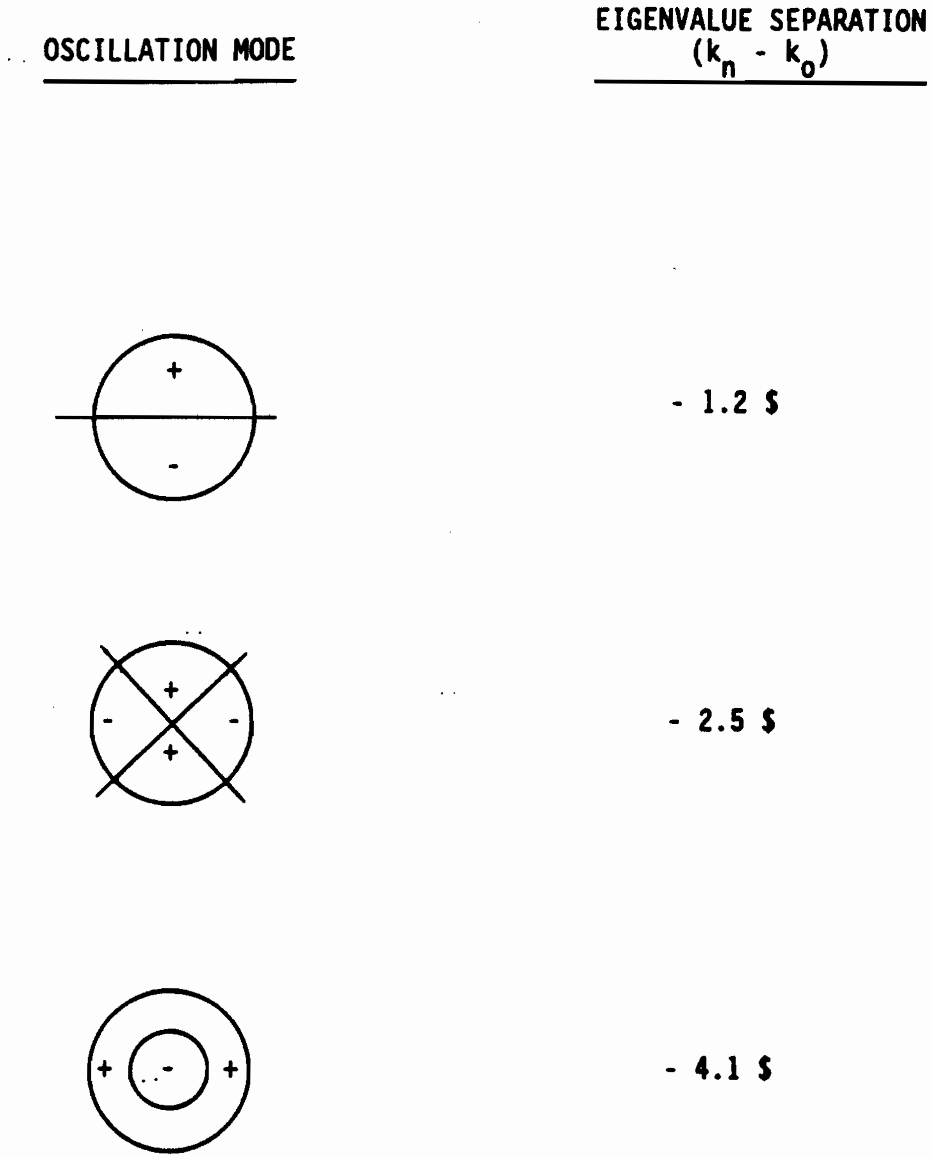
560 BUNDLE EXAMPLE - MONTE CARLO SIMULATION INPUTS

Initial Conditions	100% power/87% flow 62% power/40% flow	(95% probability) (5% probability)
Initial MCPR		
100% Power	1.25	Tech Spec limit
40% Flow	1.44	Tech Spec limit
CPR Change During Flow Reduction, DIDW (equation 6-6)	0.0065 0.0006	Average Standard Deviation
Radial Peaking Factor	1.415 0.083	Average Standard Deviation
Oscillation Contours	560 Bundle BOC/EOC-12 MOC-9	Table 6-4
Oscillation Growth Rates	22 scenarios	Growth rates of 1.05 to 1.60
Trip System Design	High-low-high Detection Algorithm (Appendix B)	Setpoints S1 = 1.10 S2 = 0.92 DR3 = 1.30 Smax = 1.20
Overshoot Distribution	Figure 6-27	
Average LPRM Failure Rate	6%, 8%, 9%	BOC, MOC, EOC
MCPR Performance	Curve 1	Figure 6-11

Table 6-6

560 BUNDLE EXAMPLE - MONTE CARLO SIMULATION RESULTS

Number of Cases	5000
MCPR	
Mean ($\bar{x}$)	1.404
Standard Deviation (σ)	0.073
Tolerance Factor (k) (22 independent cases)	2.350
95/95	1.232



k_o = fundamental mode eigenvalue

k_n = harmonic mode eigenvalue

FIGURE 6-1. EIGENVALUE SEPARATION OF HARMONIC MODES

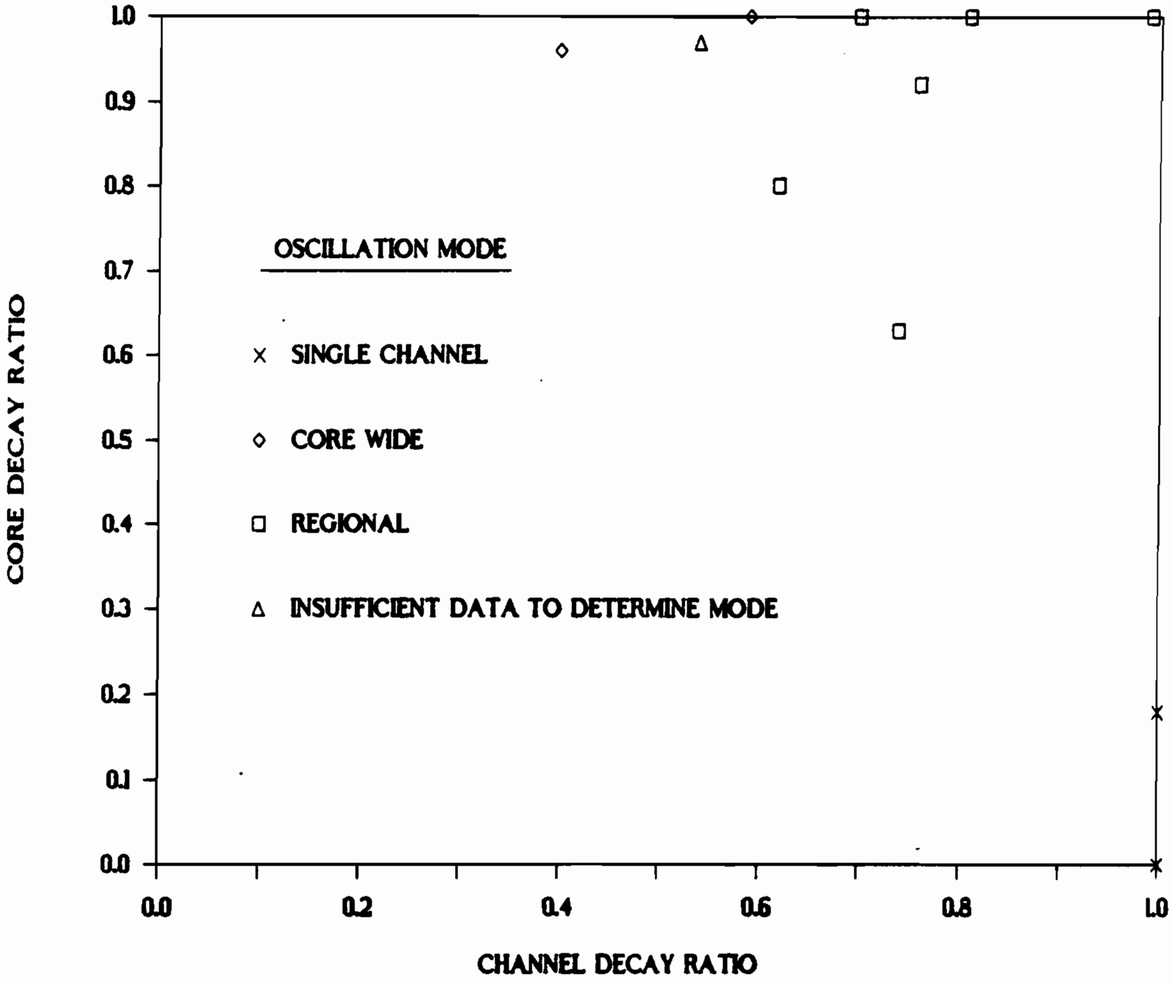


FIGURE 6-2. GE BWR STABILITY EXPERIENCE

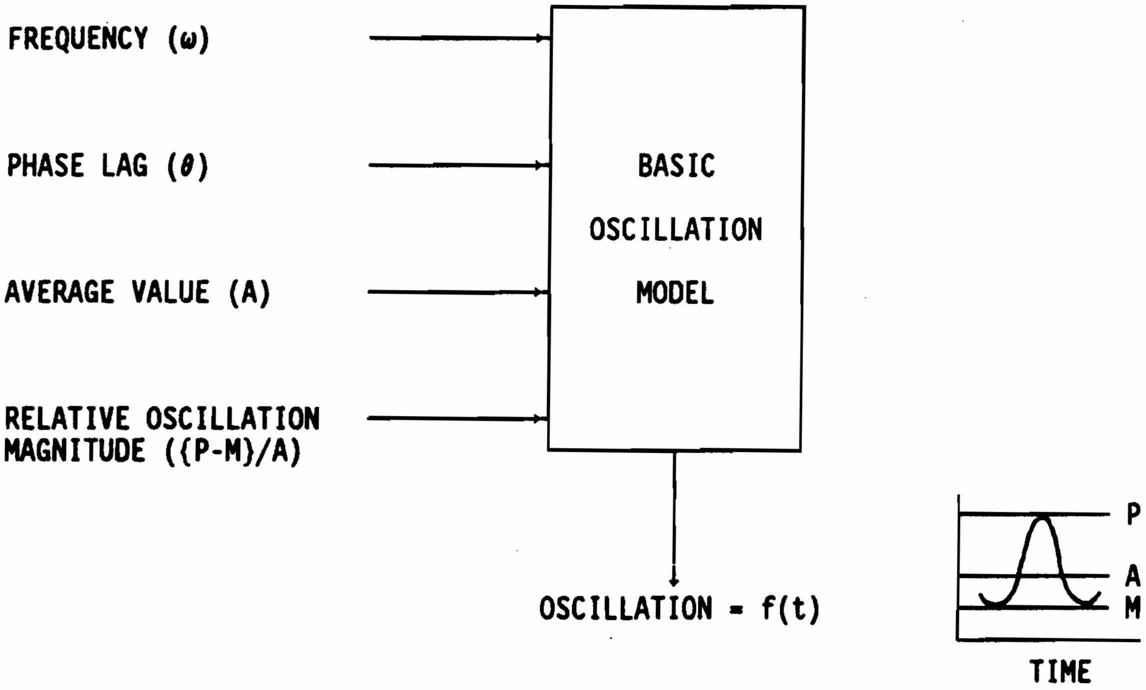


FIGURE 6-3. BASIC OSCILLATION MODEL

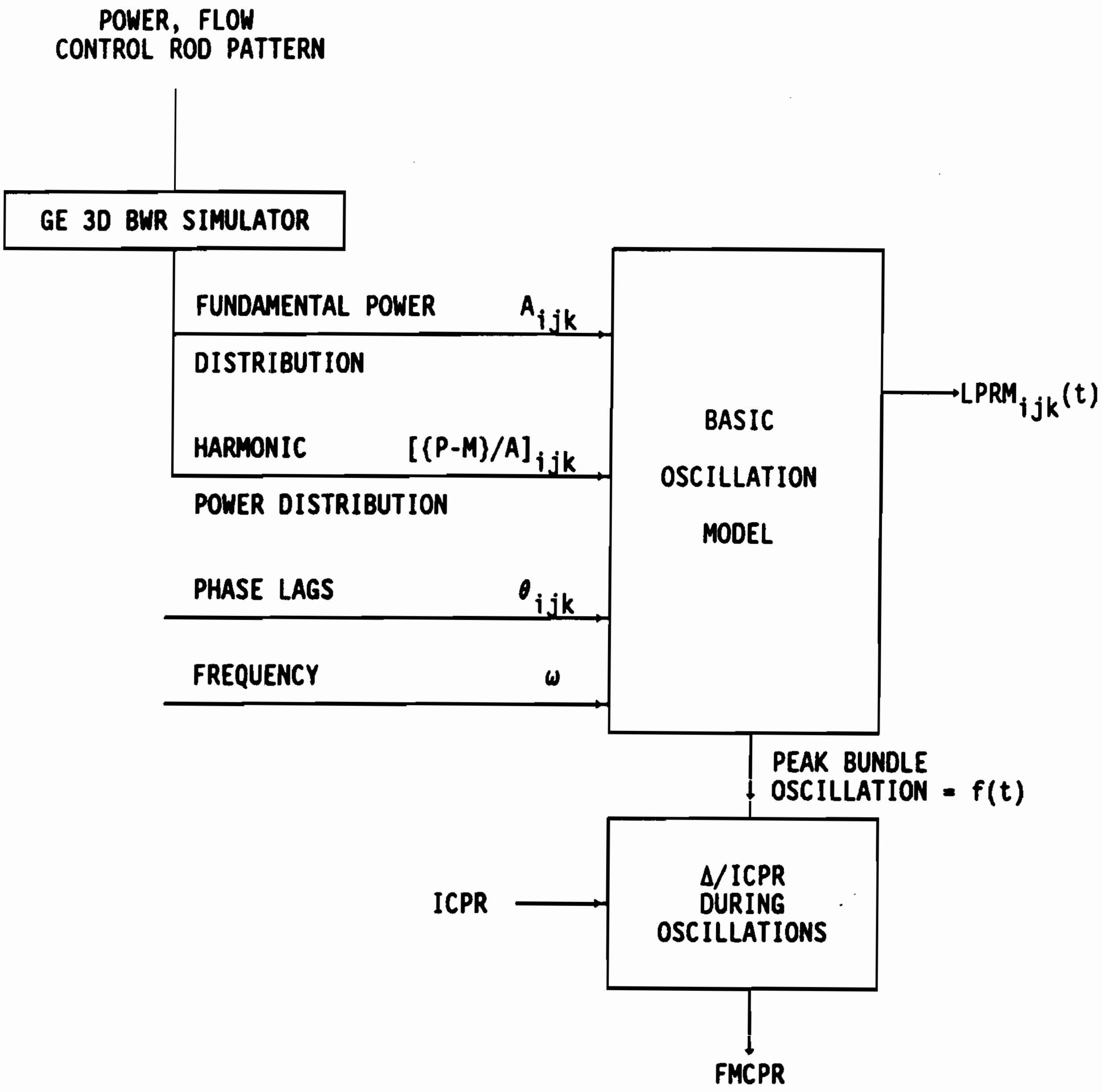


FIGURE 6-4. OSCILLATION METHODOLOGY BLOCK DIAGRAM

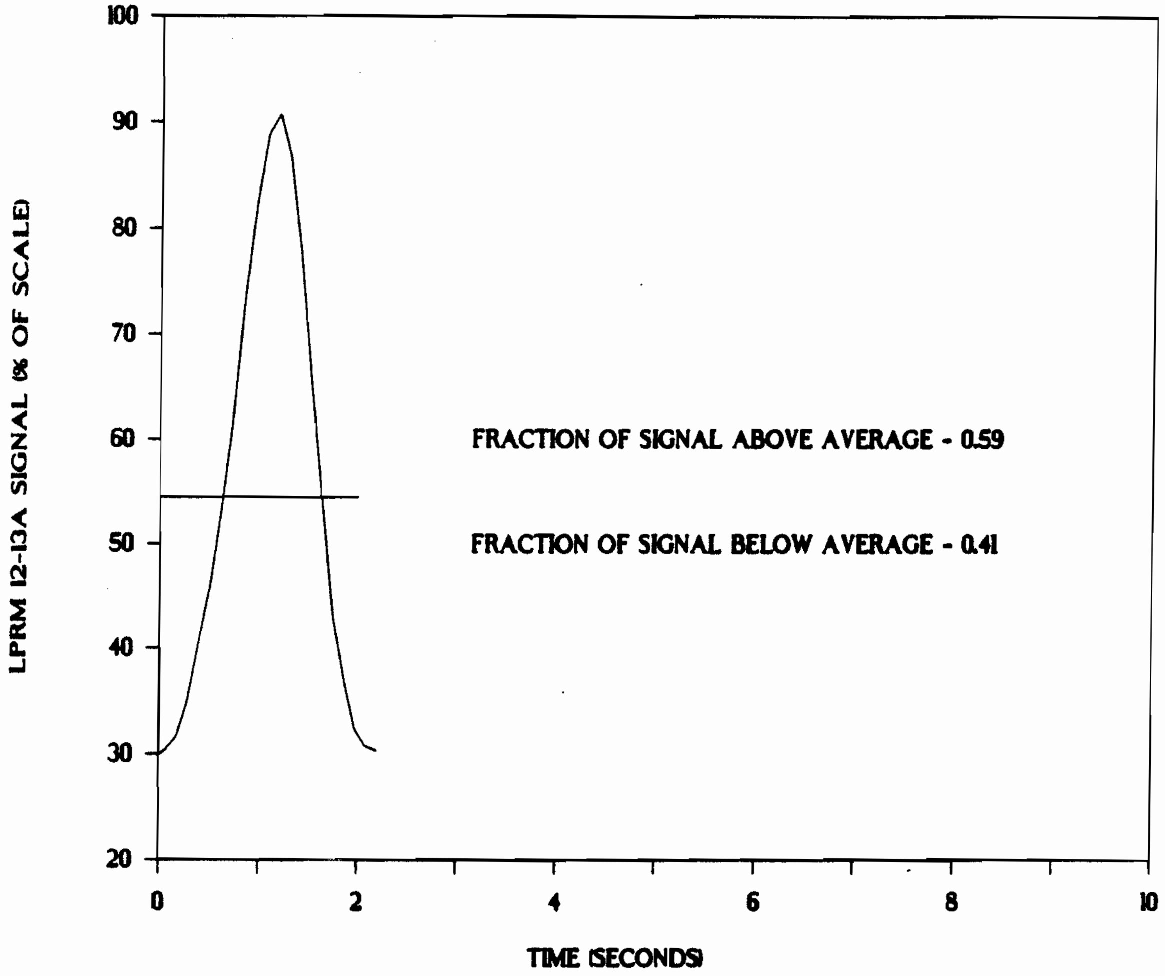


FIGURE 6-5. NON-LINEAR OSCILLATION AS MEASURED BY AN LPRM

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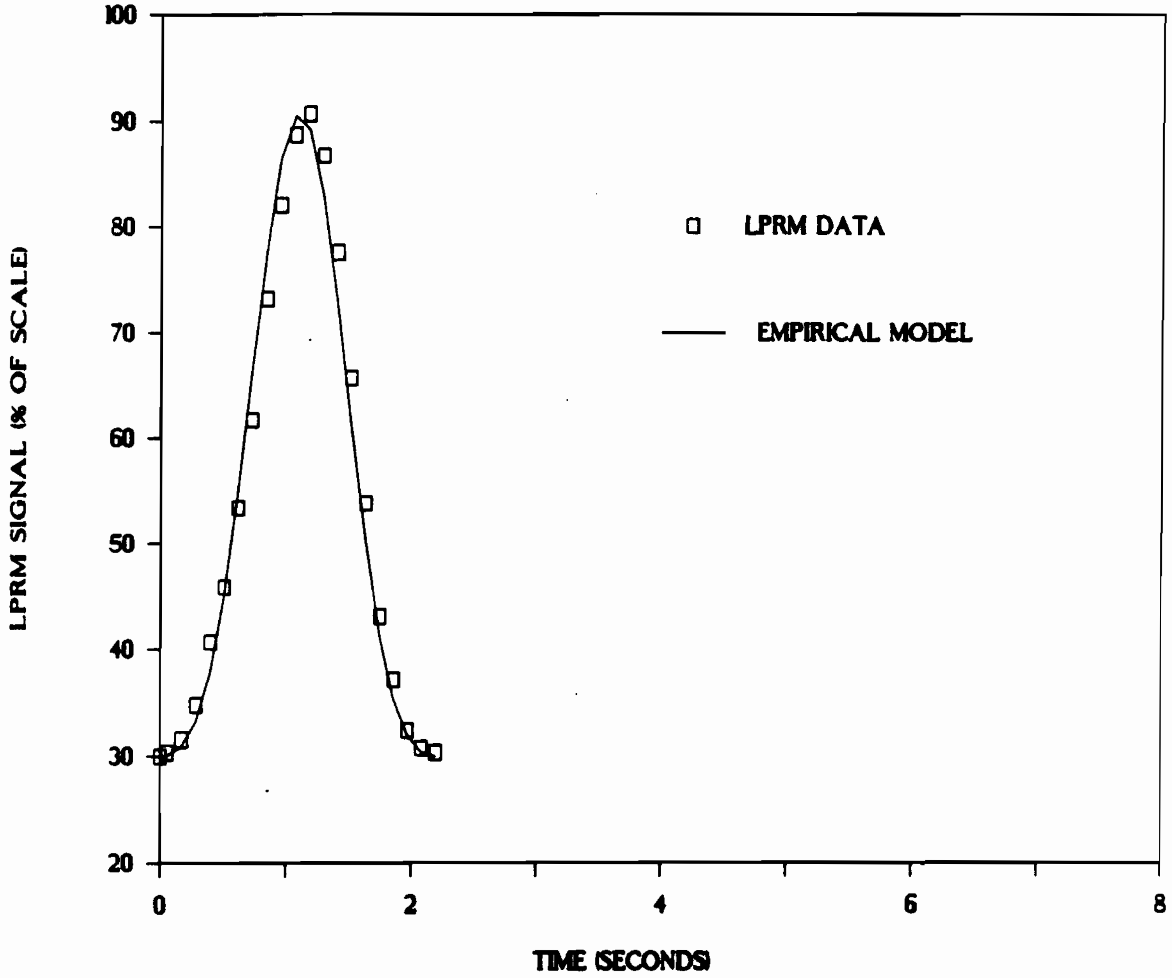


FIGURE 6-o. BASIC OSCILLATION MODEL - COMPARISON TO PLANT DATA

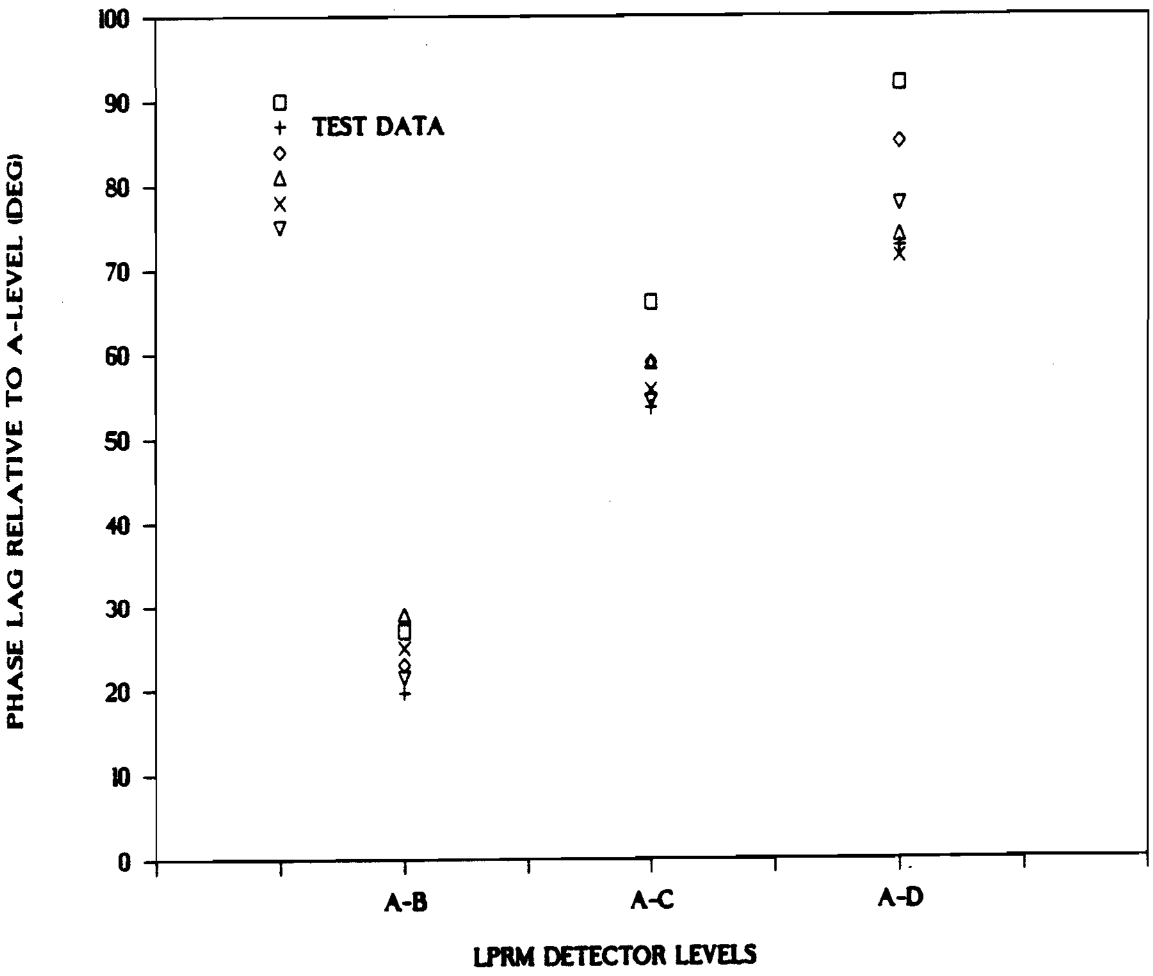


FIGURE 6-7. AXIAL PHASE LAGS

120

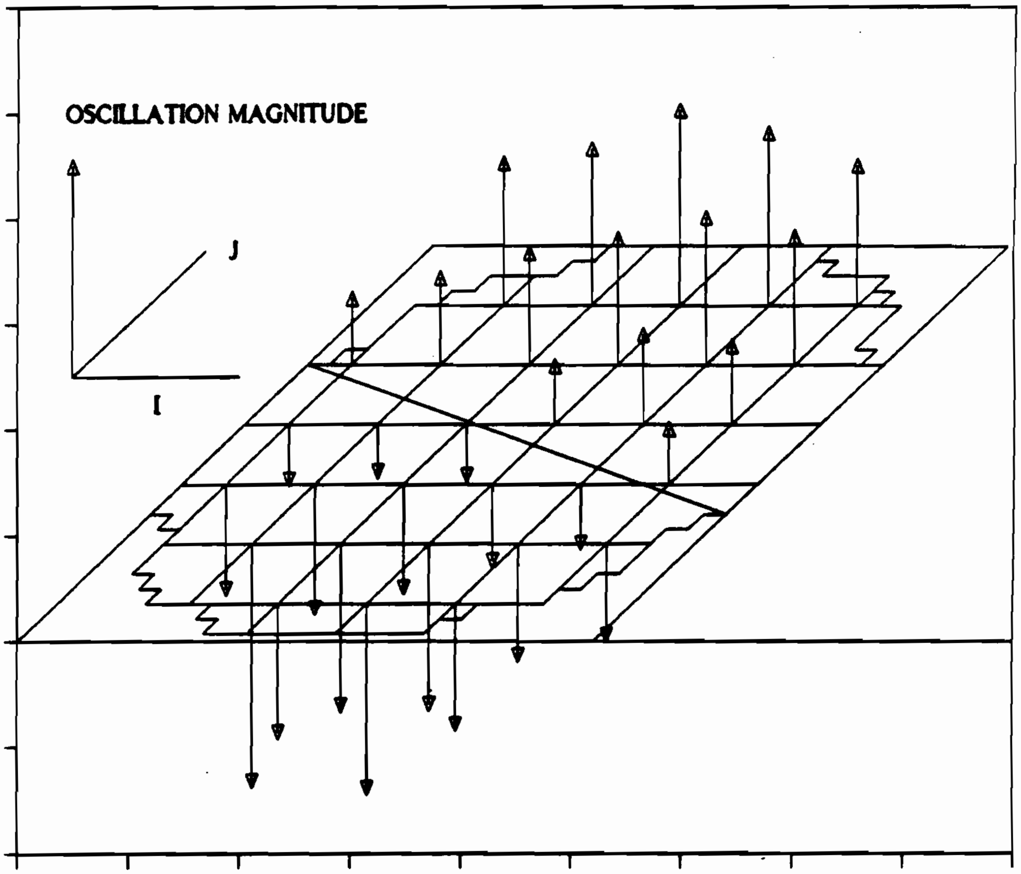
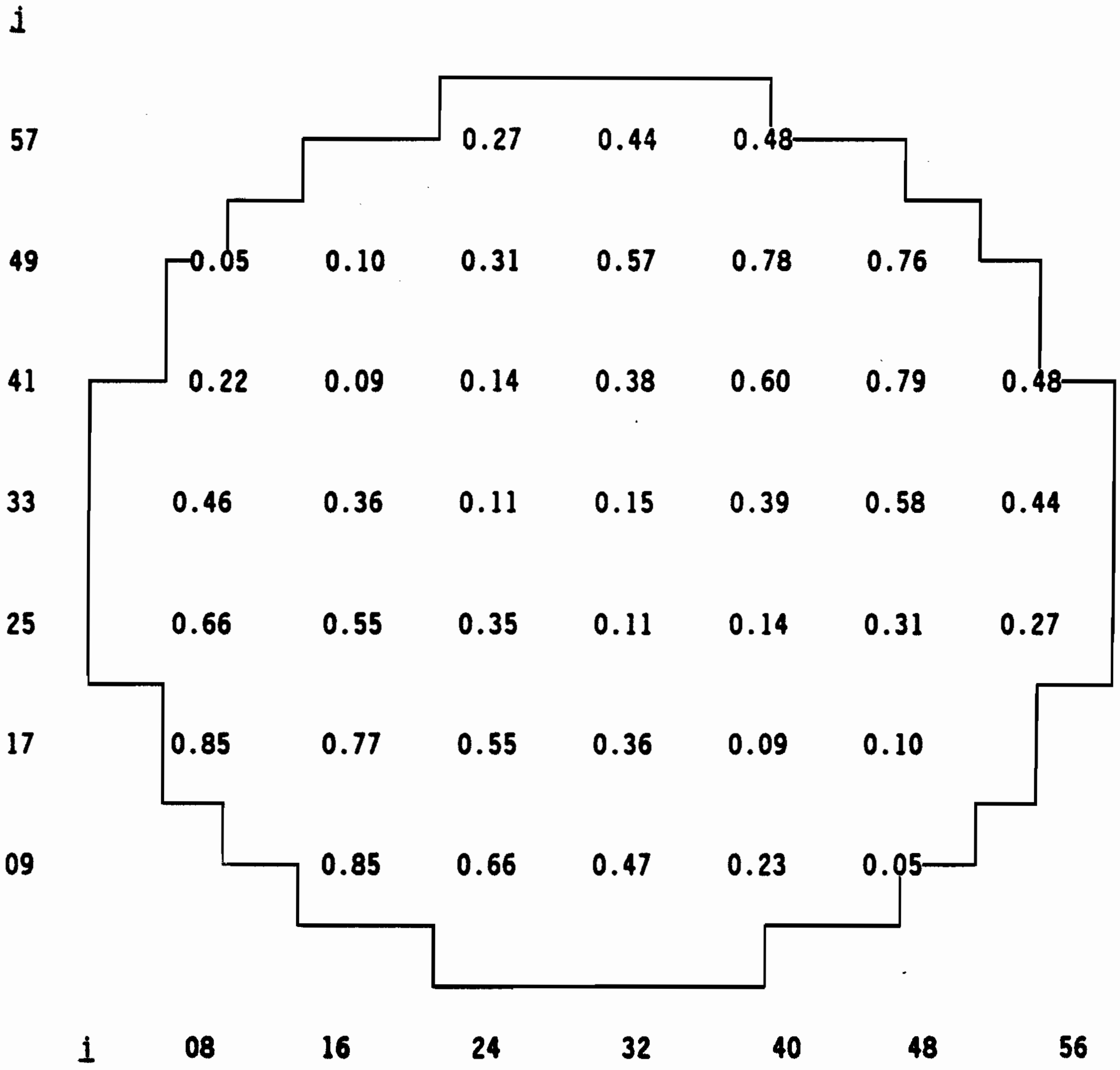


FIGURE 6-8. CAORSO CYCLE 2 TEST OSCILLATION CONTOUR



i							
57			0.27	0.44	0.48		
49	0.05	0.10	0.31	0.57	0.78	0.76	
41	0.22	0.09	0.14	0.38	0.60	0.79	0.48
33	0.46	0.36	0.11	0.15	0.39	0.58	0.44
25	0.66	0.55	0.35	0.11	0.14	0.31	0.27
17	0.85	0.77	0.55	0.36	0.09	0.10	
09		0.85	0.66	0.47	0.23	0.05	
i	08	16	24	32	40	48	56

0.XX = (P-M)/A OSCILLATION MAGNITUDE FOR LPRM(i,j) RELATIVE TO (P-M)/A OSCILLATION MAGNITUDE FOR PEAK BUNDLE

FIGURE 6-9. PREDICTED LPRM OSCILLATION CONTOUR

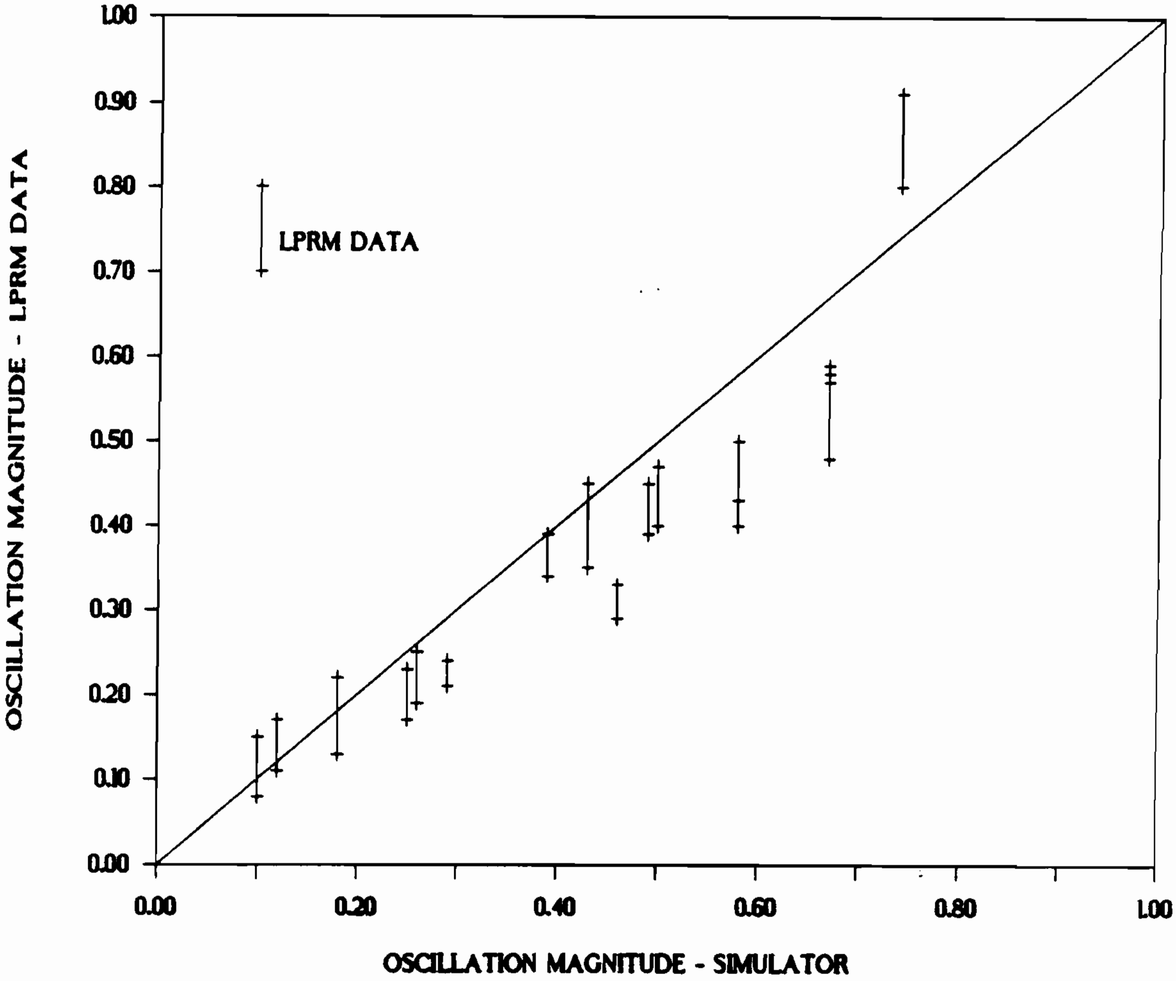


FIGURE 6-10. COMPARISON OF OSCILLATION CONTOUR - TEST DATA VERSUS GE 3D SIMULATOR PREDICTIONS

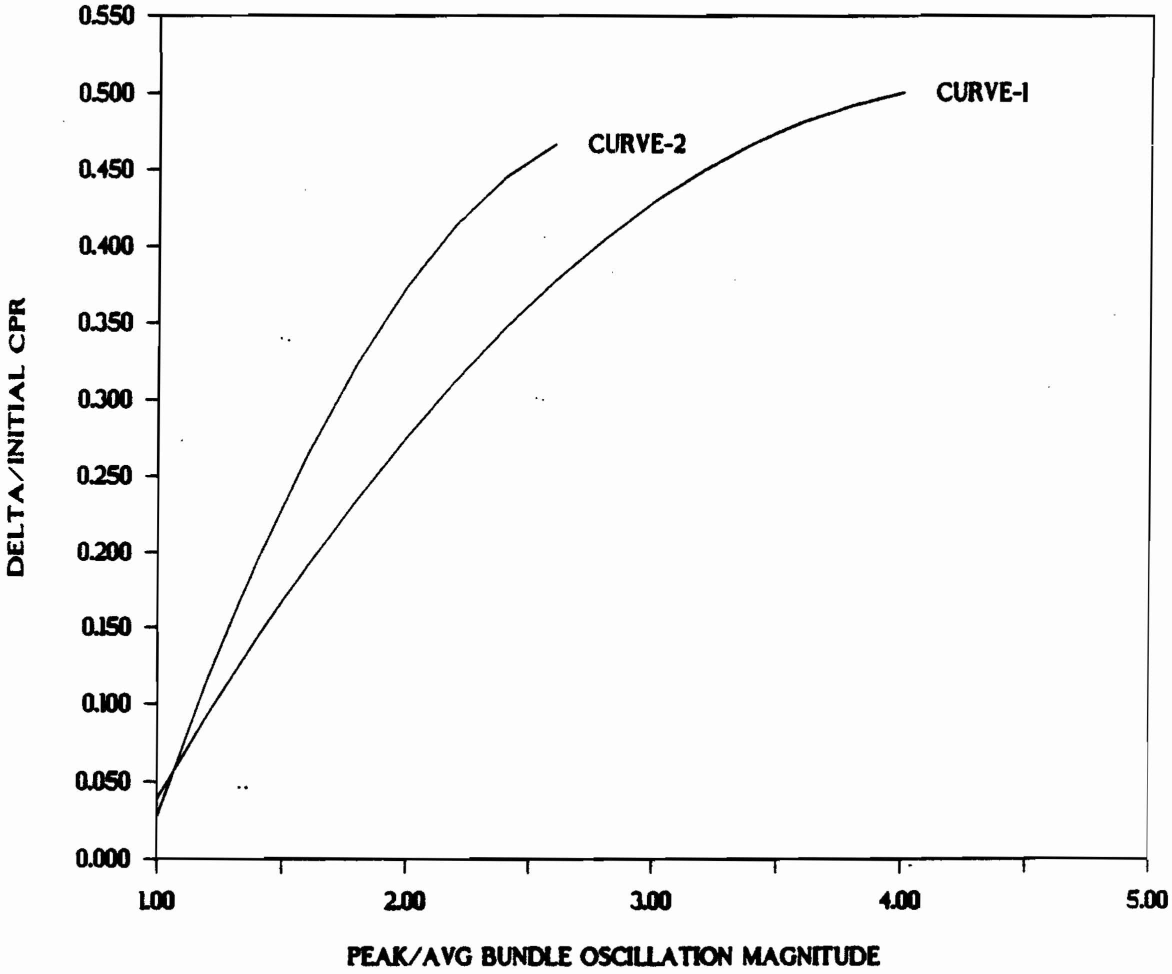


FIGURE 6-11. TYPICAL MCPR PERFORMANCE DURING OSCILLATIONS

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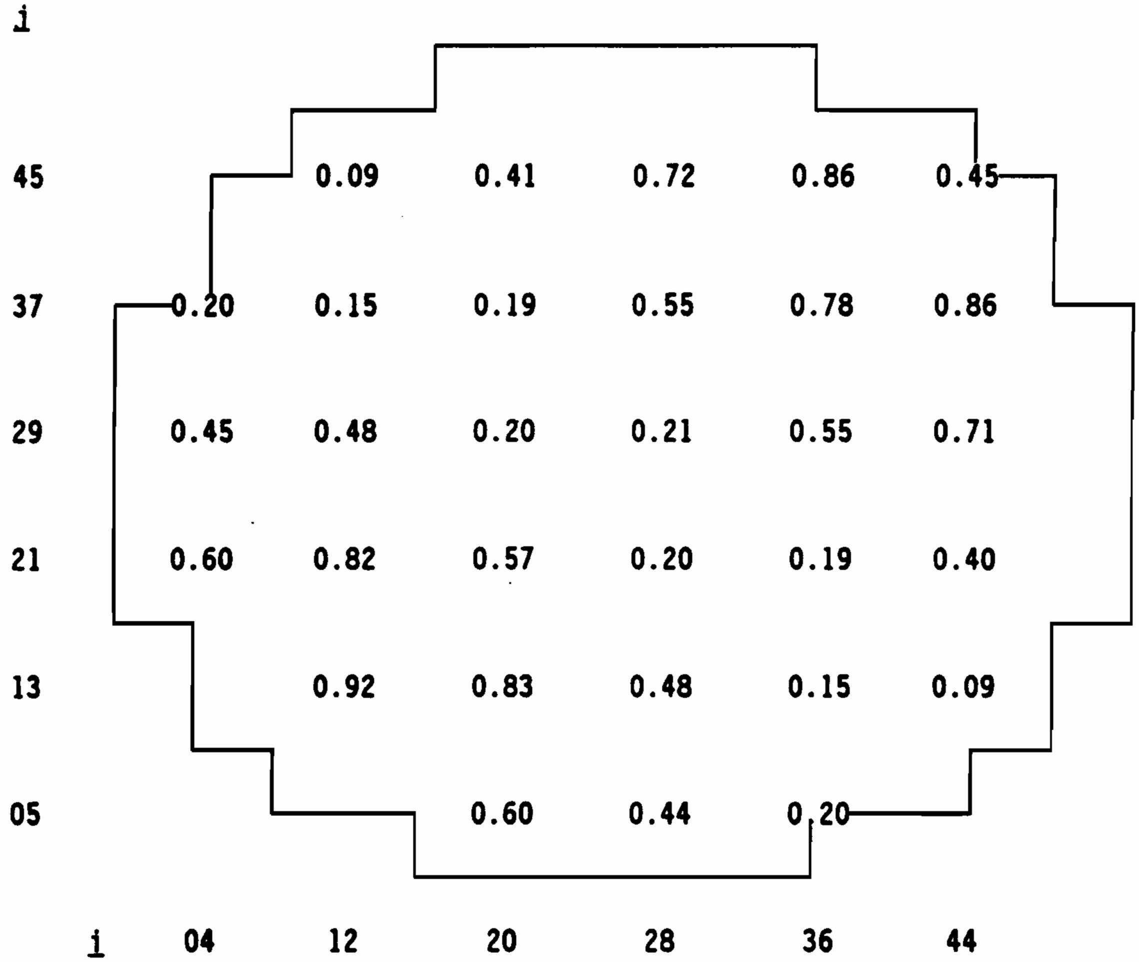

i						
45		0.09	0.41	0.72	0.86	0.45
37	0.20	0.15	0.19	0.55	0.78	0.86
29	0.45	0.48	0.20	0.21	0.55	0.71
21	0.60	0.82	0.57	0.20	0.19	0.40
13		0.92	0.83	0.48	0.15	0.09
05			0.60	0.44	0.20	
i	04	12	20	28	36	44

0.xx = (P-M)/A oscillation magnitude for LPRM(i,j) relative to (P-M)/A oscillation magnitude for peak bundle

FIGURE 6-12. BWR/4 EXAMPLE CONTOUR

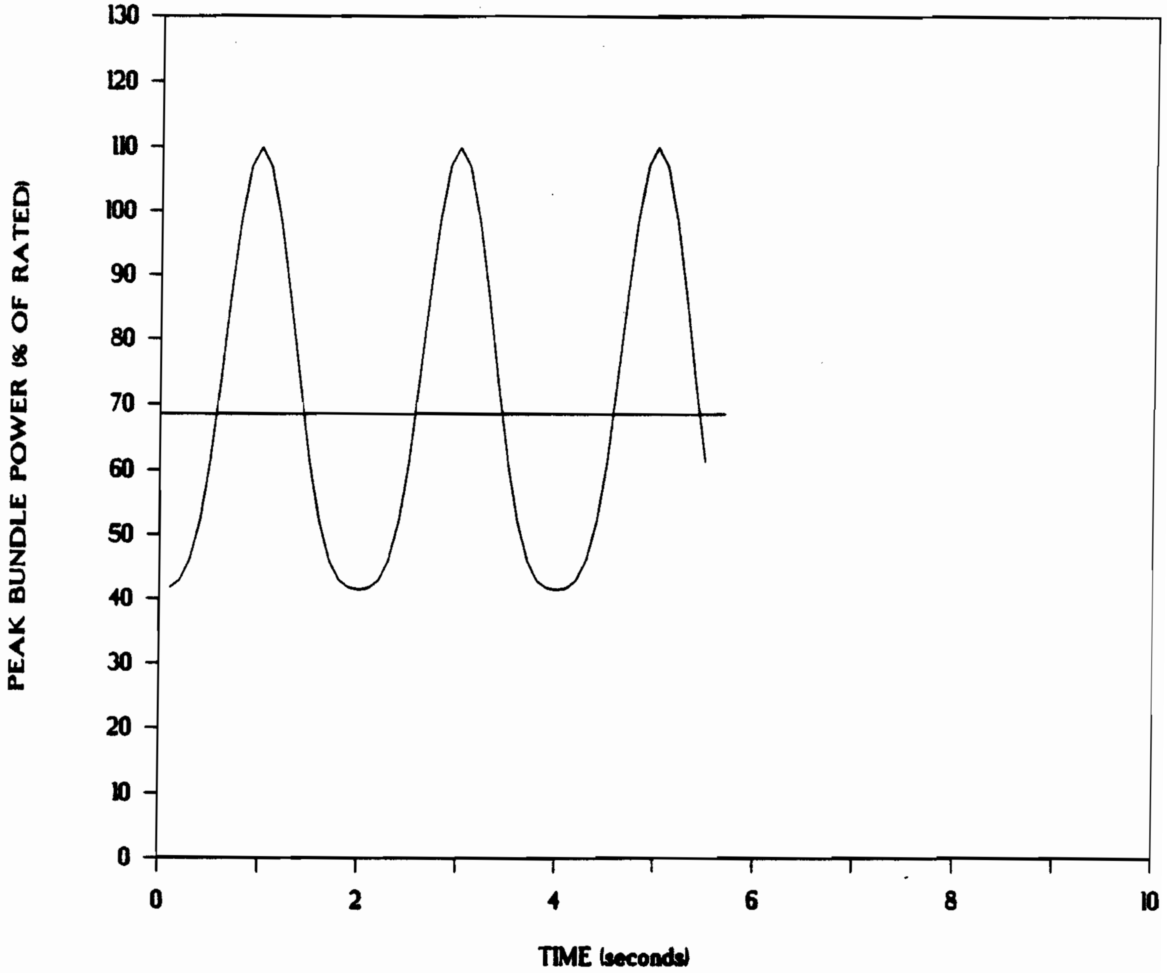

FIGURE 6-13. BWR/4 EXAMPLE - PEAK BUNDLE OSCILLATION MAGNITUDE

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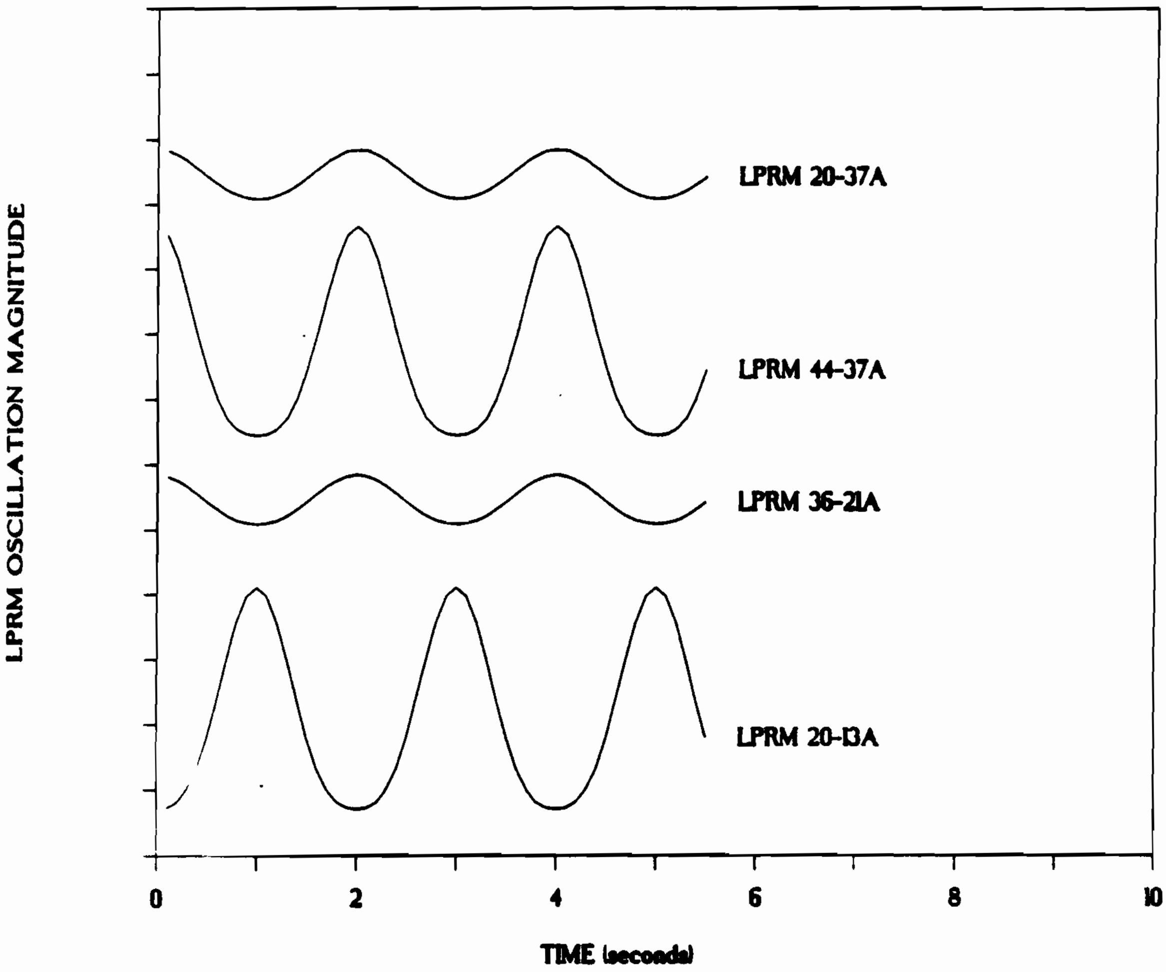

FIGURE 6-14. BWR/4 EXAMPLE - LPRM OSCILLATIONS (RADIAL DISTRIBUTION)

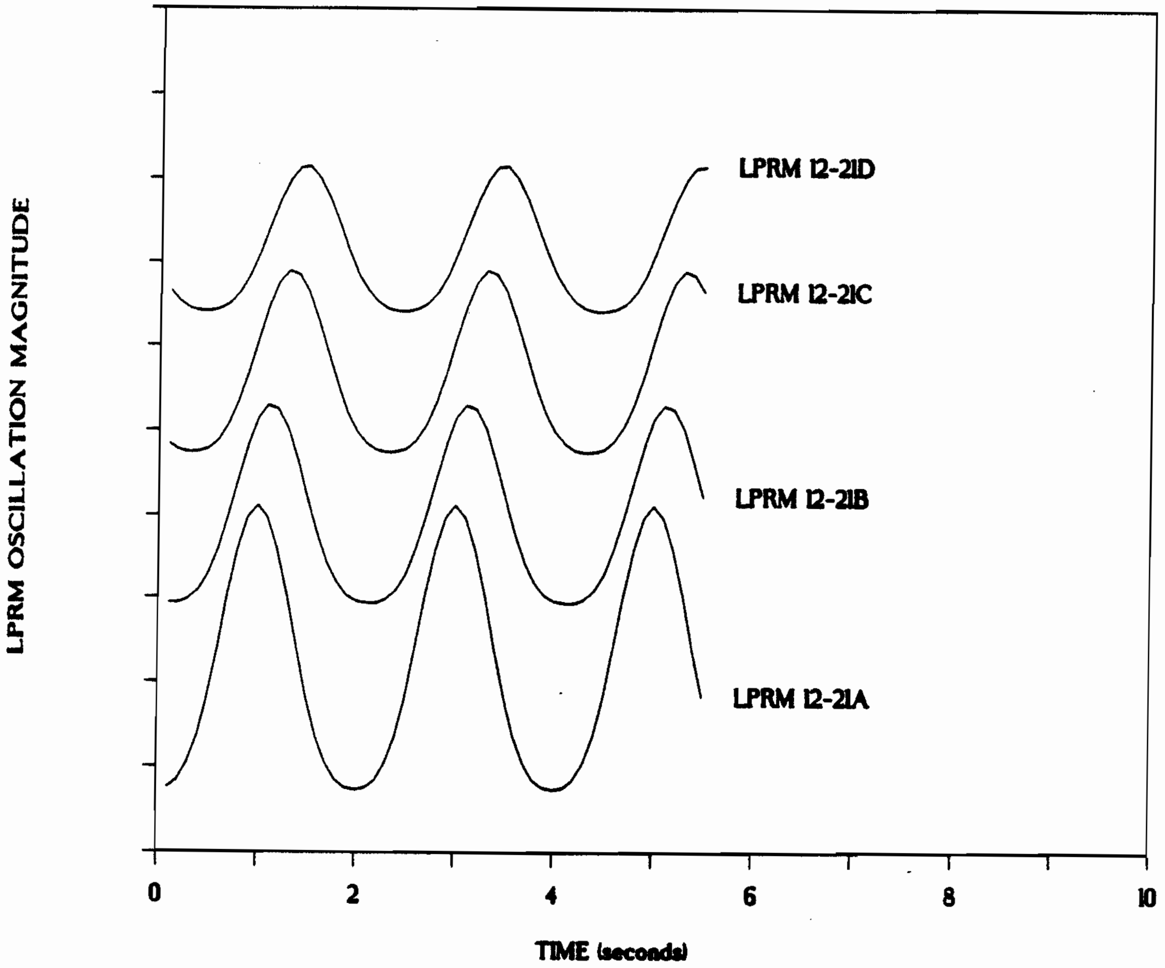

FIGURE 6-15. BWR/4 EXAMPLE - LPRM OSCILLATIONS (AXIAL DISTRIBUTION)

128

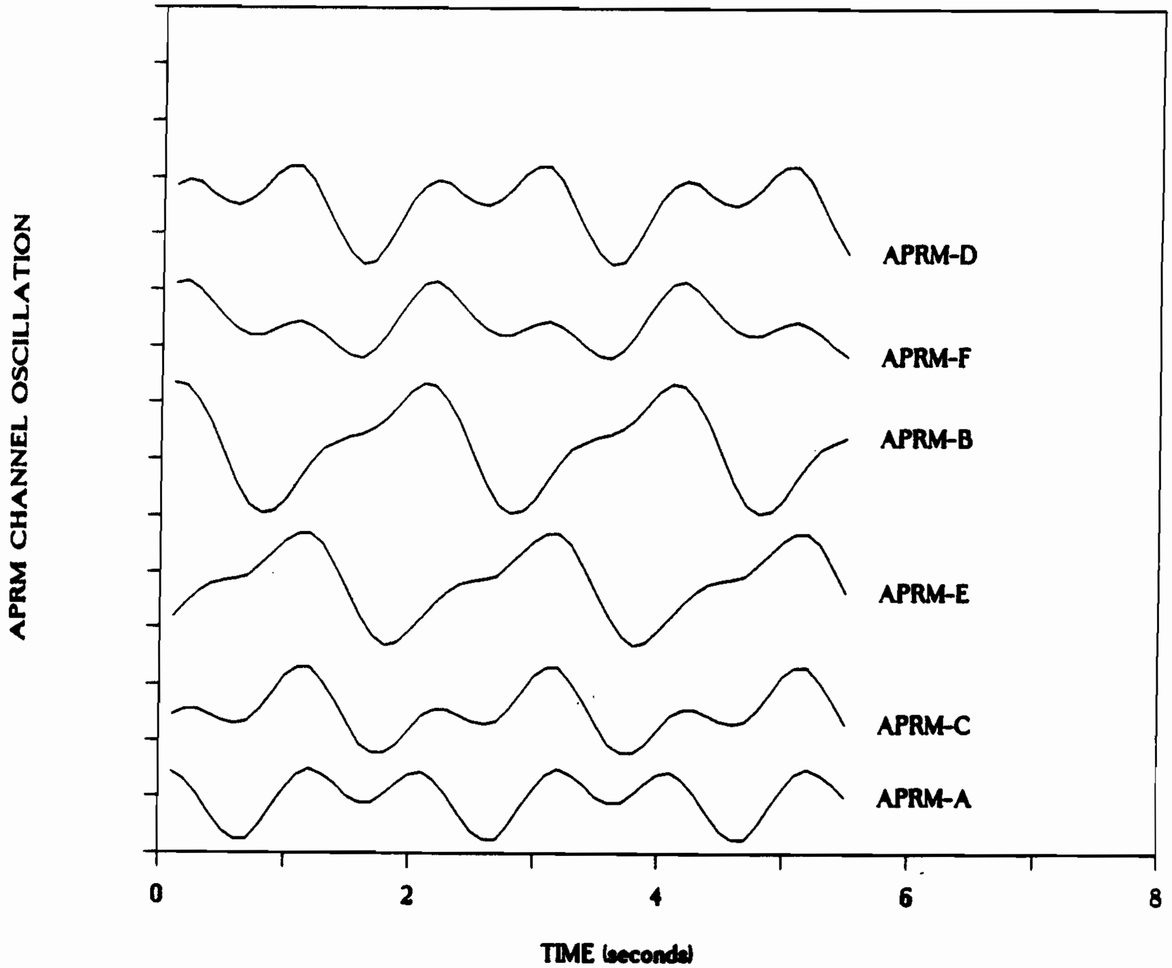

FIGURE 6-16. BWR/4 EXAMPLE - APRM OSCILLATIONS

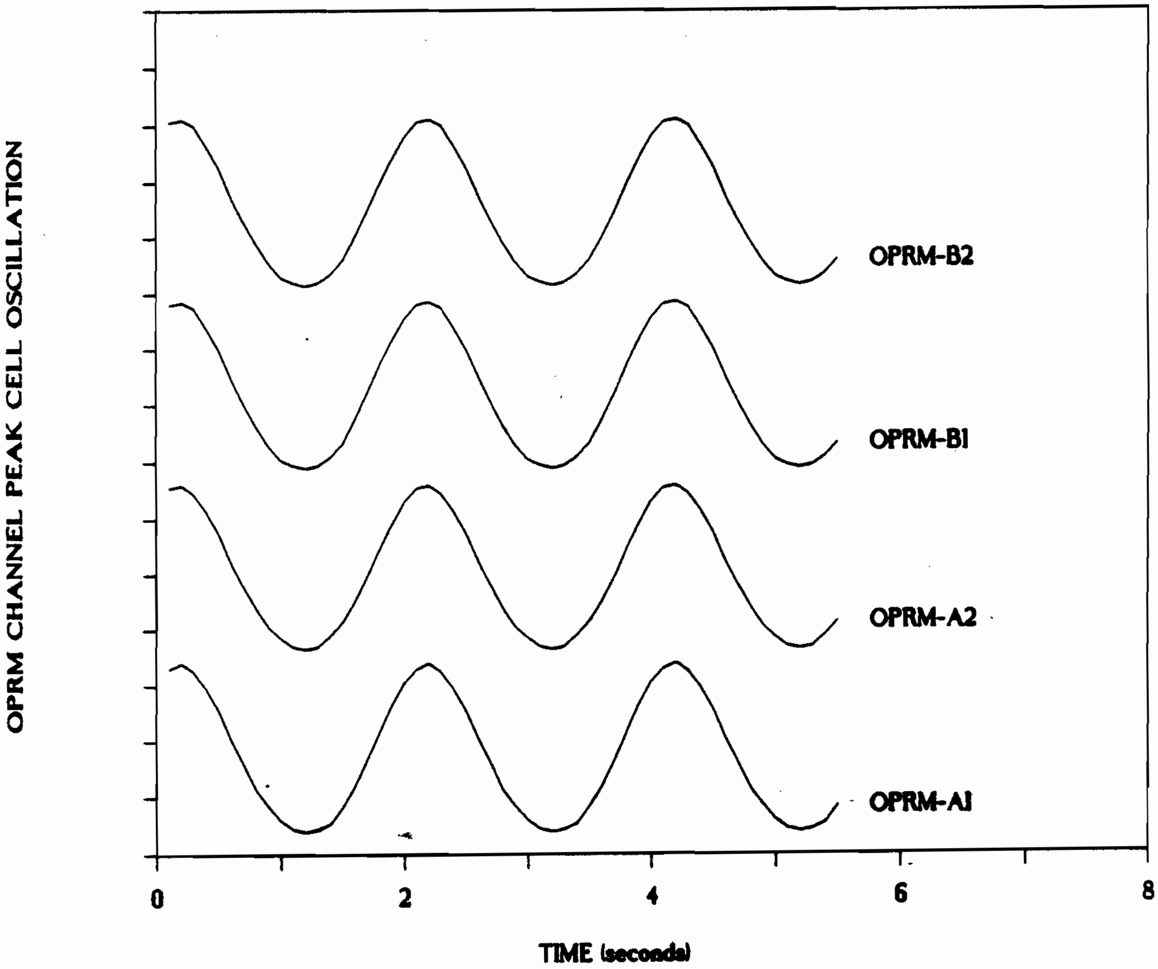

FIGURE 6-17. BWR/4 EXAMPLE - OPRM OSCILLATIONS

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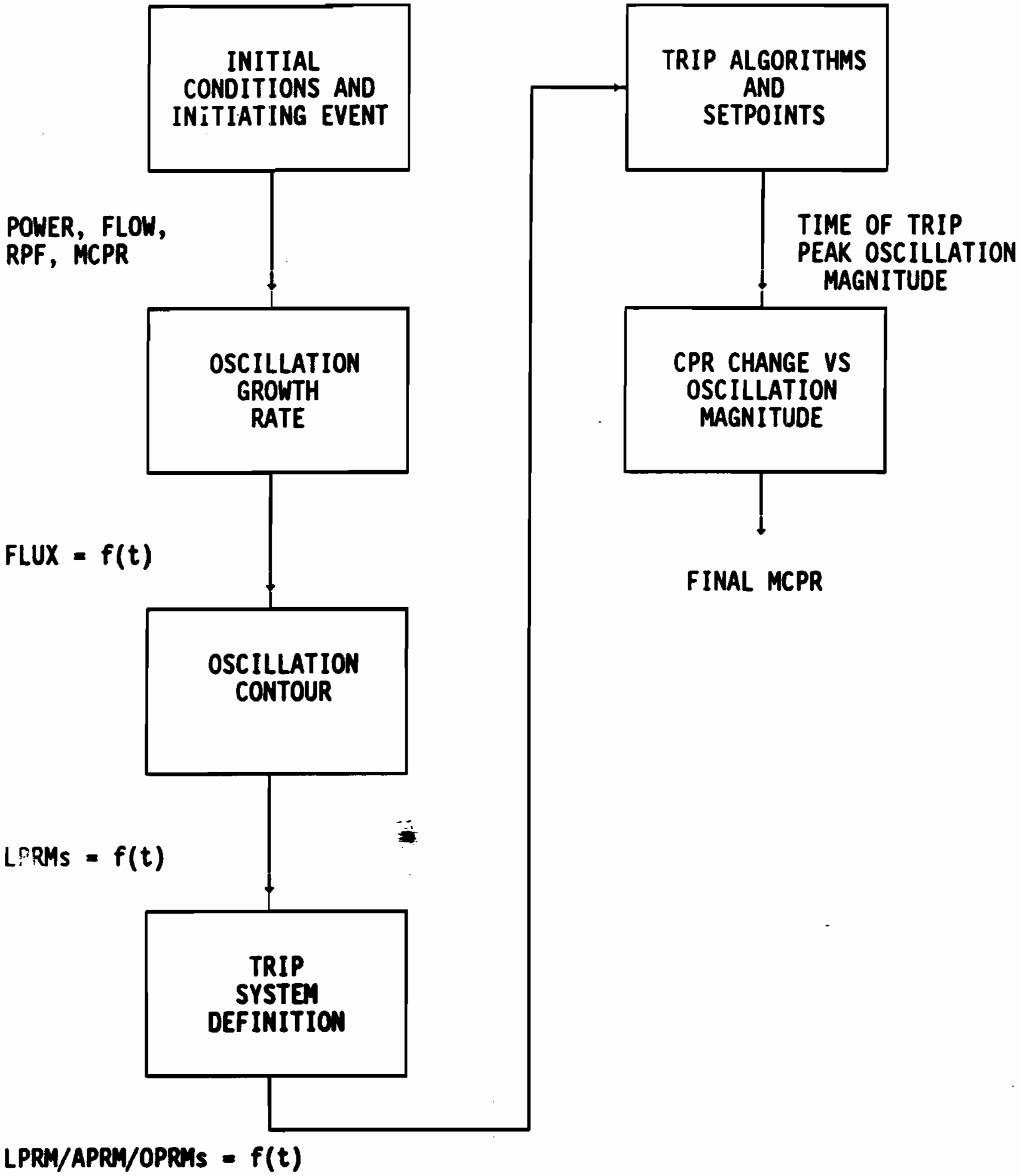

FIGURE 6-18. OSCILLATION METHODOLOGY ROADMAP

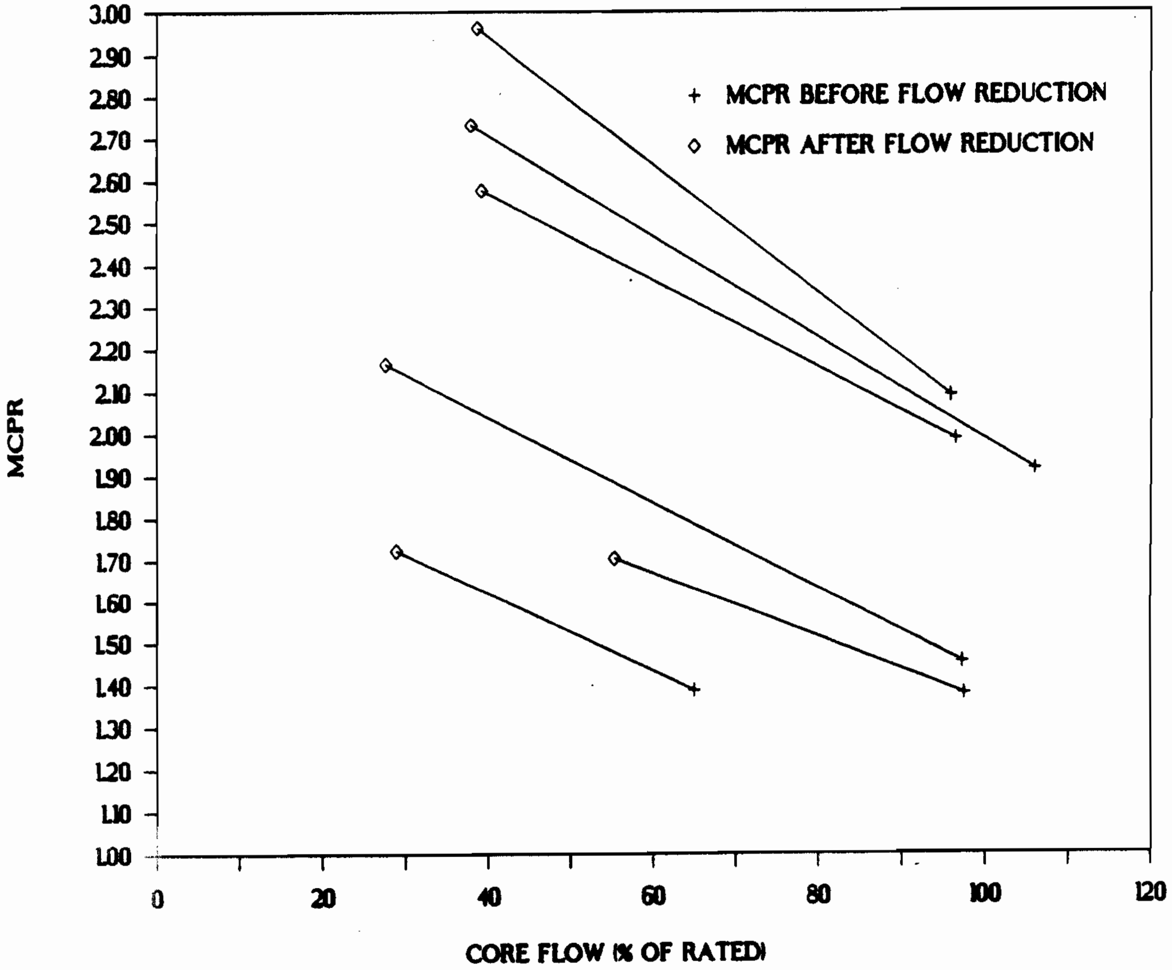

FIGURE 6-19. MCPR PERFORMANCE DURING FLOW REDUCTIONS - PROCESS COMPUTER DATA

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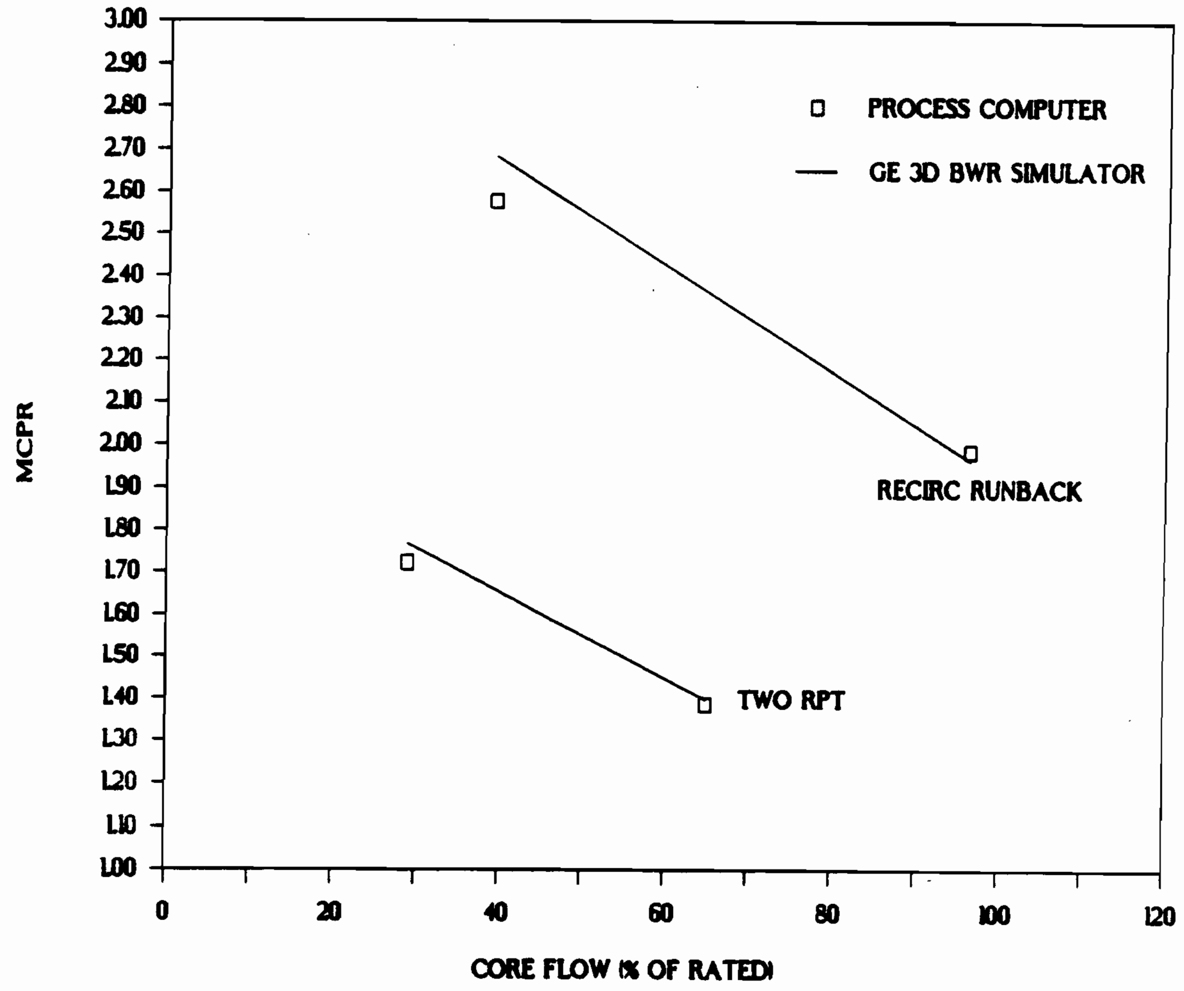

FIGURE 6-20. MCPR PERFORMANCE DURING FLOW REDUCTION - PROCESS COMPUTER VERSUS GE 3D BWR SIMULATOR RESULTS

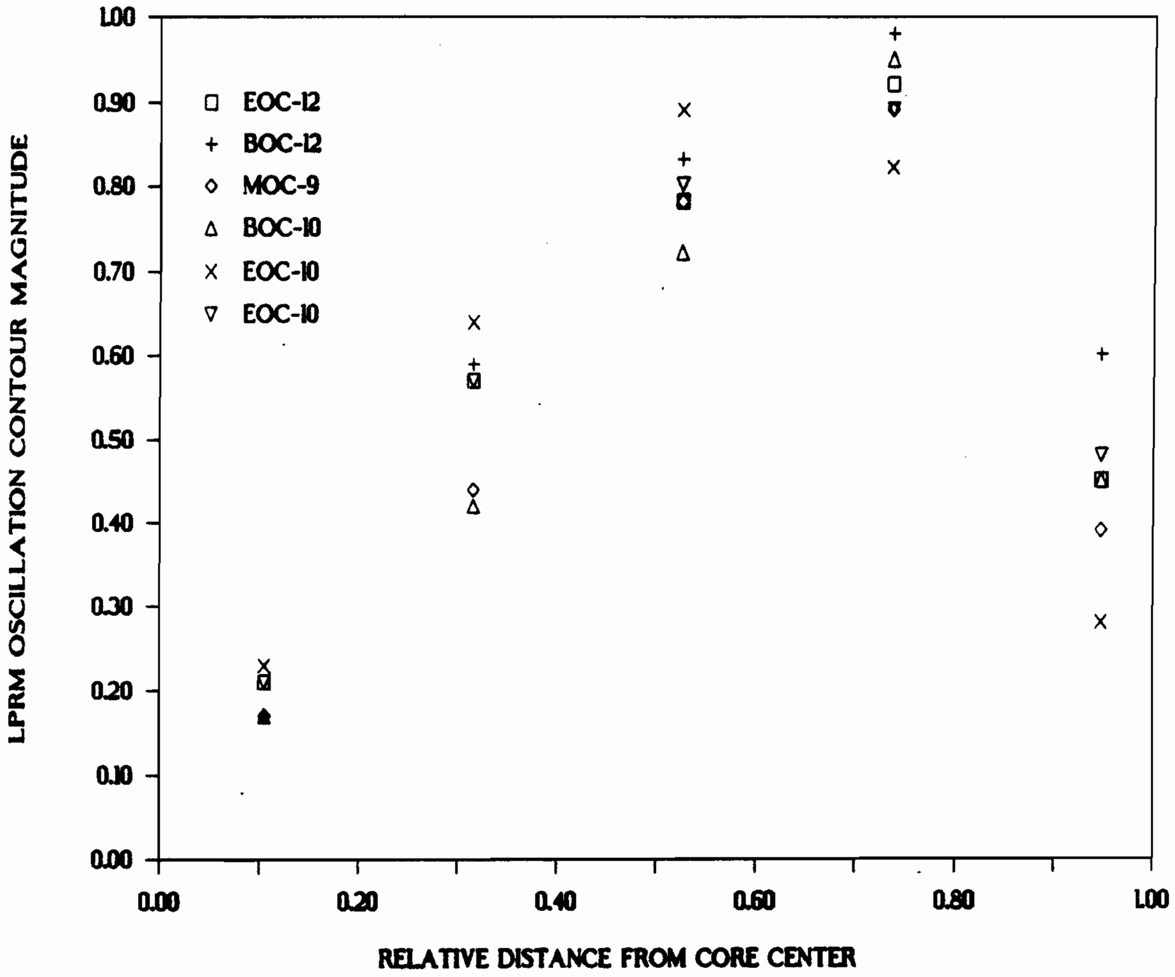

FIGURE 6-21. VARIATION IN 560 BUNDLE CORE OSCILLATION CONTOURS

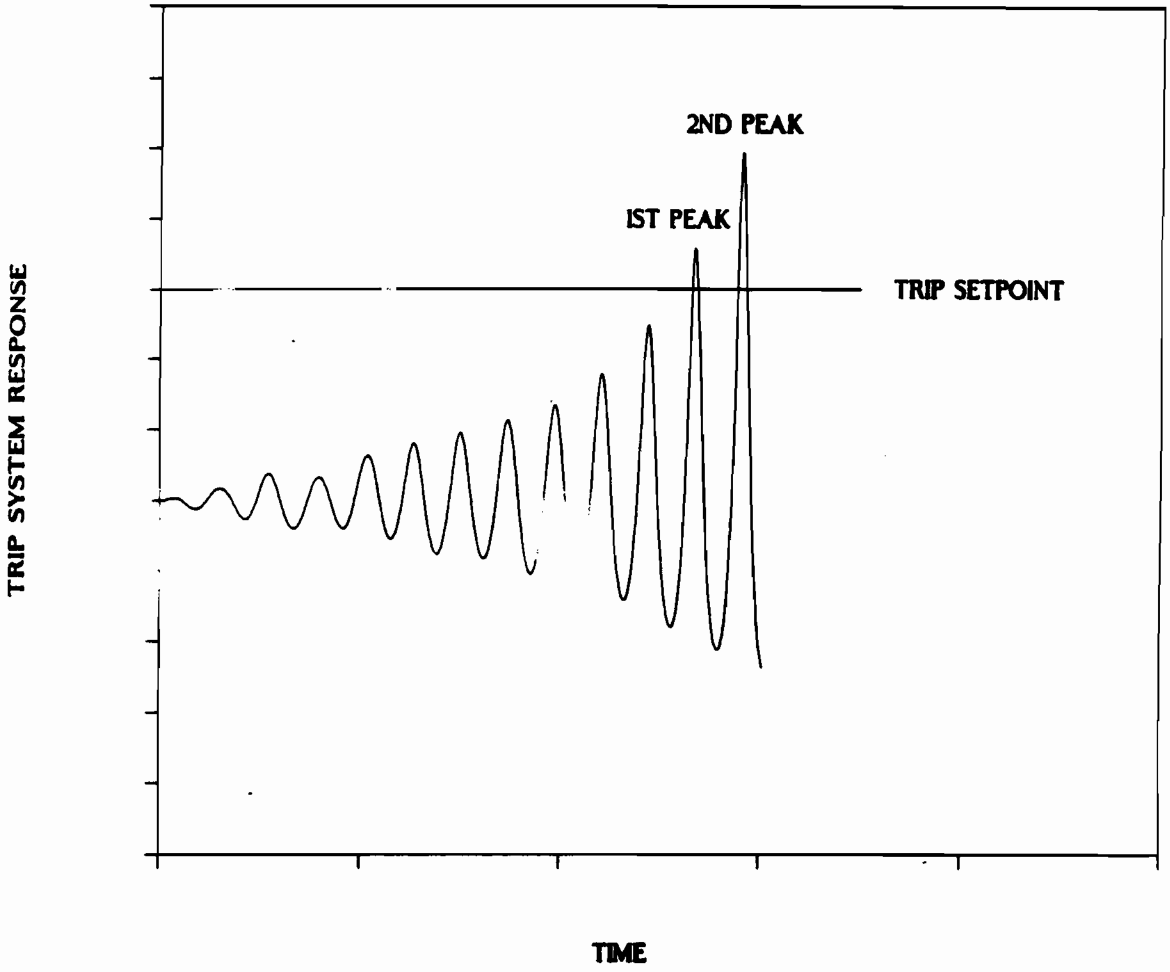

FIGURE 6-22. TRIP SYSTEM SETPOINT OVERSHOOT DURING OSCILLATIONS

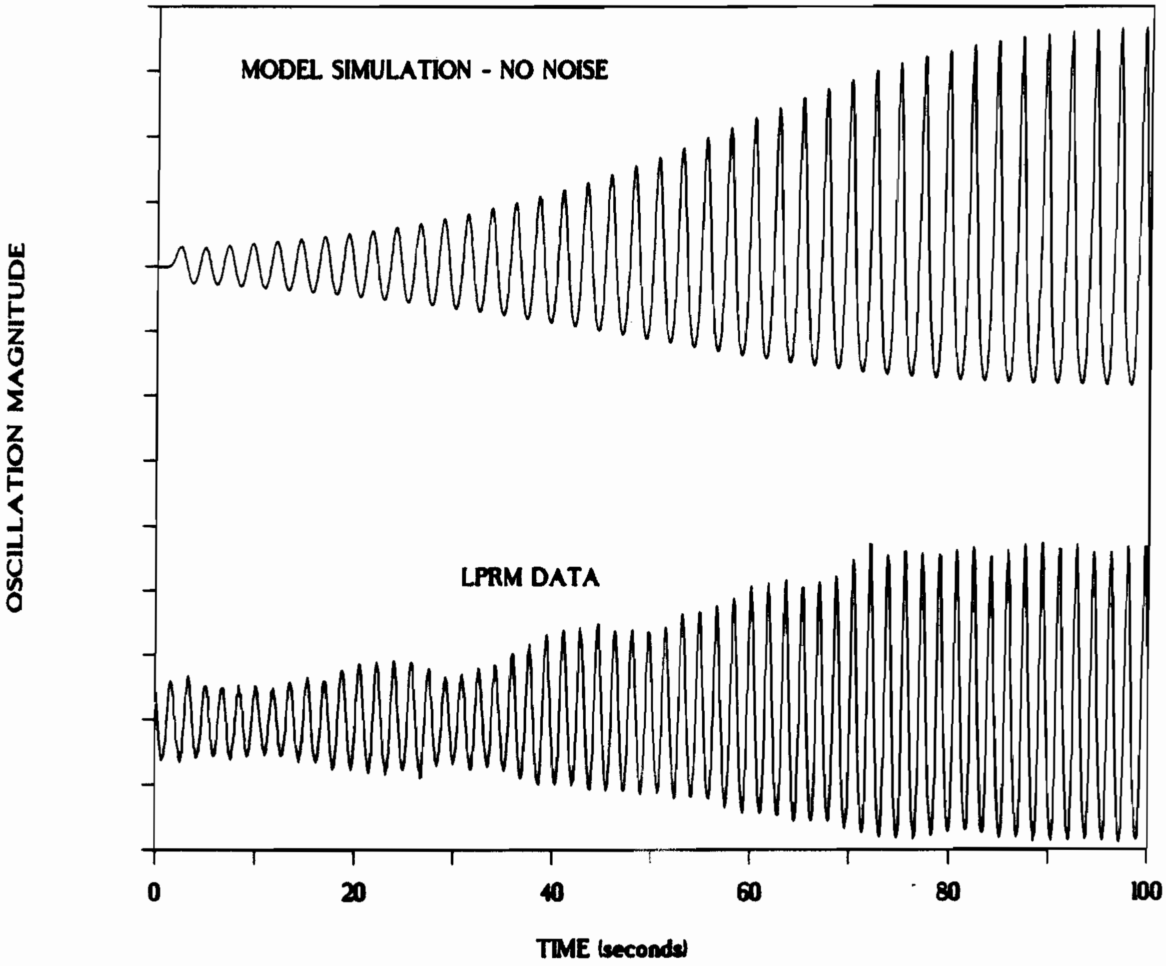

FIGURE 6-23. OSCILLATION GROWTH RATE - PLANT DATA VERSUS SIMULATED OSCILLATIONS WITHOUT NOISE

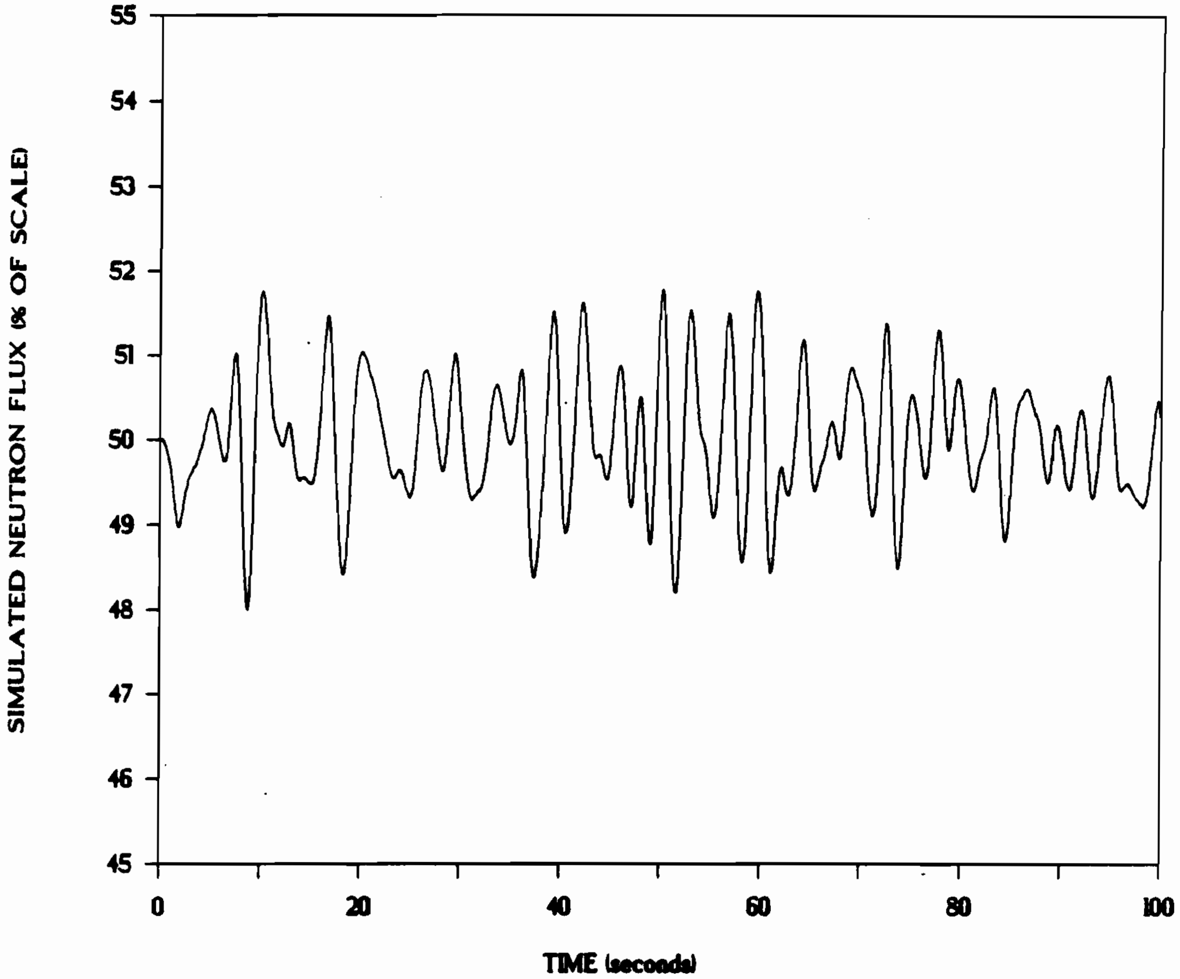

FIGURE 6-24. SIMULATED NOISE DATA - DECAY RATIO = 0.48

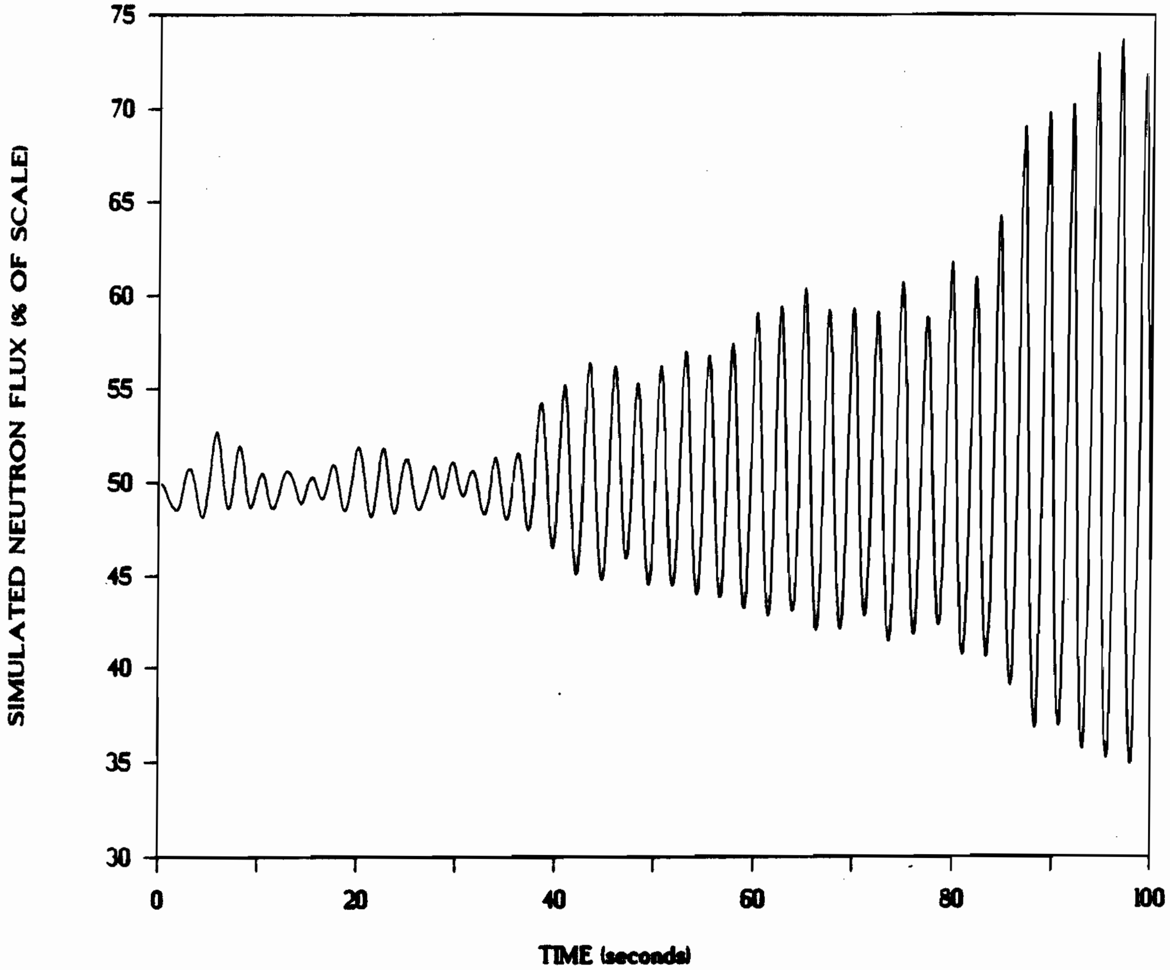

FIGURE 6-25. SIMULATED OSCILLATION SCENARIO - GROWTH RATE = 1.05

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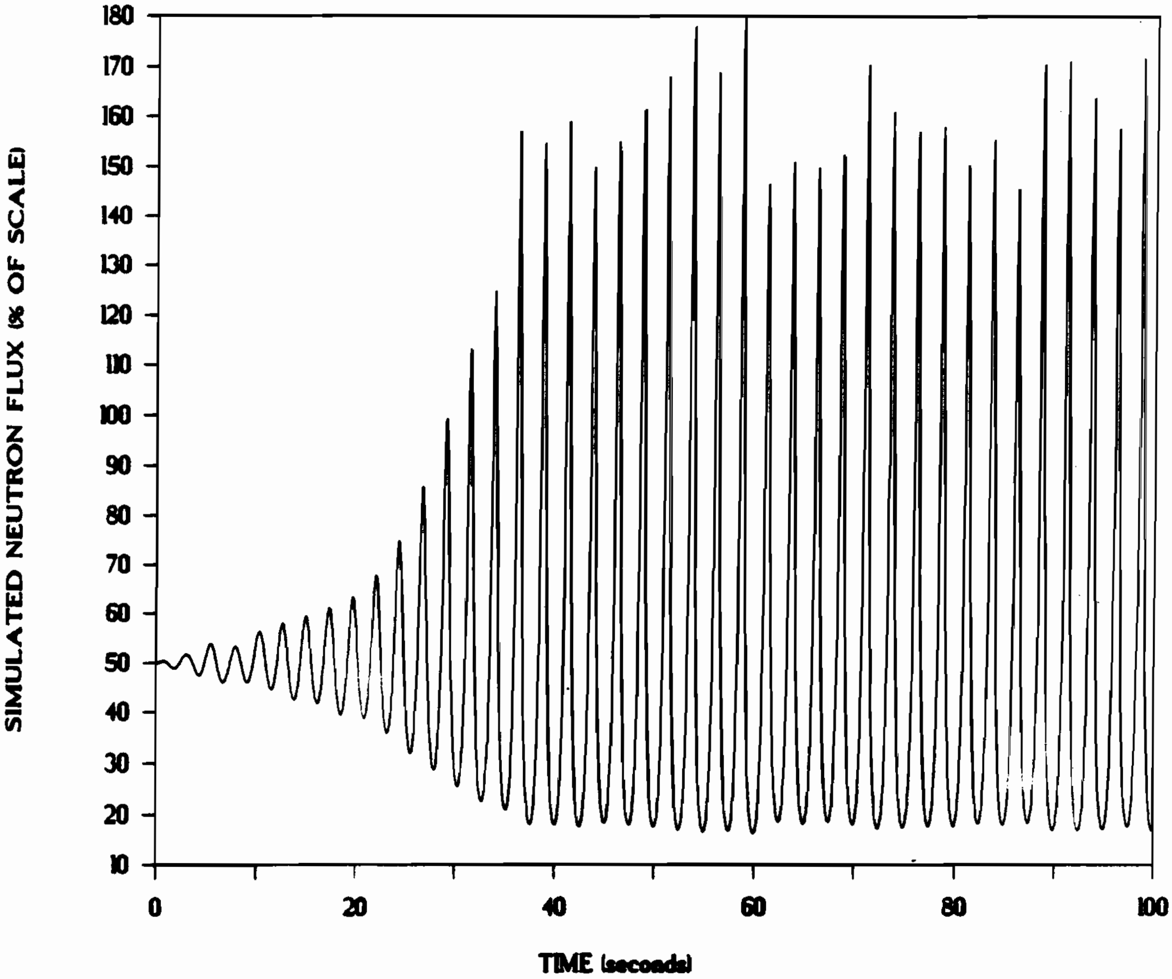

FIGURE 6-26. SIMULATED OSCILLATION SCENARIO - GROWTH RATE = 1.30

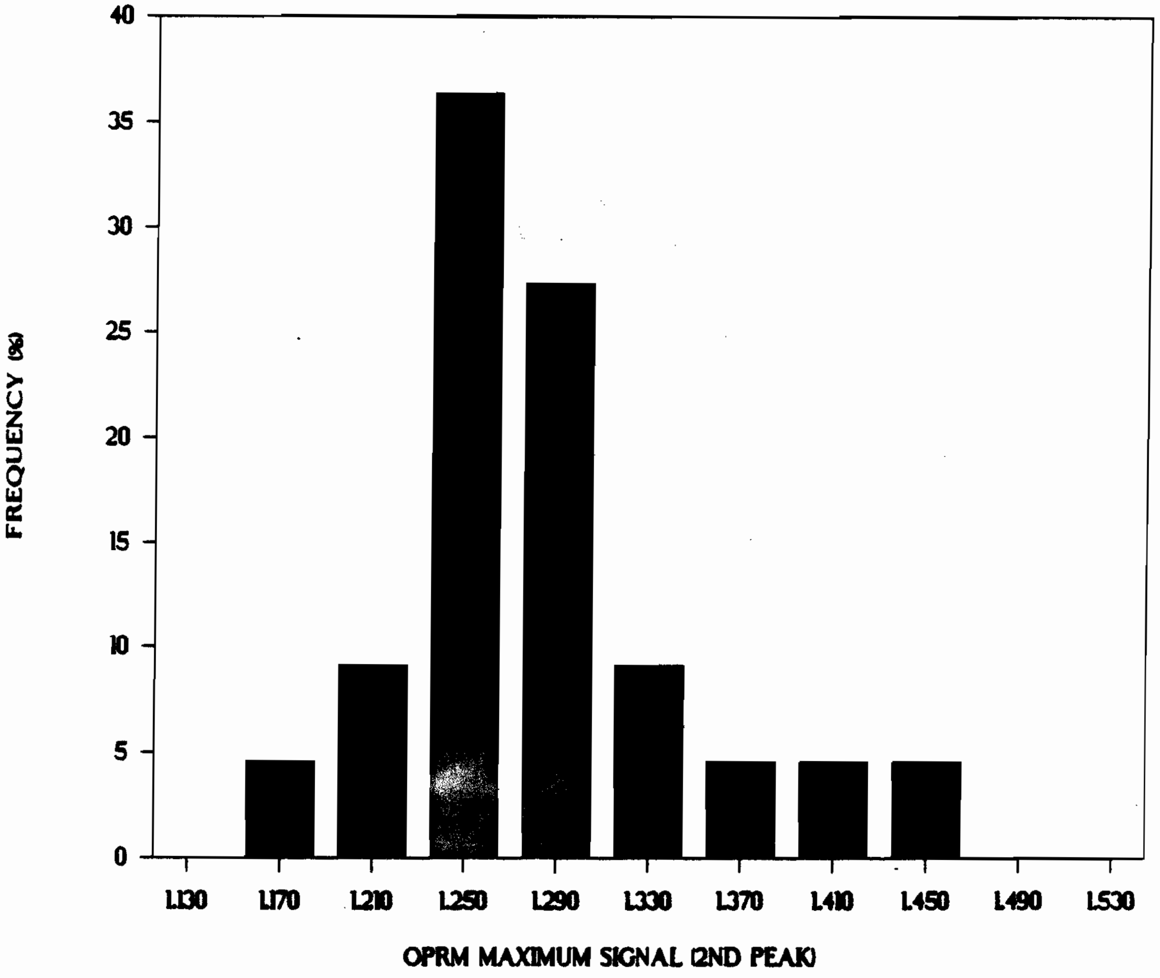

FIGURE 6-27. EXAMPLE SETPOINT OVERSHOOT DISTRIBUTION

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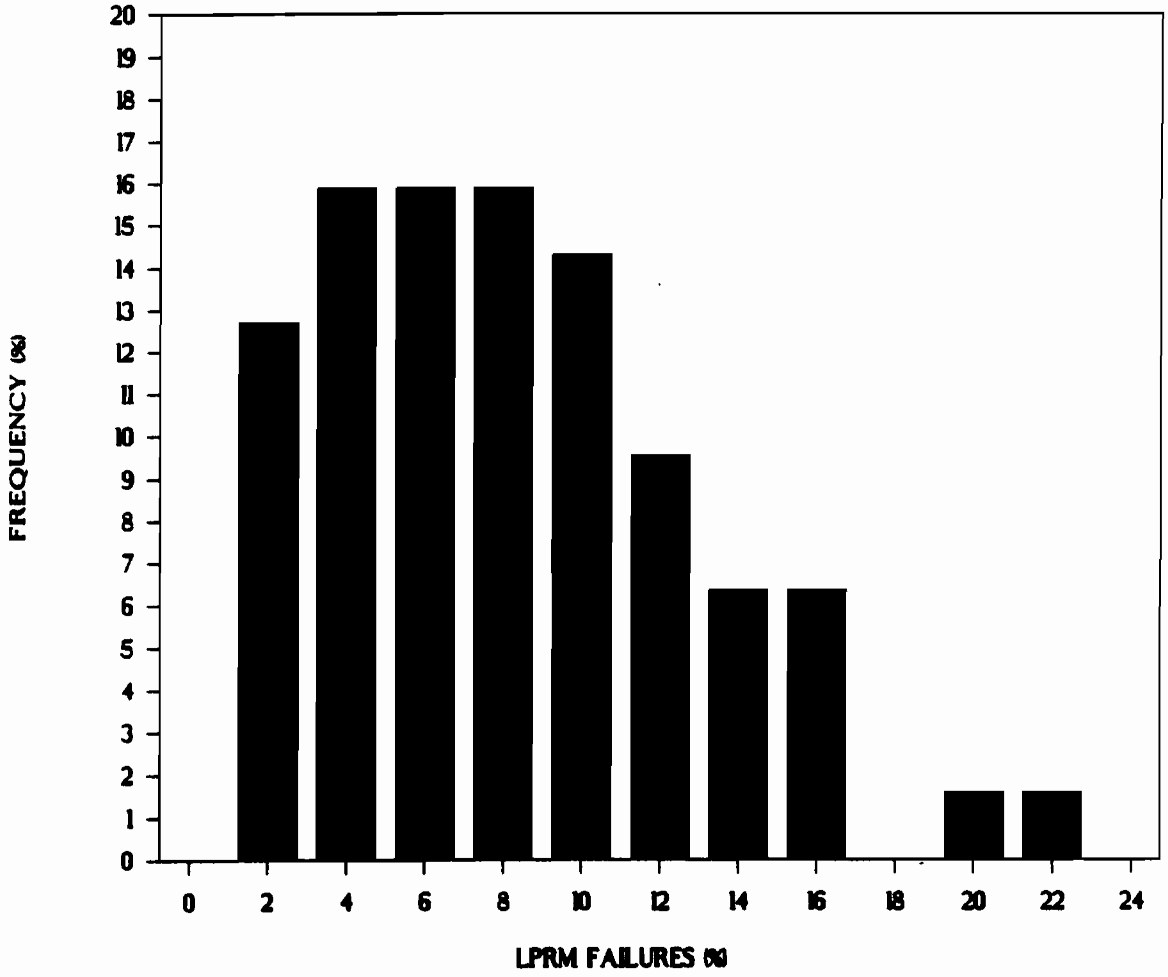
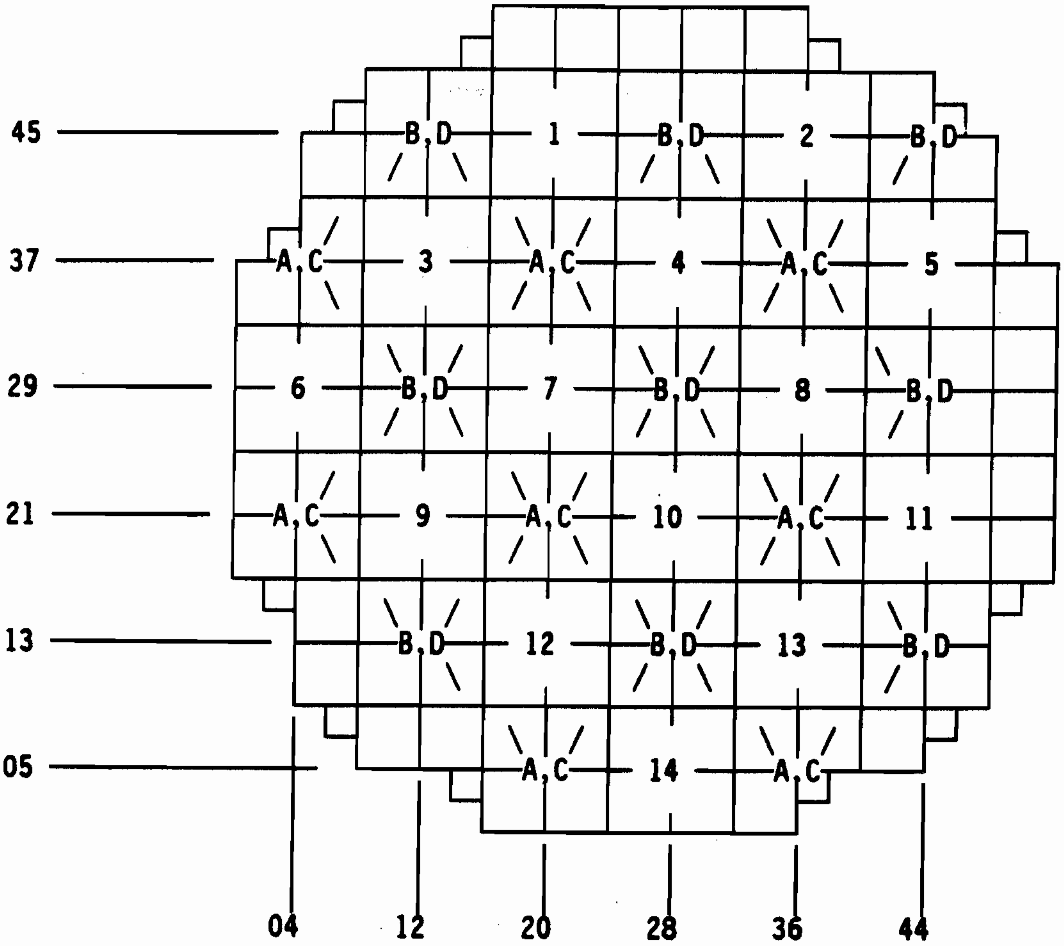


FIGURE 6-28. LPRM FAILURE RATE DATA



x,y
/ \
x,y n x,y
\ /
x,y

n = OPRM cell number

x,y = LPRMs assigned to OPRM-A1 channel (other LPRMs in string assigned to OPRM-A2 channel)

FIGURE 6-29. 560 BUNDLE LPRM ASSIGNMENTS TO OPRM A1(A2)

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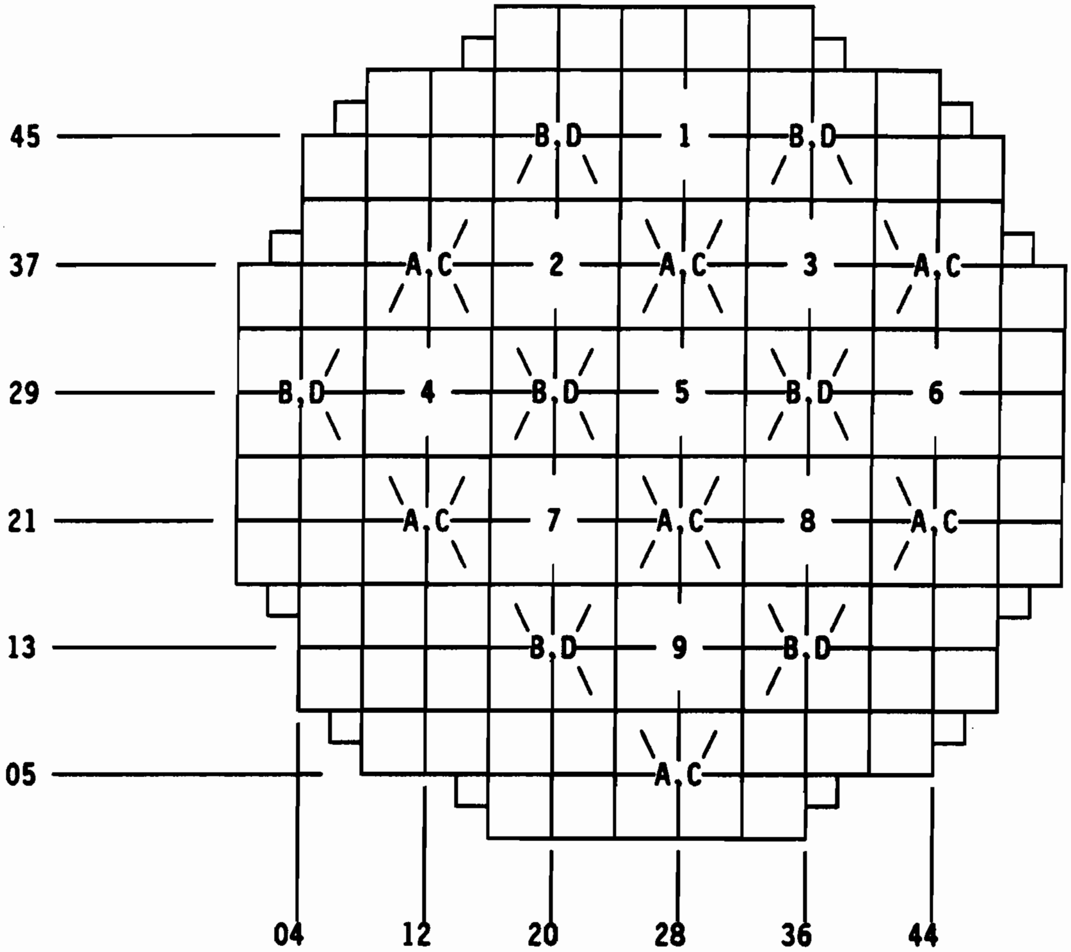

```
       x,y
     /     \
  x,y   n   x,y
     \     /
       x,y
```

n = OPRM cell number

x,y = LPRMs assigned to OPRM-B1 channel (other LPRMs in string assigned to OPRM-B2 channel)

FIGURE 6-30. 560 BUNDLE LPRM ASSIGNMENTS TO OPRM B1(B2)

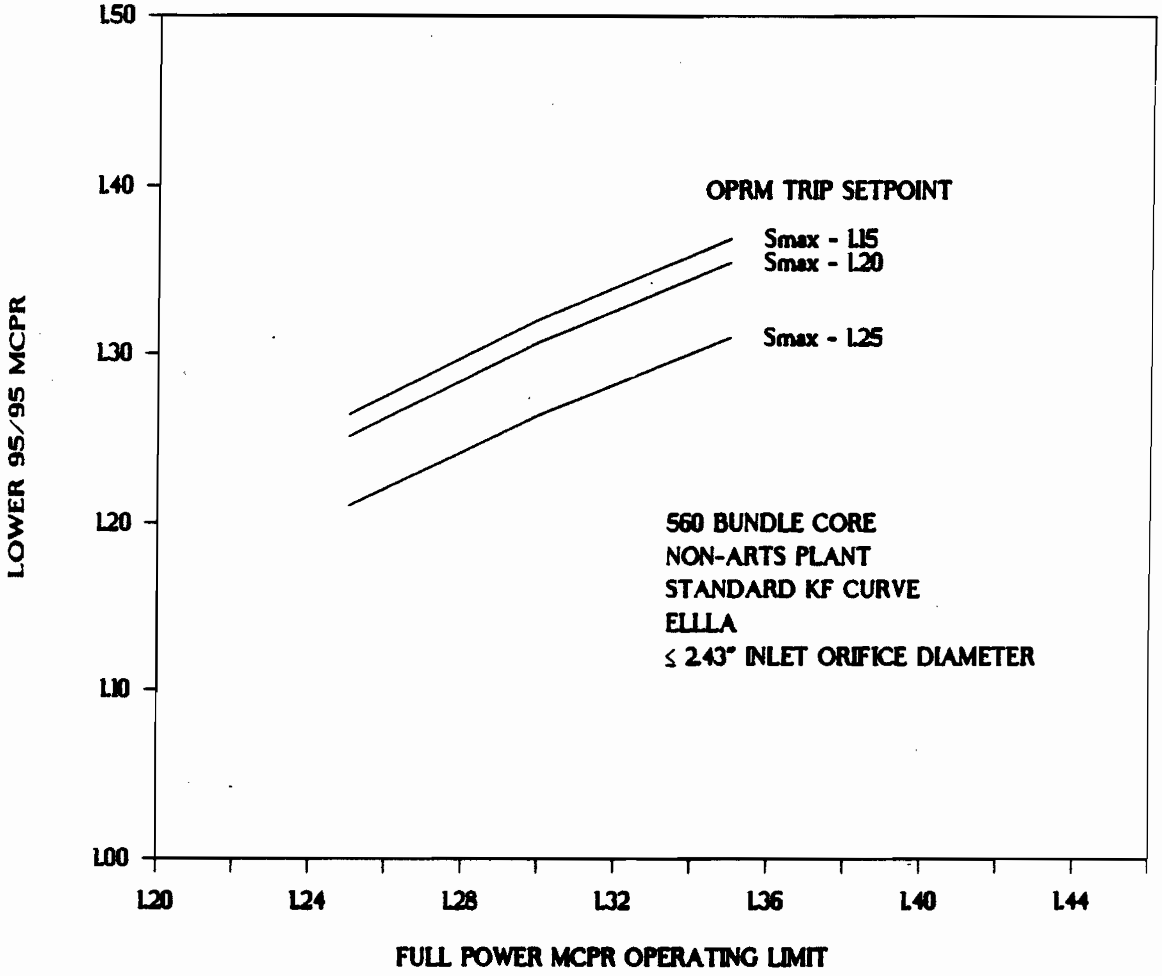

FIGURE 6-31. SAMPLE GENERIC ANALYSIS FORMAT

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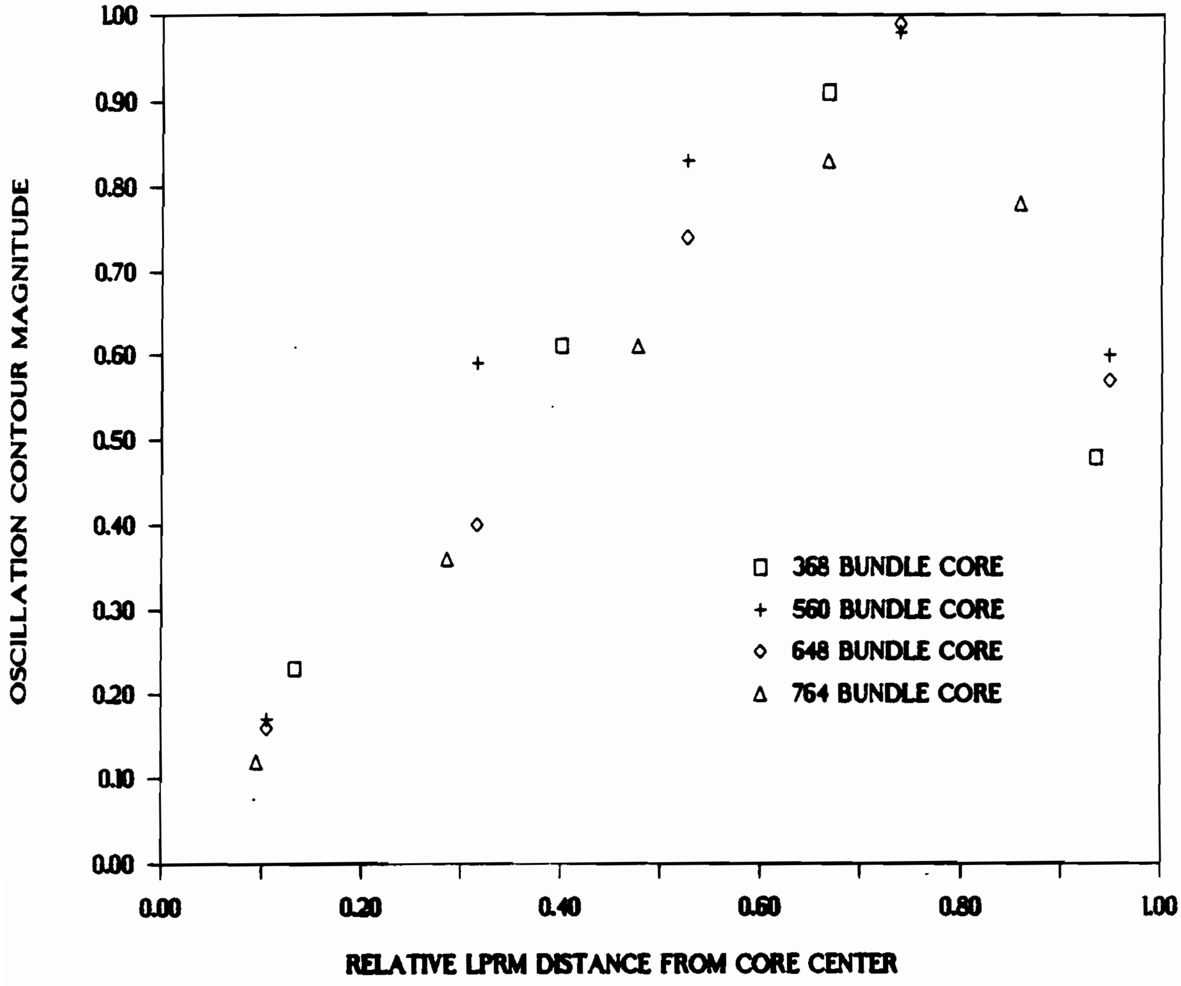

FIGURE 6-32. VARIATION OF OSCILLATION CONTOURS AS A FUNCTION OF CORE SIZE

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APPENDIX A

SOLUTION CONCEPTS

A.1 OPTION I-A - REGIONAL EXCLUSION

A.1.1 Solution Description

The objective of Option I-A is to assure compliance with GDC-12 by preventing the occurrence of instability. This is accomplished by preventing entry into power/flow regions where an instability may occur. The boundary of this excluded region is determined through application of the methodology described in Section 5.0 of the main body of this report. An example of an exclusion region is shown in Figure A-1. Upon entry into this exclusion region, the ASF trip function will cause the region to be exited.

For plants choosing to implement this solution, the existing flow-biased APRM trip circuit may be modified to provide the ASF. The new or modified ASF will be designed to the same requirements as the existing flow-biased scram function. The flow-biased APRM trip line may be modified as shown in the examples on Figure A-2. The modification may be implemented on existing circuit boards. There are also spare slots for an additional board on most APRM units. It is anticipated that for those plants with flow-biased neutron flux trips [i.e., no simulated thermal power monitor (STP)], the modified trip function will also be a neutron flux trip (no STP). For those plants with a STP, it will be retained in the modified trip function.

The ASF must assure that the system will insert a sufficient number of control rods to exit the region. One method is reactor trip. Other available systems such as Select Rod Insert (SRI) may also be used.

The flow-biased rod block signal is also modified in the same manner as the ASF signal, except that the intercept will be lower in power (estimated to be 5-10% lower). The offset between the trip setpoint and the rod block will depend upon whether the plant flow-biased circuitry includes a STP and the amount of instrument noise typically experienced by the plant at the associated power level. There is no stability design basis requirement associated with selecting this difference since the ASF trip setpoint bounds the region that is potentially susceptible to instability. An example of an exclusion region with an associated rod block is presented in Figure A-2.

The implementation of this solution differs depending upon whether the ASF is a reactor trip or SRI. When a reactor trip is the ASF, the existing flow-biased APRM trip and rod block circuits are modified to provide multiple intercept and slope capability. The applicable intercepts and slopes are then maintained in a manner similar to current practices. When SRI is the ASF, a separate flow-biased circuit is implemented to initiate SRI.

The associated flow-biased APRM rod block trip function can be accomplished in one of two ways. The first way is to modify the existing flow-biased APRM rod block function to utilize the existing trip signal output above a specified flow, and to utilize the output from a new parallel flow-biased APRM rod block circuit that has multiple intercept and slope capability below the specified flow. A second way is to modify the existing flow-biased APRM rod block circuit with multiple intercept and slope capability as if the ASF were reactor trip instead of SRI.

A.1.2 Licensing Approach

The enforcement of an exclusion region with an ASF that prevents oscillations is the basis for meeting GDC-12. Modification of the existing Reactor Protection System flow-biased APRM trip and rod block circuits to detect entry into the exclusion region provides a highly reliable and redundant means for monitoring plant operation relative to the exclusion boundary.

The capability of the ASF to cause the exclusion region to be exited will depend upon the number and distribution of control rods which are inserted. When the ASF is a reactor trip, the region will be quickly exited. When the ASF is SRI, the region will be exited provided a sufficient number and distribution of control rods are inserted. To ensure an adequate control rod configuration is achieved subsequent to SRI initiation, special requirements will be established. These requirements will address the variability of the impact control rod configuration has on power as a function of control rod pattern, dynamic xenon transients, reactor flow, reactor power and cycle average exposure. It is expected that such surveillance requirements may be met using 3-D nodal simulation techniques.

A.1.3 Methodology Application

The Option I-A concept utilizes the regional exclusion methodology of Section 5 of the main body of this report. This methodology establishes the boundary of a power/flow region where an instability may occur. The conservatism of the procedure used to define the exclusion boundary is confirmed by both steady state and event-based calculations.

A.1.4 Technical Specifications

Implementation of Option I-A with either reactor trip or SRI as the ASF will require modifications to existing Technical Specifications to identify setpoints, instrument operability and surveillance requirements. The following specifications are expected to be revised for implementation of Option I-A:

- Reactor Protection System Instrumentation Setpoints
- APRM Setpoints
- Reactor Protection System Instrumentation
- Control Rod Block Instrumentation
- Recirculation Loops

A.1.4.1 Reactor Protection System Instrumentation Setpoints

The RPS instrumentation Setpoints Specification will be modified if reactor trip is selected as the exclusion region ASF. The modification to existing Technical Specifications will identify setpoints for the multiple intercepts and slopes of the modified flow-biased APRM trip circuit while retaining current setpoints beyond the upper flow of the exclusion boundary. The modified specification will include a table similar to the following:

	Trip Setpoint	Allowable Value
(a) Flow Biased		
Slope 1 ($W > W1$)	$aW + y1$	$aW + y2$
Slope 2 ($W2 \leq W < W1$)	$bW + y3$	$bW + y4$
Slope 3 ($W3 \leq W < W2$)	$cW + y5$	$cW + y6$
Slope 4 ($W < W3$)	$dW + y7$	$dW + y8$
(b) High Flow Clamped	x1	x2

W = drive flow (% rated)
W1,W2,W3 = drive flow slope change points (% rated)
a,b,c,d = setpoint slopes (%/%)
yi = setpoint intercepts (% of rated)
xi = clamped setpoints (% of rated)

A.1.4.2 APRM Setpoints

For some plants, the APRM setpoints specification requires that the flow-biased scram trip and rod block setpoints be adjusted by a factor "T". T is defined as the ratio of the fraction of rated thermal power (FRTP) to the core maximum fraction of limiting power density (CMFLPD). A similar adjustment is made for units using ANF reload fuel. The purpose of this specification is to ensure that these setpoints are adjusted to account for differences in peaking from the peaking assumed in the calculation of core thermal limits. Since the new flow-biased setpoints protect against the onset of instability, T-Factors or their equivalent are not applicable to the setpoints for the lower trip function.

A.1.4.3 Reactor Protection System Instrumentation

The RPS instrumentation specification addresses requirements for each RPS trip function. These requirements are (1) operational condition for which function is required, (2) minimum number of operable channels per trip system, (3) LCO action statement, (4) response time and (5) surveillance requirements.

When reactor trip is the ASF, there are no additional requirements for the RPS instrumentation.

The RPS instrumentation is also used when the option for using SRI as the ASF is selected. There are no changes in the requirements of the RPS instrumentation specifications. In addition to the RPS instrumentation, there will be instrumentation utilized in achieving SRI actuation. This instrumentation will meet the same requirements for the operational condition for which the function is required and for surveillances. Requirements for the minimum number of operable channels per trip system, LCO action statements and response times will be established consistent with the configuration of the SRI instrumentation.

A.1.4.4 Control Rod Block Instrumentation Setpoints

Consistent with the philosophy of the Improved Technical Specifications developed by the BWROG (Reference 12), the rod block function associated with the flow-biased trip need not be included in the Technical Specifications. There is no stability design basis requirement associated with the rod block and, therefore, the rod block function does not satisfy the necessary criteria for inclusion in the Technical Specifications. For those plants with Rod Block instrumentation Technical Specifications, modifications similar to the RPS instrumentation Setpoints of Section A.1.4.1 are made.

A.1.4.5 Recirculation Loops

The current specification addresses two loop operation, single loop operation, and operation in natural circulation. In addition, some plants provide direction to monitor neutron flux noise when operating at high power and low core flow conditions. It is proposed that the specification be modified to include the following requirements, and that plants delete the neutron flux noise monitoring requirements where they occur in existing Technical Specifications.

A map of the exclusion region as defined by the modified flow-biased APRM setpoints should be included (the exclusion region power/flow map may be placed in the plant's Core Operating Limits Report (COLR)). The area outside the exclusion region is an area of unrestricted operation. The unrestricted area, as the name implies, is an area where operation is allowed without restriction with respect to stability. The analyses performed to define the exclusion region boundary demonstrate adequate margin for steady state operation and for transients which initiate and remain within the unrestricted area. For transients which initiate within the unrestricted area and result in entry into the exclusion region, an instability is precluded by the initiation of the ASF.

A.1.5 Operator Guidance

Operator guidance will be provided to avoid the exclusion region (i.e., the ASF) during startup and shutdown. This guidance would direct the operator to increase core flow prior to exceeding a predetermined power level, which would be lower than the new rod block associated with the ASF setpoint of the exclusion region. The flow increase would result in a state where, given an increase in power to the target rod line, operation would remain outside the exclusion region.

Similarly, the operator would be instructed to insert control rods during a controlled shutdown prior to decreasing flow below a predetermined value. The rod insertions would continue to a point below the rod line which bounds the lower end of the exclusion region. The operator will also be given appropriate direction to respond to flow reduction and loss of feedwater heating events to avoid unnecessarily entering the exclusion region and initiating an ASF. Additional operator guidance will be provided to recover from SRI actuation for plants selecting SRI as the ASF. This guidance will include directions for reviewing the conditions leading to SRI initiation, confirmation that the exclusion region was entered and recovery instructions for returning to the pre-SRI rod pattern.

A.2 OPTION I-C - REGIONAL EXCLUSION WITH STABILITY APRM FLUX TRIP

A.2.1 Solution Description

The objective of Option I-C is to assure compliance with GDC-12 using a combination of prevention and detection and suppression. This is accomplished during normal operation by administratively controlling entry into an exclusion region identified as being susceptible to thermal-hydraulic oscillations. Intentional entry is only permitted for two speed recirculation system (flow control valve) plants during pump upshifts. If the exclusion region is entered as a result of an unexpected operational event the Stability APRM Flux Trip is armed and the operator is required to immediately exit the region. Should an oscillation occur while exiting the region the Stability APRM Flux Trip system detects and automatically initiates suppression of the oscillation through actuation of an ASF prior to exceeding the MCPR Safety Limit.

The exclusion region is determined using the methodology described in Section 5.0 of the main body of this report. This methodology has been demonstrated to be conservative for operating conditions resulting from both steady state and transient conditions. A representative boundary for the exclusion region is presented in Figure A-1.

For plants choosing to implement this solution the RPS will be modified to include the Stability APRM Flux Trip system. When the exclusion region is entered an alarm is actuated to alert the operator that the region has been entered and that the Stability APRM Flux Trip system is armed. When armed, each Stability APRM Flux Trip channel compares the unfiltered APRM signal with the Stability APRM Flux Trip setpoint (SFSP).

The SFSP consists of the simulated thermal power (STP) signal plus a delta of about 2-10%. The STP is a conditioned APRM signal which simulates the actual fuel cladding surface heat flux. The heat flux and the instantaneous neutron flux are different due to the thermal conductivity characteristics of the fuel. These characteristics result in a more slowly varying fuel thermal response relative to the instantaneous or unfiltered APRM neutron flux signal. The SFSP will be smaller than the neutron flux magnitude associated with oscillations large enough to violate the MCPR Safety Limit prior to suppression. When the instantaneous neutron flux signal exceeds the SFSP the ASF is actuated.

The ASF must assure that the system will insert a sufficient number of control rods to exit the region. One method is reactor trip. Other available systems such as SRI can be used if sufficient control rod worth is available to exit the exclusion region. The new or modified ASF will be designed to the same requirements as the existing flow-biased scram function. At a value of approximately 25-50% of the SFSP, an alarm function with a manual reset is provided. The exact value of the trip and alarm setpoints are determined as described in Section A.2.3. The qualitative relationships between the STP signal, the APRM flux noise, the SFSP, and the alarm setpoint are presented in Figure A-3.

The Stability APRM Flux Trip system is not capable of discriminating between true oscillations and other flux signals. If while operating in the exclusion region the instantaneous neutron flux exceeds the SFSP, an ASF is initiated by the RPS. It is often necessary during a pump upshift maneuver in a two speed recirculation system plant to operate in the exclusion region for short periods of time. During the actual pump upshift the instantaneous neutron flux increases quickly as power responds to the increased core flow. This increase could initiate a spurious Stability APRM Flux Trip system actuation in the absence of an oscillation.

To reduce the chance of spurious scrams during the pump upshift maneuver while in the exclusion region, the Stability APRM Flux Trip system has an option for bypass of the trip. When the bypass option is selected, administrative controls for manual detection and suppression of oscillations are used during the brief period of operation with the Stability APRM Flux Trip System bypassed.

A.2.2 Licensing Approach

The general licensing approach for Option I-C is to assure compliance with GDC-12 by preventing the occurrence of oscillations that could result in violation of the MCPR Safety Limit. This is primarily accomplished through preventing operation in a region of potential instability defined by application of the methodology of Section 5.0. Secondarily, if that region is unintentionally entered as a result of an unplanned operational event, this solution provides automatic detection and suppression of unacceptable oscillation levels through the Stability APRM Flux Trip and ASF.

The SFSP will be selected to provide margin to expected magnitudes of unfiltered APRM signal noise levels. The Stability APRM Flux Trip system with the selected SFSP will then be demonstrated to provide adequate margin to the MCPR Safety Limit during a postulated neutron flux oscillation using the methodology of Section 6.0. Analytical MCPR Safety Limit compliance will be demonstrated for all expected modes of GE BWR neutronic/thermal-hydraulic neutron flux oscillations (defined in Section 6.1).

The bypass trip function will allow FCV plants to operate in or very near the exclusion region for the purpose of performing pump upshifts. The bypass will be controlled at the control room main panel and will conform to Reg. Guide 1.47. With the trip function bypassed, the operators will be required to monitor available instrumentation to ensure that instabilities are detected and suppressed in accordance with the guidelines provided in Bulletin 88-07, Supplement 1.

The capability of the ASF to reduce power to below the exclusion region will depend upon the number and distribution of control rods which are inserted. When the ASF is a reactor trip, the region will be quickly exited. When the ASF is Select Rod Insert (SRI), the region will be exited provided a sufficient number and distribution of control rods are inserted. To ensure an adequate control rod configuration is achieved subsequent to SRI initiation, special requirements will be established. These requirements will address the variability of control rod configurations, dynamic xenon transients, reactor flow, reactor power and cycle average exposure. It is expected that such surveillance requirements may be met using 3D nodal simulation techniques.

A.2.3 Methodology Application

The basic approach to establishing the SFSP is to first determine an acceptably low setpoint such that expected plant evolutions will not result in Stability APRM Flux Trip system actuation and then confirm that the setpoint provides adequate margin to the MCPR Safety Limit. Therefore, evaluation of plant operating data against potential Stability APRM Flux Trip system designs is a necessary step in the determination of the SFSP. Basic characteristics of oscillations are already known from test data and operating experience. Neutron flux signals generated by simplified point kinetics model (including the effects of random noise) and digitally recorded plant data during various maneuvers are analyzed to determine the margin to trip for expected plant maneuvers without oscillations.

The analytical methodology used to demonstrate that the SFSP provides margin to the MCPR Safety Limit is described in detail in Section 6.0. The methodology simulates LPRM and APRM responses to oscillations of various growth rates. These simulations explicitly account for delays associated with the trip system and ASF. Sections 6.2 and 6.3 detail how these delays and trip system setpoints are related to the MCPR performance of the limiting bundles, and how uncertainties are treated.

A.2.4 Technical Specifications

Implementation of Option I-C with either reactor trip or SRI as the ASF will require modifications to existing Technical Specifications to identify setpoints, instrument operability and surveillance requirements. The following specifications are reviewed to describe the expected revisions.

- Reactor Protection System Instrumentation Setpoints
- Reactor Protection System Instrumentation
- Recirculation Loops

A.2.4.1 Reactor Protection System Instrumentation Setpoints

The RPS Instrumentation Setpoints specification provides setpoints and allowable values for each RPS signal. A Stability APRM Flux Trip setpoint and the intercept and slope for the flow-biased description of the exclusion region must be added. For application to two speed recirculation system plants to accommodate the pump upshift maneuver, bypass provisions will also be specified. The modified specification will include a table similar to the following:

	Trip Setpoint	Allowable Value
Stability APRM Flux Trip		
(a) Trip System Bypass	aW + y1	aW + y2
(b) SFSP	STP + x1	STP + x2

W = drive flow (% rated)
a = bypass setpoint slope (%/%)
y1,y2 = bypass setpoint intercepts (% of rated)
x1,x2 = setpoint delta (% of rated)

A.2.4.2 Reactor Protection System Instrumentation

The RPS Instrumentation specification addresses requirements for each RPS trip function. These requirements are (1) operational conditions for which function is required, (2) minimum number of operable channels per trip system, (3) LCO action statement, (4) response time, and (5) surveillance requirements. This specification will have to be modified to include requirements for the Stability APRM Flux Trip system. These requirements will be the same as those for the existing flow-biased trip but with a note indicating the applicable operational conditions and that the trip function may be bypassed under administrative controls. When reactor trip is the ASF there are no additional requirements for the RPS instrumentation specification.

When SRI is selected as the ASF, the instrumentation used to achieve SRI actuation will be required to meet the same operational conditions and surveillance requirements as the instrumentation used to achieve reactor trip. Requirements for the minimum number of operable channels per trip system, LCO action statements, and response times will be established consistent with the configuration of the SRI instrumentation. These requirements will enforce the need to avoid the exclusion region and to follow the ICAs in the event of inadvertent entry with the SRI function inoperable.

A.2.4.3 Recirculation Loops

The current specification addresses two loop operation, single loop operation and operation in natural circulation. In addition, some plants provide direction to monitor neutron flux noise when operating are high power and low core flow conditions. It is proposed that the specification be modified to include the following requirements, and that plants delete the neutron flux noise monitoring requirements where they occur in existing Technical Specifications.

A map of the exclusion region as defined by the modified flow-biased APRM setpoints should be included (the exclusion region power/flow map may be placed in the plant's COLR). The area outside the exclusion region is an area of unrestricted operation. The unrestricted area, as the name implies, is an area where operation is allowed without restriction with respect to instability. The analyses performed to define the exclusion region boundary demonstrate adequate margin for steady state operation and for transients which initiate and remain within the unrestricted area.

An LCO for this specification will be provided only for two speed recirculation system plants to allow unplanned entry for the purpose of performing a pump upshift maneuver. Action statements will direct immediate rod insertion or flow increase upon indication of instability with the ASF bypassed.

A.2.5 Operator Guidance

Operator guidance will be provided to avoid the exclusion region during startup and shutdown. This guidance will direct the operator to increase core flow prior to exceeding a predetermined power level, which would be lower than the rod line associated with the exclusion region (and Stability APRM Flux Trip system actuation). The flow increase would result in a state where, given an increase in power to the target rod line, operation would remain outside the exclusion region.

Similarly, the operator would be instructed to insert control rods during a controlled shutdown prior to decreasing flow below a predetermined value. The rod insertions would continue to a point below the rod line which bounds the lower end of the exclusion region. The operator will also be given appropriate direction to respond to flow reduction and loss of feedwater heating events to avoid entering the exclusion region.

Additional direction for responding to upset conditions, including alarm response, will be provided. For example, following a trip of both reactor pumps, the operator will be directed to reduce reactor power by control rod insertion to a point below the exclusion region before attempting to restart the recirculation pumps. In all cases of inadvertent entry into the exclusion region, the operator will be directed to take immediate action to exit the region a manner designed to minimize the impact on instantaneous neutron flux levels (e.g., limiting the rate of flow increases, prohibiting rod withdrawal).

Operators of plants with two-speed reactor recirculation systems will implement, as necessary, procedural control of the selection of the trip bypass feature. These controls will permit selection of the trip bypass feature while in or near the exclusion region only for the purpose of performing the pump upshift. In addition to limiting the time with the trip function bypassed, these controls will specify a manual actuation of the ASF upon indication of an instability. Guidance similar to that contained in NRC Bulletin 88-07, Supplement 1 for operation in Region C will be provided for operation in the exclusion region.

A.3 OPTION I-D REGIONAL EXCLUSION WITH FLOW-BIASED APRM NEUTRON FLUX SCRAM

A.3.1 Solution Description

The objective of Option I-D is to assure compliance with GDC-12. This is accomplished by providing an administrative boundary for normal operations around the region where an instability could be expected to occur. This region has the same basis as the exclusion region defined in Section A.1. During normal operations, the boundary of the exclusion region is administratively controlled and operation within the region is avoided. An example of an exclusion region is presented in Figure A-1. If an unexpected operational event results in an entry into the exclusion region, steps will be taken to exit the region immediately. However, should oscillations occur, they will be automatically detected and suppressed by the Flow-Biased APRM Neutron Flux scram. For BWRs with tight fuel inlet orificing, the probability of regional (out-of-phase) oscillations is very low and the expected mode of oscillation is a core-wide (in-phase) oscillation. In addition, plants with small diameter cores are also less likely to experience regional oscillations because of the strong preference of the fundamental mode of the neutronics. Calculations will be performed to confirm that for core-wide oscillations the Flow Biased APRM Neutron Flux scram system will automatically detect and suppress oscillations prior to exceeding the MCPR Safety Limit. Protection commensurate with the low probability of regional oscillations will also be demonstrated for the Flow Biased APRM Flux scram system.

Oscillations will be detected by the existing APRM System. The oscillations will be suppressed by a Flow-Biased APRM Neutron Flux scram system, with an example shown in Figure A-4. The trip is based on comparing the unfiltered APRM signal to a setpoint that varies as a function of core flow. This option will not use a Simulated Thermal Power Monitor for detection. The Flow Biased APRM Neutron Flux scram system is part of the Reactor Protection System (RPS) trip logic and uses the one-out-of-two-taken-twice logic. Therefore, a spurious signal on one channel will not initiate a trip.

An RPS channel trip is generated when the unfiltered APRM neutron flux exceeds the flow-biased setpoint. The rod block function (also shown in Figure

A-4) serves as an alarm function and is typically located 8% lower in power than the scram setpoint. LPRM upscale and downscale alarms also provide the operators with indications of possible instabilities.

The Flow-Biased APRM Neutron Flux scram line relative to the estimated exclusion region for a BWR/4 with tight inlet orificing is shown in Figure A-5, and illustrates the close proximity of the scram line to the region of potential instability. At the condition of least margin to an instability, natural circulation and the maximum rod line, the scram setpoint is only several percent above the condition.

A.3.2 Licensing Approach

The general licensing approach for Option I-D is to assure compliance with GDC-12 by preventing the occurrence of instability-related oscillations that could result in a violation of the MCPR Safety Limit. This is primarily accomplished through preventing operation in the region of potential instability as defined in Section A.1 for Option I-A. However, if that region is unintentionally entered as a result of an unplanned operational event, this solution provides automatic detection and suppression of unacceptable oscillations through the Flow-Biased APRM Neutron Flux trip input to the RPS.

A.3.3 Methodology Application

A.3.3.1 Exclusion Region Boundary

The Option I-D concept uses the regional exclusion methodology of Section 5.0 of the main body of this report. This methodology establishes the boundary of a power/flow region in which an instability may occur. The conservatism of the procedure used to define the exclusion boundary has been confirmed by both steady state and event-based calculations (Sections 5.2.7 and 5.4). For Option I-D, intentional entry into the exclusion region during normal operations will be administratively prohibited.

To demonstrate the application of the methodology to a plant with tight fuel inlet orificing, Duane Arnold Cycle 10 was chosen. Duane Arnold currently is licensed for extended load line operation and has an uprated power density of 51 kW/l. Other key parameters which affect stability are summarized in Table A-1. Comparisons are also provided to other BWRs. Duane Arnold Cycle 10 contains predominantly GE 8x8 fuel. Core average Haling power shapes were generated at the EOC-10 using the GE 3D BWR Simulator. These power shapes are used in the radial and core average axial power distributions for the methodology described in Section 5.2. The full power Haling core average axial power shape which is used for the average channel power shapes when evaluating conditions at forced circulation flow rates is shown in Figure A-6. Also shown is the core average axial power shape that results from a flow reduction to natural circulation from the full power Haling condition. This axial power shape is used for the average channels when evaluating natural circulation conditions. The most negative void coefficient during the cycle is chosen for all analyses and occurs at EOC-2000 MWd/ST.

Calculations were performed at a high rod line, a lower rod line, and at natural circulation flow at the conditions defined in Figure A-7. The core and channel decay ratios for these conditions are summarized in Table A-2 and Figure A-8. The decay ratios are compared to the stability criteria (Section 5.1) in Figure A-8. Decay ratios less than the limit shown in Figure A-8 provide sufficient conservatism to potential instabilities. The intersection of the points which have calculated decay ratios equal to the stability criteria defines the exclusion region boundary. For the high rod line, the medium rod line, and natural circulation, interpolation is used between Points 1 and 2, 5 and 6, and 8 and 9, respectively. Based on these results, the exclusion region for Duane Arnold Cycle 10 is shown in Figure A-9.

The effect of the tight inlet orificing on channel decay ratios can be observed from the results in Figure A-8. This results in channel decay ratios which are well below 0.5 for all cases evaluated. This result will be discussed later in relation to expected modes of oscillation.

A.3.3.2 Expected Modes of Oscillation

The Flow-Biased APRM Neutron Flux scram will be demonstrated to be capable of responding to reasonably postulated modes of BWR stability-related oscillations. The stability design basis of the Flow-Biased APRM Neutron Flux scram system shall be to generate a trip signal during oscillations of sufficiently low amplitude to provide margin to the MCPR Safety Limit for expected modes of oscillations for cores with tight fuel inlet orificing. Tight fuel inlet orificing leads to a dominant core-wide mode, where the neutron flux in all fuel assemblies oscillates in phase. In addition, small diameter cores have very large eigenvalue separations for the azimuthal harmonics which reduces the probability of encountering regional oscillations. For core-wide oscillations, the Flow-Biased APRM Neutron Flux scram function provides direct detection and suppression prior to exceeding the MCPR Safety Limit (Section A.3.3.3). Plant data have also clearly demonstrated the ability of the APRMs to detect regional oscillations. Because the regional modes are unlikely to occur, more nominal assumptions are used in demonstrating compliance (Section A.3.3.3).

The expected modes of oscillation are dependent on the nuclear and thermal-hydraulic characteristics of the core. The existence of regional oscillations requires the excitation of the first-order azimuthal harmonic of the neutron flux. This may occur due to highly responsive channel hydraulic characteristics that are indicative of high channel decay ratios. The hydraulic response is necessary to provide sufficient reactivity to overcome the subcritical nature of the harmonic mode. Section 6.1 of the main body of this report discussed the basic characteristics of expected modes in BWRs. The following sections will discuss those characteristics of a specific class of plants which affect the potential modes of oscillation.

(1) <u>Channel Hydrodynamic Decay Ratio</u>

Section 5.0 of the main body of this report discusses the methodology and criteria used to predict whether oscillations will occur for a given set of inputs. Although the methodology concentrates on the calculation of core and channel decay ratios, the prediction of the potential for regional oscillations is implicitly included. Most frequency domain codes do not explicitly evaluate the decay ratio for the harmonic modes of oscillation and, therefore, a correlation is developed that relates the regional decay ratio to the core and channel decay ratios. Alternatively, other methods can be developed to estimate the regional decay ratio.

To estimate the regional decay ratio, the characteristics of a regional oscillation must be understood relative to the characteristics of channel and core stability. Channel stability involves the response of a single channel under constant plenum-to-plenum pressure drop conditions with no nuclear feedback. Core-wide stability involves the coupled response of all channels in the core through the void reactivity feedback. This total core response, similar to a core-wide pressure perturbation, results in oscillations in the total core inlet and exit flows. The oscillation in the exit flow is then transmitted through the recirculation loop and is coupled back to the core inlet flow. Axially, a spatial harmonic is excited in the neutron flux (Reference 13) that is the result of the density wave oscillation. The void reactivity feedback must be large enough to sustain the axial harmonic. A regional oscillation is similar to both single channel and core-wide oscillations. In a regional oscillation, not only is the axial harmonic excited, but also an azimuthal harmonic is excited in the neutron flux. This is the result of channel flows in one-half of the core oscillating ouf-of-phase with channel flows in the other half of the core. This provides a spatial reactivity feedback that can excite the azimuthal harmonic.

Although the azimuthal harmonic is a subcritical mode, the channel hydrodynamics are more responsive in the regional mode (similar to a single channel oscillation) where the plenum-to-plenum pressure drop remains essentially constant.

In general, the choice of a dominant mode is influenced by the inertial resistance of the recirculation loop which inhibits oscillatory flow, the responsiveness of channel flows under various boundary conditions, and the subcritical reactivity associated with the harmonic modes. The recirculation loop inertia works to stabilize the core-wide mode and impose constant pressure drop characteristics on the channels (leading to more responsive channel flows). More responsive channel flows under constant boundary conditions can provide additional reactivity feedback for the regional modes of oscillations. However, large eigenvalue separations of harmonic modes will tend to inhibit the excitation of the harmonic modes. For a regional mode of oscillation, the gain in channel flow responsiveness must be sufficient to overcome the subcritical nature of the neutronics. This section will concentrate on a discussion of the channel response as characterized by the channel decay ratio.

To separately study the potential for regional oscillations, a frequency domain analytical model was developed which includes a power feedback transfer function for individual channel hydrodynamic calculations. The channel hydraulics for this model are based on the GE one-dimensional transient model, ODYN (Reference 15). The one-dimensional liquid and conservation equations of mass and energy are linearized and the Laplace transform taken, such that small-perturbation techniques can be used. Perturbations in local flow variables (such as liquid and vapor velocities, void fraction) are then used in the momentum equation to calculate pressure drop perturbations. This form of the model is capable of calculating the standard channel hydrodynamic decay ratio.

As discussed above, regional oscillations are similar to single channel oscillations in that the plenum-to-plenum pressure drop remains essentially constant. However, a regional oscillation occurs with changes in neutron flux through the coupling with the void reactivity. This feedback term is not included with single channel models, since the heat flux is assumed to remain constant. The void reactivity feedback can be simulated by modeling the neutronics, specifically the harmonic modes. However, the feedback can also be estimated using results from the GE 3D BWR Simulator, which predicts the change in neutron flux for a given change in moderator density. The neutron flux change is a direct result of changes in the local moderator density, for the case of localized perturbations. For regional oscillations, this is a good assumption, since the fundamental mode is not significantly perturbed.

To account for the change in neutron flux (or heat generation rate within the fuel), a power feedback term is included in the channel model and is defined as

$$\delta P_k = (\delta P/\delta U)_k * \delta U_k \tag{A-1}$$

where

k = Axial node
P_k = Nodal power (heat generation rate),
U_k = Nodal water density
δ = Perturbation

For the channel hydrodynamic model, perturbations in channel flow will result in changes in coolant density, which, in turn, will cause changes in the two-phase pressure drop. This effect is fed back to the channel flow through the constraint that the total pressure drop must remain constant. Therefore, changes in moderator density are explicitly calculated in the channel model. To approximate the regional oscillation case, the effect of this change in moderator density must be fed back to the hydraulics model through the power feedback term of Equation A-1. Since the change in nodal heat generation rate occurs almost instantaneously following a change in local moderator density, the ($\delta P/\delta U$) term can be treated as a simple gain in the regional model with no phase lag. Since the feedback term will be applied separately at each axial node, the axial phase lag associated with the density wave oscillation will be explicitly included. Also, the nodal heat generation rate change is first applied to the fuel heat transfer model to correctly account for the gain and phase lag introduced by heat conduction through the fuel, gap, and cladding. Therefore, including the power feedback term of Equation A-1 approximately models the physical phenomena during a regional oscillation.

The more difficult task is to determine an appropriate representation of the ($\delta P/\delta U$) term in Equation A-1. Because of the nearly instantaneous change in neutron flux with moderator density changes, a quasi-steady-state assumption is used to estimate ($\delta P/\delta U$). The GE 3D BWR Simulator is used to establish steady-state conditions at the specific point to be analyzed. The steady-state condition is then perturbed by changing the inlet flow for a group of channels that would be expected to oscillate in phase during a regional oscillation. The perturbation is small enough that the fundamental mode reactivity is not changed. The total core power is held constant and the perturbed power distribution and moderator density are calculated. For the channels with perturbed inlet flow, the change in nodal power and change in moderator density are explicitly calculated by the Simulator at each axial node such that $(\delta P/\delta U)_k$ can be determined.

Sensitivity studies were performed to determine an appropriate inlet flow perturbation and number of bundles to be perturbed. In general, the results are insensitive for inlet flow perturbations of 1% to 10%. Also, as the number of bundles perturbed increases, the resulting change in nodal power reaches a plateau such that perturbations in additional bundles will not increase the relative bundle power increases. This suggests that for a regional oscillation, a relatively small group of bundles in a local region provides the majority of the reactivity feedback necessary to sustain the oscillations.

The regional feedback model was compared to stability data for several known regional oscillations. For Caorso Cycle 2 stability tests, tests at KRB-B, and initial cycle testing at Leibstadt, the above procedure was followed to estimate $(\delta P/\delta U)_k$ for the hot and average channels. In all cases, the pure channel hydrodynamic decay ratios (no power feedback) for the hot channels were less than 1.0. When the power feedback term was included, the hot channels were predicted to have "regional" decay ratios greater than 1.0 for conditions of known regional oscillations. Also, the average channels were predicted to have "regional" decay ratios close to 1.0 ($\geq$ 0.9). In general, the channel decay ratios increased by 0.3 when the power feedback term was included. Additional sensitivity studies were performed to determine the sensitivity of the results to conditions of varying core decay ratios.

For conditions with increasing core decay ratio, the change in channel decay ratio increased. Also, as the channel decay ratio increased, the relative changes in individual channel decay ratio increased. This is expected, since the channels with higher decay ratios are more responsive and have a larger change in moderator density during an oscillation. For a constant power feedback coefficient ($\delta P/\delta U$), this would result in more feedback to the hydraulics with a resulting increase in decay ratio.

Based on the results of the qualification cases and additional sensitivity studies, a map of the core versus channel decay ratios that would result in a "regional" decay ratio of greater than or equal to 1.0 was constructed. These results are summarized in Figure A-10, where a bounding curve has been included which encompasses all the results. For conditions outside this region, regional decay ratios would be predicted to be less than 1.0. The results in Figure A-10 were used along with other qualifications to generate the stability criteria shown in Figure A-11. Two core-wide oscillations that have been observed in GE BWRs are also plotted in Figure A-11 relative to the stability criteria. The two cases included are for the Vermont Yankee Cycle 8 limit cycle condition and the LaSalle-2 instability event. These results demonstrate the relatively low channel decay ratios calculated during core-wide oscillations.

Based on the results in Figures A-10 and A-11, for low channel decay ratios (< 0.5), even core decay ratios near 1.0 are predicted to result in a "regional" decay ratio less than 1.0. Physically, the channel decay ratio is a measure of the responsiveness of the channel flow. For a regional oscillation, this is very important in providing the extra feedback to sustain the oscillations. However, for very stable channels, even under constant plenum-to-plenum pressure drop conditions, sufficient flow oscillations are not available to sustain the oscillations. The core and channel decay ratios for a plant with tight fuel inlet orificing (Duane Arnold, Cycle 10) are summarized in Figure A-8. These results are based on the procedure of Section 5.2, which is specifically designed to provide a conservative estimate of the decay ratios. Even for these conservative conditions, considerable margin is maintained to the conditions predicted to result in regional oscillations. For conditions that result in exceeding the stability criteria of Figure A-11, the core decay ratios are from 0.8 to

1.0, with channel decay ratios of less than 0.4, resulting in a predicted core-wide mode.

An additional calculation was performed at the intersection of the 110% rod line and natural circulation (Table A-2, Point 10). This point is well within the defined exclusion region and, therefore, operator actions would result in minimizing the time at this condition. Even for this condition, the channel decay ratio calculated using the conservative procedure of Section 5.2 is less than 0.4. This condition would again be predicted to result in core-wide oscillations.

(2) Eigenvalue Separation for Small Diameter BWRs

The steady-state neutron flux in a BWR is analogous to the solution of the standard wave equation which involves eigenfunctions with unique properties which make them useful in transient and stability analysis. The eigenfunctions form a complete set and therefore, any function within the proper domain may be expanded in a linear combination of the eigenfunctions. In the modal synthesis method (Reference 12), the time-dependent neutron flux is expanded in terms of steady-state eigenfunctions with time-dependent coefficients. The fundamental mode is the eigenfunction with the largest eigenvalue and represents the steady-state solution to the neutron diffusion equation. The higher order modes, referred to as the harmonic modes, possess eigenvalues which are smaller than the eigenvalue of the fundamental. This difference in eigenvalues is commonly referred to as the eigenvalue separation of a harmonic and is a measure of the separation between the fundamental and harmonic mode.

At steady-state critical conditions, the eigenvalue of the fundamental is equal to 1.0 (critical) and, therefore, all harmonic modes must be subcritical (i.e., eigenvalues < 1.0). Subcritical modes will decay in time and are therefore not present at steady-state conditions. For a subcritical mode to be sustained, sufficient spatial reactivity feedback must be provided to overcome the eigenvalue separation. The best known type of spatial reactivity feedback associated with the harmonics is the result of changing xenon concentrations. For BWR stability, the existence of density wave oscillations in the channels provides another type of spatial reactivity feedback that is capable of exciting the axial harmonics in the neutron flux. In addition, thermal-hydraulic oscillations in which channel inlet flows oscillate out-of-phase (e.g., inlet flow is increasing in one-half of the core while decreasing in the other half) are also capable of providing the spatial reactivity necessary to excite the radial and azimuthal harmonics (referred to as regional oscillations).

The existence of a sustained density wave oscillation in a BWR requires excitation of at least the first-order axial harmonic. The neutron flux at four axial locations in the core during a regional instability, as measured by the Local Power Range Monitors (LPRM), is shown in Figure A-12 along with the average neutron flux oscillation. The axial phase lag observed in the neutron flux oscillation is the result of the density wave oscillation and is related to the void transit time through the channel. When the normalized axial neutron flux distribution is examined as a function of time, relative to the steady-state distribution, the oscillating component of the axial harmonic can be observed, as shown in Figure A-13 for the data from Figure A-12. The change in normalized axial neutron flux distribution at two times during an oscillation period is shown in Figure A-13, where the two points differ by half a period. The same excitation of the axial harmonic is also predicted by the TRAC-G code for a core-wide oscillation as shown in Figure A-14.

In the radial and azimuthal directions, the higher harmonics can be excited. The most common harmonic oscillation that has been observed in worldwide BWRs is the first-order side-by-side oscillation. This is the first harmonic in the azimuthal direction. The mode is called a first-order mode, since there is only one line of symmetry across which the neutron flux associated with the harmonic mode changes sign (+ to -). Higher order modes have even larger eigenvalue separations (more subcritical) than most first order harmonics. As discussed in Section 6.2.2, the GE 3D BWR Simulator has been modified to calculate the harmonic mode power distributions and eigenvalues. The method has been validated by solving a benchmark problem consisting of a homogeneous rectangular parallelepiped reactor. The analytical solution to this problem is known and is accurately predicted by the modified simulator.

The simulator has been used to predict the expected oscillation modes (harmonics) for a wide variety of core and fuel designs. The expected behavior of the eigenvalue separation as a function of core size has also been confirmed. As the core diameter is reduced, the buckling associated with the radial and azimuthal harmonics increases and therefore the eigenvalue separation also increases (i.e., more subcritical and therefore less likely to be sustained). The calculated variation of the eigenvalue separation for the axial and azimuthal harmonics as a function of the number of fuel assemblies (axial height constant) is shown in Figure A-15. These results are consistent with previous calculations of the harmonic modes performed during evaluations of Xenon instabilities in BWRs and PWRs.

From the results in Figure A-15, for core sizes less than 500 bundles, the axial harmonic is consistently predicted to be the lowest harmonic mode (i.e., highest eigenvalue). The azimuthal harmonic associated with regional oscillations is typically more than $2 in reactivity subcritical. For core sizes greater than 500 bundles, the eigenvalue separation of the axial and azimuthal harmonics are generally equal with no mode showing a specific preference. Therefore, for small cores (< 500 bundles) an additional factor that favors the core-wide oscillation mode is the large eigenvalue separation of the azimuthal mode. When coupled with the low channel decay ratios, the probability of regional oscillations is very low and, therefore, not an expected mode of oscillation for these plants.

A.3.3.3 Compliance to the MCPR Safety Limit

Section 6.0 of the main body of this report discusses the methodology used to evaluate the impact of oscillations on MCPR performance. The application of this methodology described in Section 6.3 is specific to those plants in which regional oscillations are the expected modes. The following sections discuss the application of the Section 6.0 methodology to those plants in which the core-wide mode is determined to be the expected mode of oscillation.

A.3.3.3.1 Core Wide Oscillations

Since the preferred mode of oscillation is assumed to be core-wide for cores with relatively "tight" inlet orifice diameters and small core size, this mode represents the design basis for Option I-D and the Flow Biased APRM Neutron Flux Trip System must be shown to provide an adequate level of protection against violating the MCPR Safety Limit. Therefore, analysis of the core-wide mode will follow the basic procedure outlined in Section 6.3 and use the same assumptions, except as stated below.

(1) Initial Conditions

For core-wide oscillations the assumptions and restrictions for initial conditions are the same as those of the generic methodology (Section 6.3.2.1). This includes initiation of the analysis with the plant operating at Technical Specification MCPR Operating Limits at the limiting rod line.

(2) Oscillation Contours

For a core-wide oscillation, the only mode of importance is the axial harmonic which is modeled directly as a higher order sinusoidal oscillation and the oscillation contour is constant for all LPRMs (i.e., same oscillation magnitude). The initial power distribution for a number of different points in the cycle is input to represent the variation in expected power distribution. This is the same as the approach used in the generic methodology (Section 6.3.2.2).

(3) Oscillation Growth Rate

The growth rate is the same as that assumed for the generic methodology (Section 6.3.2.2). The selected scenarios are evaluated against the APRM trip setpoint to determine the distribution of setpoint overshoots.

(4) Trip System Definition

For these analyses, the trip system is the Flow-Biased APRM Neutron Flux Trip. LPRMs will be assigned to their respective APRM channels and the trip setpoints will be determined for the appropriate final core flow during the oscillations.

(5) LPRM Failures

The LPRM failure assumptions are the same as those used in the generic methodology (Section 6.3.2.4).

(6) MCPR Performance

The treatment of MCPR variation with oscillation magnitude is the same as that used in the generic methodology (Section 6.3.2.5). However, since the change in CPR is a function of the oscillation mode, a correlation will be developed specifically for core-wide oscillations. An example of the difference in the CPR performance for a core-wide and regional oscillation with all other parameters held constant is shown in Figure A-16.

A.3.3.3.1.1 Example

The prototypical plant chosen for illustrating this analysis is the Duane Arnold Energy Center (DAEC), which is a 368 bundle, BWR/4, with 2.09 inch fuel inlet orifice diameter.

(1) Initial Conditions

In accordance with the methodology presented in the main report (Section 6.3.2.1), two initiating events are considered as precursors to the onset of thermal-hydraulically induced flux oscillations. The first is a trip of both recirculation pumps from full power conditions resulting in operation at natural circulation (approximately 30% rated flow). The second is a trip of both recirculation pumps from high power/low flow conditions indicative of startup operations. In accordance with the generic methodology, the first initiating event will be assumed to occur 95% of the time and the second, the remaining 5% of the time.

For DAEC, initiating events were considered along two rod lines. The first is the 110% rod line, which is characteristic of operation in the extended operating domain. The second is the 100% rod line, which results in lower powers at natural circulation conditions and therefore requires larger oscillations to initiate a trip. The final power at natural circulation is based on a rod line which is conservative in the sense that it predicts powers at natural circulation conditions which are further away from the APRM trip setpoint than might be encountered during expected operation.

The MCPRs prior to the two initiating events were taken from the DAEC Technical Specifications. For rated power operation, the initial MCPR is 1.20, and for operation at high power/low flow during startup, the initial MCPR is 1.43. The MCPR increase due to flow coastdown along the given rod line was determined by use of the generic methodology.

(2) Oscillation Contours

The oscillation contour for core-wide oscillations is assumed constant throughout the core. The fundamental power distribution is based on a set of DAEC specific calculations at the conditions defined in Table A-3.

(3) Oscillation Growth Rate

In accordance with the generic methodology (Section 6.3.2.2), a range of growth rates was used to determine the distribution of first and second peak overshoots. For DAEC, the second peak distribution is chosen because of the Technical Specification scram insertion times (Figure A-17). For these oscillations, it is assumed that the period of the oscillation is two seconds. This value is consistent with observed oscillations in GE BWRs.

(4) Trip System Definition

A trip system definition consistent with the DAEC Flow-Biased APRM Neutron Flux Trip System is used. The standard single RPS channel failure is also assumed.

(5) LPRM Failures

The LPRM failure statistics used in the generic methodology are used for these analyses.

(6) MCPR Performance

A fit of CPR change as a function of oscillation magnitude which was based on a large core with "loose" inlet orifices (2.43 inch diameter) during core-wide oscillations (Figure A-16) was used in the example. It is postulated that the change in MCPR with oscillation magnitude is less severe for a plant like DAEC with "tight" inlet orifices and a more appropriate correlation will be used in final setpoint analyses.

(7) Results

The predicted MCPRs for both of the rod lines are shown in Table A-4.

A.3.3.3.2 Regional Oscillations

Since regional oscillations are unlikely in plants for which Option I-D is applicable, nominal assumptions will be made for the analysis of these oscillations. The behavior of the plant with respect to thermal limits will be characterized by expected values.

(1) Initial Conditions

For regional oscillations under Option I-D, the assumptions and restrictions are the same as those of the generic methodology (Section 6.3.2.1). However, instead of assuming the reactor begins at Technical

Specification MCPR limits, plant operating data will be used to define expected values of initial MCPR for full power and startup conditions. In addition, the final power at natural circulation will be based on a nominal rod line.

(2) Oscillation Contours

The approach is the same as for the generic methodology (Section 6.3.2.2).

(3) Oscillation Growth Rate

It is assumed that the growth rate is sufficiently slow that there is no significant overshoot. This is different than the generic methodology (Section 6.3.2.2). In general, the APRM response during a regional oscillation does not increase as fast as independent LPRM responses and, therefore, the overshoot is expected to be negligible. In addition, since regional oscillations are not expected to occur, a low growth rate is an appropriate assumption.

(4) Trip System Definition

For these analyses the trip system is the Flow-Biased APRM Neutron Flux Trip System. All APRM channels are assumed to be operational and no failures are assumed during the event. RPS failures are not common and in general result in more conservative conditions (i.e., channel trip).

(5) LPRM Failures

The number of failed LPRMs is the same as that used in the generic methodology (Section 6.3.2.4).

(6) MCPR Performance

The treatment of MCPR variation with oscillation magnitude is the same as that used in the generic methodology (Section 6.3.2.5). However, a correlation will be specifically generated for the expected response of plants with tight fuel inlet orifices to properly account for the expected performance of the more stable channels.

A.3.3.3.2.1 Example

As was the case for core-wide oscillations, DAEC will be used for the analysis of regional oscillations.

(1) <u>Initial Conditions</u>

The initial conditions are the same as those used in the core-wide analysis with the following exceptions. Oscillations are most likely to occur at the intersection of the highest rod line and natural circulation flow and, therefore, analyses are only performed for the 110% rod line. The second is the use of anticipated MCPR values prior to the initiating event rather than Technical Specification limits. For DAEC, based on Cycle 10 data, the expected initial MCPR at rated power is 1.28. At startup conditions, an initial MCPR of 1.89 is assumed.

(2) <u>Oscillation Contours</u>

As discussed in Section B.3.3.2, negligible overshoot is assumed and the maximum signal value is equivalent to the trip setpoint.

(3) <u>Trip System Definition</u>

A trip system consistent with the DAEC Flow-Biased APRM Neutron Flux Trip System is used. It is assumed that all the channels are functional. The trip setpoint at natural circulation is 62% of rated.

(4) <u>LPRM Failures</u>

The LPRM failure statistics used in the generic methodology were used.

(5) MCPR Performance

The MCPR performance during oscillations is based on Curve 1 of Figure 6-11, which was generated for a regional oscillation in a large BWR with loose inlet orificing (2.43 inch diameter).

(6) Results

The predicted MCPRs for the maximum rod line are shown in Table A-5.

A.3.3.4 Sensitivity Studies

In Section A.3.3.3.1 examples were shown for a prototypical plant (DAEC). Since MCPR at full power may be expected to vary from plant to plant (and indeed from cycle to cycle for a given plant), a sensitivity study was performed to quantify the effect of variations in initial MCPR. The evaluations assumed regional oscillations occurred, similar to the results discussed in Section A.3.3.3.2.1.

Results were obtained for initial full power MCPRs from 1.28 to 1.48 to study the variation in final MCPR. For the two cases with MCPR of 1.38 and 1.48, an initial MCPR value of 2.209 was used for the low flow pre-event point. This value was used since it is more characteristic of a core with a full power MCPR in the 1.38 to 1.48 range. Operation along the 110% rod line was used for this analysis. The results from this study are shown in Figure A-18. As expected, more margin is provided for operation at higher initial MCPRs.

A.3.4 Technical Specifications

This section describes the philosophy of changes to Technical Specifications required for Option I-D. In general, changes to the APRM scram setpoints for protection against oscillations are not expected to be required. An LCO will be provided for exiting the region following an unplanned entry. An example of an exclusion region is shown in Figure A-1.

A map of the exclusion region as described in Figure A-1 will be included. An LCO for this specification will be provided to permit unrestricted operation outside the exclusion region. Action statements directing control rod insertion or flow increase in the event of unplanned entry into the region will also be included.

A.3.5 Operator Guidance

Operator guidance will be provided to avoid the exclusion region during normal operation. This guidance will direct the operator to increase core flow prior to exceeding a predetermined power level, which will be lower than the rod line associated with the setpoint of the exclusion region. The flow increase will result in a state where, given an increase in power to the target rod line, operation will remain outside the exclusion region. Similarly, the operator will be instructed to insert control rods during a controlled shutdown prior to decreasing flow below a predetermined value. The rod insertions will continue to a point below the rod line which bounds the lower end of the exclusion region. The operator will also be given appropriate direction to respond to flow reduction and LOFH events to avoid entering the exclusion region.

Additional direction for responding to upset conditions will be provided. For example, following a trip of both reactor recirculation pumps, the operator will be directed to reduce reactor power by control rod insertion to a point below the exclusion region before attempting to restart the recirculation pumps. In all cases of inadvertent entry into the exclusion region, the operator will be directed to take action to exit the region in a manner designed to minimize the impact on unfiltered neutron flux levels (e.g., limiting rate-of-flow increases, and prohibiting rod withdrawal within the exclusion region).

A.3.6 Operator Guidance

Operator guidance will be provided to avoid the exclusion region during startup and shutdown. This guidance will direct the operator to increase core flow prior to exceeding a predetermined power level, which would be lower than the rod line associated with the exclusion region (and Stability APRM Flux Trip system actuation). The flow increase would result in a state where, given an increase in power to the target rod line, operation would remain outside the exclusion region. Similarly, the operator would be instructed to insert control rods during a controlled shutdown prior to decreasing flow below a predetermined value. The rod insertions would continue to a point below the rod line which bounds the lower end of the exclusion region. The operator will also be given appropriate direction to respond to flow reduction and loss of feedwater heating events to avoid entering the exclusion region.

Additional direction for responding to upset conditions, including alarm response, will be provided. For example, following a trip of both reactor pumps, the operator will be directed to reduce reactor power by control rod insertion to a point below the exclusion region before attempting to restart the recirculation pumps. In all cases of inadvertent entry into the exclusion region, the operator will be directed to take immediate action to exit the region a manner designed to minimize the impact on instantaneous neutron flux levels (e.g., limiting the rate of flow increases, prohibiting rod withdrawal).

A.4 OPTION III - LPRM BASED OSCILLATION POWER RANGE MONITOR

A.4.1 System Description

A.4.1.1 General Description

The Oscillation Power Range Monitor (OPRM) is a microprocessor-based monitoring and protection system which will detect a thermal-hydraulic instability, provide an alarm on small oscillation magnitudes, and initiate an Automatic Suppression Function (ASF) to suppress an oscillation prior to exceeding safety limits.

The OPRM is a Class 1E protection system which monitors the output of all installed Local Power Range Monitor (LPRM) detectors; the OPRM conforms to all applicable requirements of IEEE-279-1971. Four OPRM channels are provided. The OPRM channels provide inputs to trip logics which initiate an ASF.

The OPRM function is in parallel with, and independent of, the existing Class 1E and non-1E functions of the Power Range Neutron Monitoring (PRM) System. The OPRM does not affect the design bases for the existing PRM components, their calibration, or their separation schemes.

Each OPRM channel takes amplified LPRM signals from available locations in the PRM panels. These LPRM signals are grouped together such that the resulting OPRM response provides adequate coverage of expected oscillation modes. Each OPRM channel is comprised of a relatively large number of OPRM cells, where an OPRM cell represents a combination of several LPRMs (one to eight) in geometrically adjacent areas of the core. LPRM signals may be input to more than one OPRM cell within an OPRM channel. Individual LPRM signals may also be used directly to provide a more sensitive response to oscillations. The selection of the number of LPRMs (one to eight) combined and monitored as one input to the trip function involves a number of tradeoffs best evaluated during the detailed hardware design phase.

Each OPRM channel consists of a Class 1E microprocessor unit, either in a stand alone cabinet or as a subcomponent to the PRM cabinet. Several microprocessor-based control units are commercially available for nuclear safety related service. Some modules, such as GE's NUMAC and Westinghouse's Eagle 21, have been reviewed by the NRC; SERs have been issued for their safety related use in other applications. As is typical for these types of devices, each OPRM channel performs safety-related and non safety-related functions, and interfaces with other 1E and non-1E systems, for which external and internal system isolation and fault tolerance per IEEE-384 are required. The software will be qualified in accordance with Regulatory Guide 1.152 requirements.

The above hardware descriptions, in conjunction with the sample detection algorithm defined in Appendix B, constitute the OPRM solution.

A.4.1.2 OPRM Suppression Functions

The OPRM function provides inputs to an ASF whose purpose is to suppress oscillations prior to exceeding the MCPR Safety Limit. The OPRM function would be installed and maintained as a Reactor Protection System (RPS) protection function or could provide inputs for a Select Rod Insert (SRI) function.

The SRI function, as presently used, is intended to reduce core power to less than the turbine bypass capacity, so that the unit avoids a scram during a load rejection event. The same function may be used to reduce power to suppress oscillations without a full scram. Verification of this function's capability to effectively terminate a thermal-hydraulic instability event is required for those plants which are considering this option.

For implementation as a RPS function, the four OPRM channels provide inputs, one for each RPS trip channel, for a one-out-of-two-taken-twice actuation trip logic. Reactor scram will therefore occur when at least one OPRM trip channel in each RPS trip system is in the tripped condition. For a Solid State RPS logic plant, the four OPRM channels provide inputs to the two-out-of-four channel to divisional logics (any two channels in trip will result in a reactor scram). For implementation as a SRI function, appropriate trip logic will be chosen to ensure high reliability of the ASF. For the purposes of this report, the OPRM channel assignments will be discussed relative to their assignments to a RPS function.

The instability trip function will not be used to initiate the Alternate Rod Insertion (ARI) system. The ARI trip function, installed per 10CFR50.62, is not required to provide an automatic scram function which is redundant and diverse to the instability trip function. ATWS/instability events have been shown to develop sufficiently slowly such that manual scram techniques, or manual ARI initiation, are sufficient to back up instability trip system failures. If the reactor becomes isolated from the main condenser, the ensuing transients provide the necessary ARI initiation from water level or reactor pressure signals.

A.4.1.3 LPRM to OPRM Assignments

The purpose of the OPRM design is to provide detection and suppression of expected oscillation modes in a BWR. This involves monitoring LPRMs throughout the core. Because the OPRM channels provide inputs to trip logics, appropriate channel redundancy and reliability are required. Additionally, the desire to avoid spurious actuations and allow for expected LPRM failures and bypasses must be incorporated into the system design. In general, all of these considerations were included in the original design of the Average Power Range Monitor (APRM) systems and therefore, where possible, the available LPRM assignment schemes between the APRM channels are used in the OPRM design. The following design decisions were made to satisfy the stated requirement:

Requirement	Design Feature
Detection of expected oscillation modes	All LPRMs (radially and axially) will be evaluated for providing input to the OPRMs. LPRM signals which are combined will be from geometrically adjacent areas.
Redundancy	Each LPRM string (four detectors) can provide input to at least two OPRM channels.

Requirement	Design Feature
Reliability Avoid spurious actuations Tolerant to LPRM bypass/failure	Up to eight LPRM signals will be combined to form the input for one OPRM "cell". This will minimize the possibility of a spurious actuation from a single LPRM. The response of any one OPRM cell can cause a trip of the associated OPRM channel.

Review of the LPRM to APRM assignments and separation schemes resulted in identification of three basic groups of plants; large cores (30 or more LPRM strings), small cores (20-24 LPRM strings) and the solid-state RPS design (Clinton BWR/6). The distribution of plants among the basic groups is shown in Table A-6. For the large cores, the LPRM to APRM assignments along with the use of unassigned LPRMs (Group A and B) provides a logical grouping of LPRMs into OPRM channels. LPRMs are assigned to OPRMs according to which APRM or unassigned LPRM group their input is provided. Each OPRM channel receives inputs from LPRMs which are assigned to either of two APRM channels or from LPRMs assigned to one APRM channel and LPRMs assigned to an LPRM group. These associations are shown in Table A-7. The four OPRM channels are designated as A, B, C and D, or when, referring to their association with RPS, it is more convenient to refer to the channels as A1, B1, A2, and B2, respectively.

The further combination of LPRM signals within an OPRM channel for the large core group also makes use of the natural distribution of LPRMs within the assigned channels. A basic diamond pattern was chosen to define the combinations of six to eight LPRMs within an OPRM channel, since the LPRM separation among the two RPS trip systems gives rise to this pattern. An example is shown in Figure A-19 of a diamond in which the LPRM strings at the four points of the diamond are in one RPS trip system and the LPRM string in the center of the diamond is in the other trip system. This LPRM association is known as an OPRM cell. The OPRM computes the response of the OPRM cell using two LPRM signals from each of the four LPRM strings at the corners of the diamond shown in Figure A-19. Where one of these corners falls on or outside the core periphery, the response is calculated using the remaining three LPRM strings. Where more than one corner falls on or outside the periphery, a cell is not defined.

The specific LPRM assignments to each OPRM cell are also shown in Figure A-19, where a pattern is established that is repeated throughout the core. The four LPRM signals in each string are split into two groups (A/C and B/D, where A is the bottom LPRM in the string) where one group is assigned to OPRM channel A1 and the other group is assigned to A2 (B1 and B2 in the other trip system). For a given row or column of LPRM strings in the same trip system, this assignment is repeated (i.e., A/C to A1 and B/D to A2). The pattern is then reversed for alternating rows and columns (A/C to A2 and B/D to A1). This ensures that, axially, the LPRMs are uniformly distributed among the OPRM channels.

An example of the OPRM cells in OPRM channel A1/A2 for a core with 43 LPRM strings (764 fuel bundles/185 control rods) is shown in Figure A-20. Note that the two LPRM inputs from any one LPRM string that input to the same OPRM channel are used by two, three or four OPRM cells. This provides a significant amount of cell overlap, providing reliable detection of oscillations occurring in relatively small core regions. The overlap that exists between the OPRM channels assigned to the two RPS trip systems is shown in Figure A-21. The remaining assignment of LPRMs to OPRMs (OPRM B1/B2) for a core with 43 LPRM strings is shown in Figure A-22. For the 764 bundle core, there are 16 OPRM cells for each RPS A channel and 18 OPRM cells for each RPS B channel, with each cell consisting of six or eight LPRM inputs.

For small cores, the smaller number of LPRM strings results in each LPRM being shared among the RPS trip systems in the APRM system. No LPRM is shared between redundant trip channels. A similar concept can be expanded to the small core OPRM design where each LPRM string provides LPRM signals to two OPRM channels (one from trip system A and one from B). The assignments are staggered as in the large core design, except that for the A channels the staggering is along diagonals and for the B channels along rows. An example of this assignment scheme for a 20 LPRM string core is shown in Figure A-23. The small core OPRM cell uses two LPRM signals from each of three selected LPRM strings, for six LPRM inputs each.

Alternatively for small cores, the LPRMs could be assigned to the OPRM channels with no sharing of LPRM signals between the two RPS trip systems or between redundant channels within a trip system. Each LPRM string would provide one LPRM input to each of the four OPRM channels. The axial distribution of these LPRMs between the OPRM channels would be uniform. Instead of a diamond pattern of assignments, the basic OPRM cell configuration would be that of a square, with each OPRM cell receiving four LPRM inputs. The square also provides a smaller geometrical spacing for combined LPRMs consistent with the smaller core size. For locations near the periphery where one corner of the square does not include an LPRM string, the OPRM cells would use the inputs from the remaining three LPRM strings. The basic assignments that would be used for this design are shown in Figure A-24. Final selection of the LPRM to OPRM assignments will be determined during the hardware design phase.

For the solid-state RPS design, each LPRM string provides one input to each of the four separate APRM channels. These APRM channels are then combined in a two-out-of-four, channel to divisional logic. This same separation could be maintained similar to the alternative small core OPRM assignment scheme, where each LPRM string would provide one input to each OPRM channel with four LPRMs combined in a cell. Because of the larger size of the solid state RPS plant (33 LPRM strings), this same separation scheme could be used with the diamond pattern of the large core group except that the center LPRM string would also provide an input to the OPRM cells for the diamond. This would result in a basic OPRM cell containing five LPRM signal inputs. Alternatively, the LPRM to OPRM assignments could be performed exactly as in the large core group. Final selection of the LPRM to OPRM assignments will be determined during the hardware design phase.

OPRM channel redundancy is evident from the LPRM assignments shown in Figures A-20, A-22, A-23 and A-24. Each LPRM string of four detectors feeds signals to at least two OPRM trip channels for complete regional redundancy within an RPS trip system. OPRMs associated with RPS trip systems A and B are essentially equal in sensitivity due to the OPRM cell overlap in the large cores, and the pattern of shared LPRMs in the small cores. Monitoring multiple axial locations in each LPRM string provides an assurance of reliability and, together with the overlap of multiple OPRM cells, allows tolerance of multiple bypassed LPRMs in any individual OPRM cell.

For any size unit, a single LPRM string may also be used to provide a more localized OPRM cell of one or two detectors. Such use of fewer detectors per cell (the limit becomes one detector per cell) results in a system more sensitive to regional oscillations, but also more susceptible to false trips due to LPRM noise or malfunction. Depending on owner-specific weighting of pros and cons, an OPRM system using, for example, two LPRMs per cell may be desirable. An example of such an application to a 764 bundle unit is shown in Figure A-25. Half of the LPRM strings are assigned to RPS A (shown in the figure) and the remainder to RPS B (not shown). The A and C level LPRMs in this example are combined to make one cell that is input either to RPS channel A1 or channel A2. The B and D level LPRMs are then similarly combined for input to RPS channel B1 or channel B2.

A.4.1.4 OPRM Trip and Alarm Functions

Each OPRM channel will perform a real time analysis of LPRM signal responses. For each cell, the OPRM will compute a response based on the assigned LPRM inputs. Determination of peak-to-average values of LPRMs or OPRM cells is used to evaluate the magnitude of oscillations. Time averaging of responses is used to provide a time dependent baseline for normalizing oscillation magnitudes. The signal sampling and computation frequency will be well above the expected thermal-hydraulic oscillation frequency, essentially producing a continuous and simultaneous measurement of all defined OPRM cells. Any individual OPRM cell which satisfies the conditions and criteria of the trip algorithm will be sufficient to produce the OPRM channel trip function.

A description of a sample OPRM algorithm is provided in Appendix B. Many forms of algorithms may be used to distinguish oscillations from noise or other plant occurrences. Algorithms use the known frequency of oscillations (i.e., 0.3 to 0.7 Hz) to aid in screening out other signal variations such as electrical spiking, 60 Hz noise, and reactor system and control system transients. Time delays for the channel trip introduced by the algorithm will be appropriately factored into the setpoint analyses as discussed in Section 6.3.

The OPRM alarm is designed to provide the operator with warning prior to a channel trip. This is accomplished using the same algorithm as discussed above for the channel trip with a lower setpoint.

A.4.1.5 OPRM Operating Bypasses

The OPRM will be operable in the power range of operation (i.e., Mode 1). However, historical data and operating experience have shown that the protective function is not required at low core power or at high core flow conditions. Because spurious actuation is always a concern for trip channels, it is appropriate to provide an operating bypass under conditions when the protective function is not required. LPRM signal noise at low power conditions and bistable core flow at high core flow conditions are examples of system inputs which may result in unnecessary trips if the OPRM is not bypassed.

The OPRM interfaces with the existing APRM Reactor Recirculation System Drive Flow Units, which are used for a high core flow system bypass. This bypass is removed under single loop operating conditions above the low power bypass setpoint.

The OPRM also interfaces with the APRM module outputs for a low power system bypass. As an alternative, the OPRM may directly compute core power from LPRM averages, with operator interface as necessary to calibrate the LPRM average to a plant heat balance.

Because this bypass is enabled by process conditions, the OPRM trip function becomes automatically functional given any plant operating transient of interest. These bypass functions are considered to be part of the Class 1E portion of the OPRM.

A.4.1.6 LPRM Bypasses

The OPRM communicates with the LPRM amplifier cards such that the OPRM can detect and account for bypassed LPRMs. The OPRM cell is considered to be active when the number of valid LPRM signals is greater than or equal to a number to be determined during the design phase, which may range from one (for the individual LPRM OPRM example) to three or four (for the eight LPRMs per OPRM cell design).

LPRM signals which do not exceed a minimum value may contain process or signal noise components which may affect the OPRM cell response. The OPRM algorithm may bypass LPRM signals which fall below system requirements, or may normalize the LPRM oscillation peak magnitude to a core wide average. The adjustments are automatically enabled or removed based on process conditions.

A.4.1.7 Operator Interface

No direct control interface is required for the safety-related OPRM trip function. However, the OPRM has a wide range of alarm, display, and other capabilities. The specific non-1E functions will be defined in the engineering development of the OPRM function, device, and software. No credit is taken for operator interface in achieving the system functional performance requirements.

A.4.2 Licensing Approach

A.4.2.1 Overview

A.4.2.1.1 GDC-12 Compliance

The OPRM is designed to automatically detect and suppress stability related neutron flux oscillations which could result in conditions exceeding the MCPR Safety Limit. Reliability is enhanced by using highly redundant OPRM cells providing input to a safety grade trip system described in Section A.4.1. These design features ensure compliance with GDC-12 .

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Analytical MCPR Safety Limit compliance will be demonstrated for all expected modes of GE BWR neutronic/thermal-hydraulic neutron flux oscillations (defined in Section 6.1). Although the OPRM system is expected to be capable of responding to other postulated modes of flux oscillations, demonstrating MCPR compliance for such modes is not necessary, for the reasons described in Section 6.1.

A.4.2.1.2 Design/Licensing Philosophy

The OPRM uses a large fraction of, if not all, operable LPRMs. Because they are evenly distributed throughout the reactor, the fission chamber LPRMs are capable of immediately responding to any neutron flux oscillations capable of creating an MCPR concern.

The overall design philosophy of the OPRM system is to generate a trip signal at a sufficiently low oscillation amplitude such that margin to the MCPR Safety Limit is provided. Operating experience with core-wide and regional oscillations shows that LPRMs readily respond to oscillations, and the OPRM system, consisting of many cells, will readily respond as well.

LPRMs also readily respond to a wide variety of normal operating maneuvers and expected events, including direct electrical or mechanical malfunctions of the LPRM detector, seals, cable, or amplifier. Individual LPRMs are also subject to electrical interference, and can respond very strongly to nearby control rod motion. For these reasons, the OPRM system may use multiple LPRMs as a means of maintaining a strong response to a neutron flux oscillation while minimizing the susceptibility to false signals associated with a single LPRM, or will utilize a detection algorithm designed to minimize the susceptibility to false signals associated with a single LPRM.

A.4.2.1.3 Setpoint Basis

The OPRM oscillation recognition algorithm is intended to discriminate between true stability-related neutron flux oscillations and other flux variations that may be expected during plant operation. The algorithm design has two primary objectives. The first is to provide a sufficiently low amplitude trip setpoint such that minimum reliance on analysis is required to demonstrate MCPR margin during a postulated neutron flux oscillation. Second, the algorithm must be capable of identifying stability-related neutron flux oscillations and discriminating against false signals from other expected plant evolutions. This design objective is essential for maintaining reliable power operation while simultaneously minimizing unnecessary challenges to the suppression function.

Extensive evaluation of operating plant data is required to determine the combination of algorithm and OPRM setpoints which meet the design objectives. Once the algorithm is defined and the minimum amplitude for the OPRM setpoint is determined, confirmatory analysis to demonstrate that the OPRM design provides margin to the MCPR Safety Limit will be performed for expected oscillation modes using the Section 6.0 methodology. The algorithm and setpoints discussed in Appendix B have been evaluated using these methods. The results of the example calculations are presented in Section 6.3.3.

The final algorithm/setpoint design may be subjected to in-plant testing, with the plant trip function disabled, to ensure the design adequately discriminates against expected plant transient responses. This testing will be done on a lead plant or lead plant-type basis or could be a part of the normal testing program for each unit installing an OPRM system. During this testing period, current plant procedures based on the Interim Corrective Actions of Reference 1 will be retained.

A.4.2.2 Oscillation Types and Modes

The OPRM is capable of responding to the expected modes of BWR stability-related oscillations. The design basis of the OPRM system shall be to generate a trip signal during oscillations of sufficiently low amplitude to provide margin to the MCPR Safety Limit for all expected modes of BWR oscillations.

These expected modes are core-wide, first-order side-by-side, and first-order precessing. Section 6.1 describes the expected modes and the basis for limiting consideration to these modes.

A.4.2.3 OPRM Design Features

A.4.2.3.1 Trip Function Bypass Setpoints

The OPRM trip function is automatically bypassed below approximately 30% power (low power bypass) and above approximately 60% core flow (high flow bypass). The reasons for this are (1) to allow selected maintenance and calibration activities to be performed during normal unit operation without creating channel trips, and (2) to prevent unnecessary false OPRM trips from potential operating events, LPRM instrument malfunctions, electrical interference, etc. Additionally, the low power bypass ensures that LPRM signals of sufficient magnitude are available so that most OPRM cells will be operable (Section A.4.2.3.2 below).

The automatic bypass features do not affect OPRM system operability requirements. In the run mode with core flow above the high flow bypass or power less than the low power bypass, the OPRM is operable, but the trip function is bypassed. The trip function is automatically enabled upon operation above the low power bypass and below the high flow bypass. Automatic bypass features are common in RPS design. Examples include the turbine control valve fast closure scram bypass when steam flow is less than a specified value and the MSIV closure scram in startup or hot standby modes which is bypassed at low pressure.

These setpoints have been selected to conservatively bound the regions of the power/flow map where an instability may occur. They are based on GE-BWR world-wide operating experience, which has not resulted in any instabilities below 40% power or above 45% core flow. The setpoints are experience based, and are very conservative. Additionally, the setpoints can be confirmed using the Section 5.1 methodology.

A.4.2.3.2 LPRM Bypass on Low Signal Level

To ensure that only valid LPRM signals are utilized in the OPRM, low reading LPRMs are automatically excluded from each OPRM cell's calculated response. The setpoint will be at approximately 5% to 10% of scale, which is consistent with a similar bypass built into existing Rod Block Monitor (RBM) circuitry. A very low-reading LPRM is normally a bypassed or malfunctioning LPRM which would not respond to changes in neutron flux and, therefore, must not be included as an OPRM input signal.

A.4.2.3.4 Bypassed LPRM Detector Basis

In the current APRM system, it is not uncommon to have some LPRMs bypassed due to an electrical or mechanical failure of one of the detector's components. When a failure is diagnosed, plant personnel manually bypass the LPRM, resulting in a downscale signal which automatically excludes it from being used in the OPRM system.

OPRM operability is not significantly impacted by such bypassed LPRMs, and no changes to existing LPRM/APRM Technical Specifications are required. This is because:

(1) The highly redundant and low minimum number of required LPRMs in the OPRM cell design ensures that large numbers of cells will remain operable, even with very large numbers of LPRMs bypassed.

(2) Approximately 75% (100% for BWR/6) of the LPRMs are subject to existing Technical Specification operability requirements, which ensure that at least half of these LPRMs are operable. Technical Specifications also require at least two LPRMs per axial level for each APRM to be operable, which essentially mandates even more LPRMs in service because failure distributions are not always evenly distributed per each axial level inside ach APRM channel.

(3) Actual reliability of LPRMs is very high relative to what would create an OPRM reliability concern. Because only a fraction of the available LPRMs is needed for an OPRM cell to be operable, as few as 50% or less of the core's LPRMs could enable all OPRM cells to be operable. Given the significant redundancy of the cell configuration of each OPRM channel, even half of the cells being inoperable per trip channel would not significantly alter its capability.

(4) Actual LPRM reliability at the worst points in a cycle is estimated to be better than 75%, which is far beyond what is needed. Because LPRMs are required for efficient monitoring of the reactor's power distribution, each utility has a strong incentive to maintain high LPRM reliability.

To verify that bypassed LPRMs will not create an OPRM operability concern, a confirmatory statistical evaluation using the Monte Carlo approach described in Section 6.3.2.4 will be performed. The evaluation will consider the actual number of LPRMs used per OPRM cell and plant or plant-type specific OPRM configurations. An example calculation is provided in Section 6.3.3.

A.4.2.3.5 Oscillation Recognition

As described in Section A.3.1.4, the OPRM features an algorithm that is able to discriminate between stability related neutron flux oscillations and other neutron flux variations that are expected to occur in the plant. The algorithm monitors the OPRM cell responses and provides a trip signal if an oscillation with sufficient magnitude is detected. Two examples of such an algorithm are provided in Appendix B with the algorithm described in Section B.1 as the specific algorithm for this option. The algorithm described in Section B.2 is an example of a viable alternative. The detection and suppression licensing methodology described in Section 6.0 explicitly accounts for the oscillation magnitudes possible with chosen algorithm setpoints, and the delays and overshoots that may occur prior to oscillation termination by the ASF.

A.4.2.3.6 OPRM Alarm Basis

The OPRM alarm circuit will:

(1) Provide control room warning of an oscillation prior to an OPRM trip.

(2) Not alarm during expected plant normal operation and expected maneuvers.

A.4.2.4 Operational Considerations

Because the OPRM design and licensing basis is to automatically detect and suppress expected modes of neutronic/thermal-hydraulic oscillations, no operating restrictions are required. Consistent with systems which provide alarms or safety functions, operating procedures will be generated for responding to OPRM alarms and half or full trip conditions. The generically expected operator actions for these conditions are discussed in Section A.4.5.

It is expected that plant procedures will be developed which alert operators to conditions that could result in oscillations, and describe the appropriate actions to manually suppress them should they occur. The emphasis of such procedures will be scram avoidance, since safe operation of the reactor will be assured by the ASF.

A.4.3 Methodology Application

A.4.3.1 Oscillation Algorithm

The approach to establishing the OPRM setpoints is to first determine an acceptably low setpoint such that expected plant evolutions will not result in an OPRM system trip, and then confirm that the setpoint provides margin to the MCPR Safety Limit. Therefore, evaluation of plant operating data against potential trip algorithms is a necessary step in the determination of the setpoints. Basic characteristics of oscillations are already known from test data and operating experience. Sample trip algorithms have been conceptually designed based on this information, and are described in Appendix B. Neutron flux signals generated by a simplified point kinetics model (including the effects of random noise) and digitally recorded plant data during various maneuvers are analyzed to determine the margin to trip for expected plant maneuvers without oscillations. Desired trip margins will be established based on trip avoidance and previous experience with other trip systems.

The analytical methodology used to demonstrate that the trip algorithm provides margin to the MCPR Safety Limit is described in detail in Section 6.0. The methodology simulates LPRM and OPRM cell responses to oscillations of

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various growth rates. These simulations explicitly account for delays associated with oscillation recognition by the algorithm and delay time associated with the ASF. Sections 6.2 and 6.3 detail how these delays and the algorithm setpoints themselves are related to the MCPR performance of the limiting bundles, and how uncertainties associated with oscillation recognition are accounted for. Digitally recorded data from actual BWR instability events will also be evaluated using the trip algorithms. This evaluation will further confirm that the trip algorithm can readily identify the occurrence of oscillations.

A.4.3.2 Detection and Suppression Oscillation Methodology

Any detection and suppression system requires a method for relating the LPRM responses during expected modes of oscillations to the MCPR of the limiting fuel assemblies. This basic oscillation methodology for the OPRM is described in detail in Section 6.2. Application of this methodology, described in Section 6.3, considers the various uncertainties and initial conditions associated with defining the oscillation response of limiting bundles. Section 6.4 describes how this generic methodology will be applied to determine plant specific setpoints. Appropriate parameters will be reviewed to ensure that the setpoint remains adequate for future reload cycles.

A.4.3.3 Trip Bypass on Low Power/High Flow

As described in Section A.4.2.3.1, the OPRM trip function is bypassed at high core flows and low power levels based on conservative application of oscillation operating experience. The regional exclusion boundary definition methodology, described in Section 5.1, will be used to confirm that the high flow and low power trip bypass setpoints are appropriate.

A.4.4 Technical Specification Implementation Philosophy

The OPRM instrumentation provides inputs to RPS or SRI functions and, therefore, the Technical Specifications involving the OPRM system will be similar to the existing RPS instrumentation specifications. The specifications will provide detail involving the minimum number of channels required per trip system. The LPRM operability requirements for the APRMs will be sufficient and, therefore, no additional LPRM requirements for the OPRM will be necessary. The specification will also provide information regarding applicability and actions required if the requirements of the OPRM specification are not met. Setpoints and surveillance requirements similar to other RPS instrumentation will be provided such that proper testing and operability can be performed/determined. Surveillance frequencies and allowable out-of-service times will be developed consistent with the reliability of the microprocessor design. Notations regarding bypassing of the system and other features will also be included. With this system installation, the requirement for actions denoted in NRC Bulletin 88-07 and SIL 380 will be eliminated.

A.4.5 Operator Guidance

The OPRM system will generate alarms, half scram or SRI actuations, or full actuations as required. Operator interface with the OPRM system will be through front panel annunciators, CRT displays or other information presentation systems. Operator response to OPRM system alarms and channel trips (half or full) will be similar to operator response to other alarms and trips and will be supported by appropriate training. The following recommendations are provided by the BWROG regarding operator response to OPRM system alarms and trips.

> The operator will be required to investigate the cause of the alarm or channel trip. Upon determination that the OPRM system has contributed to the alarm or channel trip, the operator will proceed to locate the area of oscillation through the use of back panel CRT displays, flashing downscale/upscale LPRM lights and alarms, review of LPRM hardwire displays via rod selection, or other optional displays. Having determined the cause and area of concern relating to the OPRM system alarm or channel trip, the operator will take proper actions to mitigate thermal-hydraulic instabilities if evidence of such instabilities exists. Operator action to suppress thermal-

hydraulic instabilities may include insertion of CRAM rods and/or an increase in core flow as deemed appropriate.

In addition, for a trip of both reactor recirculation pumps, the operator will assure the reactor is stable before attempting to restart the recirculation pumps. All plants are expected to provide operator training/guidance in oscillation prevention and mitigation for scram or SRI avoidance reasons.

A.5 OPTION III-A - LPRM BASED SYSTEM

A.5.1 System Description

A.5.1.1 General Description

The Local Power Range Monitor (LPRM) based system (LBS) is a microprocessor-based monitoring and protection system capable of detecting a thermal-hydraulic instability, providing an alarm on low oscillation magnitude, and initiating an Automatic Suppression Function (ASF) to suppress an oscillation prior to exceeding safety limits.

The LBS is a Class 1E protection system which monitors the output of selected LPRM detectors. The LBS conforms to all applicable requirements of IEEE-279-1971. LBS channels are provided in a one-to-one correspondence to the Average Power Range Monitor (APRM) channels. The LBS provides inputs to trip logics which initiate an ASF.

The LBS function is in parallel with, and independent of, the existing Class 1E and non-1E functions of the Power Range Neutron Monitoring (PRM) System. The LBS does not affect the design bases for the existing PRM components, their calibration, or their separation schemes.

The LBS utilizes amplified LPRM signals for selected LPRM detectors from available locations in the PRM panels. These LPRM signals are chosen from the associated APRM channels such that the resulting LBS channel response provides adequate coverage of expected oscillation modes. Each LBS channel comprises up to eight LPRM inputs from one APRM channel, representing geometrically diverse (one per octant) regions of the reactor core. In this way, each LBS channel has the capability to detect expected oscillation modes.

Each LBS channel consists of a Class 1E microprocessor unit fabricated on a circuit board sized to fit in an LPRM flux amplifier card slot in the APRM chassis. The LBS card supports up to eight LPRM inputs, an APRM flux input, and an APRM (drive) flow input.

The LBS does not represent the first application of microprocessors in nuclear service. Several microprocessor based control units are commercially available for nuclear safety-related service. Some modules, such as GE's NUMAC and Westinghouse's Eagle 21, have been reviewed by the NRC; SERs have been issued for their safety related use in other applications. As is typical for these types of devices, these systems perform safety-related and non safety-related functions, and interface with other 1E and non-1E systems, for which external and internal system isolation and fault tolerance per IEEE-384 are required. The software will be qualified in accordance with Regulatory Guide 1.152 requirements.

A.5.1.2 Suppression Function

The LPRM-based system provides inputs to an ASF whose purpose is to suppress oscillations prior to exceeding the MCPR Safety Limit. It may be installed and maintained as a Reactor Protection System (RPS) trip function or may provide inputs for a Select Rod Insert (SRI) function.

The SRI function, as presently used, is intended to reduce core power to less than the turbine bypass capacity, so that the unit avoids a scram during a load rejection event. The same function may be used to reduce power to suppress oscillations without a full scram. Verification of this function's capability to effectively terminate a thermal-hydraulic instability event will be required for those plants considering this option.

For implementation as a RPS function, the LPRM-based system provides input to the appropriate RPS trip channel(s) consistent with the function and number of channels being added. The LBS channels tie into the existing APRM trip logic, providing the fourth APRM trip function (the others being inoperable, upscale flux, and upscale flow-biased neutron or thermal flux). Reactor scram will therefore occur when at least one channel in each RPS trip system is in the tripped condition. For a solid state RPS logic plant, any two RPS channels in trip will result in a reactor scram. For implementation as a SRI function, appropriate trip logic will be chosen to ensure high reliability of the ASF. For the purposes of this report, channel assignments will be discussed relative to a RPS function.

The instability trip function will not be used to initiate the Alternate Rod Insertion (ARI) system. The ARI trip function, installed per 10CFR50.62, is not required to provide an automatic scram function which is redundant and diverse to the instability trip function. ATWS/instability events have been shown to develop sufficiently slowly such that manual scram techniques, or manual ARI initiation, are sufficient to back up instability trip system failures. If the reactor becomes isolated from the main condenser, the ensuing transients will provide the necessary ARI initiation from water level or reactor pressure signals.

A.5.1.3 LPRM Assignments

The purpose of the LPRM-based system is to provide detection and suppression of expected oscillation modes in a BWR. This is achieved by monitoring LPRMs that are representative of flux levels in core regions that are most responsive in the expected oscillation modes. The LBS does not utilize a full complement of LPRM inputs. The choice of LPRM inputs for the LBS ensures adequate response to expected oscillation modes.

Because the LBS provides inputs to trip logics, channel redundancy and reliability are required. Additionally, protection from spurious actuations and allowances for expected LPRM failures and bypasses must be incorporated into the system design. In general, all of these considerations were included in the original design of the Average Power Range Monitor (APRM) systems and, therefore, where possible, the available LPRM assignment schemes between the APRM channels are used. The following system design features are incorporated to satisfy the stated design requirements:

Requirement	Design Feature
Detection of expected oscillation modes	LPRMs at the most responsive core locations during expected oscillation modes are selected.
Redundancy	A sufficient number of LPRM inputs (up to eight per LBS channel) are selected. LBS redundancy remains the same as APRMs.
Reliability Avoid spurious actuations Tolerant to LPRM bypass/failure	A total of 32, 48, or 64 LPRMs (one LPRM from each core octant per LBS channel) will be monitored. A minimum of eight operable LPRMs can assure adequate core stability protection. The eight LPRMs must be distributed such that each RPS channel monitors two LPRMs. The two LPRMs monitored by an RPS channel cannot be in the same core octant or in mirror-symmetric core octant pairs. The use of a detection algorithm (e.g. Appendix B) to process several individual LPRM signals assures a reliable trip function and high sensitivity to oscillations, while minimizing spurious actuations due to a single LPRM malfunctions.

Sample octant boundaries for a small-core BWR are displayed in Figure A-26. This choice of octant boundaries minimizes the impact of bypassed or failed LPRMs on LBS sensitivity, since the strongest response during expected oscillation modes occurs on the octant boundaries (i.e., the immediately-adjacent octant will show a comparable response during expected oscillation modes). Alternate octant boundaries are displayed in Figure A-27 (rotated 22.5° from Figure A-26) which are chosen to provide the strongest response of particular LBS channels during expected oscillation modes (i.e., boundaries are chosen such that the strongest response during expected oscillation modes occurs midway between boundaries).

Sample LPRM assignments to LBS channels for small cores using the boundary strategy of Figure A-26 are shown in Figure A-28. For purposes of operability determination, LPRM string 16-17 (arbitrarily) monitors the west-southwest octant and string 32-33 monitors the south-southwest octant. Sample LPRM assignments for large cores using a similar boundary strategy are shown in Figure A-29.

The LPRM assignment strategy consists of selecting one LPRM in each core octant for each of the LBS channels. LPRMs are selected based on ensuring sensitivity to oscillations while minimizing the impact of LPRM failures. The ability to cause an ASF is assured for oscillations confined to regions as small as a core octant. In this assignment strategy, every LBS channel receives an LPRM input from each core octant; consequently, the reliability and redundancy of the LBS channels remain consistent with the APRM operability requirements.

The design objective, therefore, is to monitor 32, 48, or 64 LPRM inputs individually, one from each core octant for each of the four, six, or eight LBS channels. The licensing basis of the LBS solution, however, allows for a minimum of eight operable LPRM inputs, two from each RPS channel. The two LPRMs in an RPS channel cannot be in the same core octant or in mirror-symmetric core octant pairs. By applying mirror symmetry across the core center, in effect, all eight core octants are monitored by only four octants in each RPS trip system for the expected modes of oscillation.

A.5.1.4 Trip and Alarm Functions

Each LBS channel performs a real-time analysis of LPRM signal responses. Determination of peak-to-average values of LPRM signals is used to evaluate the magnitude of oscillations. Time-averaging of responses is used to provide a time-dependent baseline for normalizing oscillation magnitudes. The signal sampling and computational frequency are well above the expected oscillation frequency, essentially producing a continuous and simultaneous measurement of all LPRM inputs to the LBS channel. Any individual LPRM signal input which satisfies the conditions and criteria of the trip algorithm will be sufficient to produce a LBS channel trip.

A description of a sample algorithm is provided in Appendix B. Many forms of algorithms may be used to distinguish oscillations from noise or other plant occurrences. Algorithms use the known frequency of oscillations (i.e., 0.3 to 0.7 Hz) to aid in screening out other signal variations such as electrical spiking, 60 Hz noise, and reactor system and control system transients. Time delays for the channel trip introduced by the algorithm will be appropriately factored into the setpoint analyses as discussed in Section 6.3.

The LBS alarm is designed to provide the operator with warning prior to a channel trip. This may be accomplished using the same algorithm as discussed above for the channel trip with a lower setpoint.

A.5.1.5 Operating Bypasses

The LPRM-based system will be operable in the power range of operation (i.e., Mode 1). However, historical data and operating experience have shown that the protective function is not required at low core power or at high core flow conditions. Because spurious actuation is always a concern for trip channels, it is appropriate to provide an operating bypass under conditions when the protective function is not required. LPRM signal noise at low power conditions and bistable core flow at high core flow conditions are examples of system inputs which may result in unnecessary challenges if these systems are not bypassed.

The system interfaces with the existing APRM Reactor Recirculation System Drive Flow Units, which are used for a high core flow system bypass. This bypass is removed under single loop operating conditions above the low power bypass setpoint. The system also interfaces with the APRM module outputs for a low power system bypass.

Because this bypass is enabled by process conditions, the trip function becomes automatically functional given any plant operating transient of interest. The bypass functions are considered to be part of the Class 1E portion of the solution.

A.5.1.6 LPRM Bypasses

The LPRM-based system communicates with the LPRM amplifier cards such that it can detect and account for (in a limited sense) bypassed LPRMs. Minimum LPRM operability requirements for ensuring LBS operability (consistent with Section A.5.1.3) will be administratively controlled by Technical Specifications.

LPRM signals which do not exceed a minimum value may contain process or signal noise components which may affect system response. The detection algorithm may bypass LPRM signals which fall below system requirements, or may normalize the LPRM oscillation peak magnitude to a core-wide average. The adjustments will be automatically enabled or removed based on process conditions.

A.5.1.7 Operator Interface

No direct control interface is required for the LPRM-based system safety-related trip functions. However, the trip functions have a range of alarm, display, and other capabilities. The specific non-1E functions will be defined in the engineering development of the function, device, and software. No credit is taken for operator interface in achieving the system functional performance requirements.

A.5.2 Licensing Approach

A.5.2.1 Overview

A.5.2.1.1 GDC-12 Compliance

The LPRM-based system will be designed to automatically detect and suppress stability-related neutron flux oscillations which could result in conditions exceeding the MCPR Safety Limit. Reliability will be enhanced by using a variety of LPRM inputs to redundant safety grade LBS trip channels described in Section A.5.1. These design features ensure compliance with GDC-12.

Analytical MCPR Safety Limit compliance will be demonstrated for expected modes of GE BWR neutronic/thermal-hydraulic neutron flux oscillations (defined in Section 6.1). Although the LBS is expected to be capable of responding to other postulated modes of flux oscillations, demonstrating MCPR compliance for such modes is not necessary, for the reasons described in Section 6.1.

A.5.2.1.2 Design/Licensing Philosophy

By using a geometrically-diverse selection of operable LPRMs, the LBS uses the best available instrumentation for detecting an oscillation. Because they are distributed throughout the reactor, the fission chamber LPRMs are capable of immediately responding to any neutron flux oscillations capable of creating a MCPR concern.

The overall design philosophy of the LBS is to generate a trip signal at a sufficiently low oscillation amplitude such that margin to the MCPR Safety Limit is provided. Operating experience with core-wide and regional oscillations shows that LPRMs readily respond to oscillations, and the LBS will readily respond as well.

LPRMs also readily respond to a wide variety of normal operating maneuvers and expected events, including direct electrical or mechanical malfunctions of the LPRM detector, seals, cable or amplifier. Individual LPRMs are also subject to electrical interference, and can respond very strongly to nearby control rod motion. For these reasons, the LBS detection algorithm will be designed to minimize the susceptibility to false signals associated with a single LPRM.

A.5.2.1.3 Setpoint Basis

The LBS detection algorithm is intended to discriminate between true stability-related neutron flux oscillations and other flux variations that may be expected during plant operation. The algorithm design has two primary objectives. The first is to provide a sufficiently low amplitude trip setpoint, such that minimum reliance on analysis is required to demonstrate MCPR margin during a postulated neutron flux oscillation. Second, the algorithm must be capable of identifying stability-related neutron flux oscillations and discriminating against false signals from other expected plant evolutions. This design objective is essential for maintaining reliable power operation, and simultaneously minimizes unnecessary challenges to the suppression function.

Extensive evaluation of operating plant data is required to determine what combination of algorithm and LBS setpoint will meet the design objectives. Once the algorithm is defined and the minimum amplitude for the LBS setpoint is determined, confirmatory analysis to demonstrate that the LBS design provides margin to the MCPR Safety Limit will be performed for expected oscillation modes using the Section 6.0 methodology.

The final algorithm/setpoint design may be subjected to in-plant testing, with the plant trip function disabled, to ensure that the design adequately discriminates against expected plant responses. This testing could be done either on a lead plant or lead plant-type basis, or could be a part of the normal testing program for each unit installing an LBS.

During this testing period, current plant procedures based on the ICAs of Reference 1 will be retained.

A.5.2.2 Oscillation Types and Modes

The LBS is expected to be capable of responding to any reasonably postulated mode of BWR stability-related oscillations. The design basis of the LBS shall be to generate a trip signal during oscillations of sufficiently low amplitude to provide margin to the MCPR Safety Limit for expected modes of BWR oscillations. These expected modes are core-wide, first order side-by-side, and first order precessing. Section 6.1 describes the expected modes and the basis for limiting considerations to these modes.

A.5.2.3 LBS Design Features

A.5.2.3.1 Trip Function Bypass Setpoints

The LBS trip function will be automatically bypassed below approximately 30% power (low power bypass) and above 60% core flow (high flow bypass). The reasons for this are (1) to allow selected maintenance and calibration activities to be performed during normal unit operation without creating channel trips, and (2) to prevent unnecessary false LBS trips from potential operating events, LPRM instrument malfunctions, electrical interferences, etc. Additionally, the low power bypass ensures that LPRM signals of sufficient magitude are available so that meaningful LBS processing can be performed (see Section A.5.2.3.2).

The automatic bypass features do not affect LBS operability requirements. In the run mode with core flow above the high flow bypass or power less than the low power bypass, the LBS is operable, but the trip function is bypassed. The trip function will automatically be enabled upon operation above the low power bypass and below the high flow bypass. Automatic bypass features are common in RPS design. Examples include the turbine control valve fast closure scram bypass when steam flow is less than a specified value and the MSIV closure scram in startup or hot standby modes which is bypassed at low pressure.

These setpoints have been selected to conservatively bound the regions of the power flow map where an instability may occur. They are based on GE-BWR world-wide operating experience, which has not resulted in any instabilities below 40% power or above 45% core flow. The setpoints are experienced based, and are very conservative. Additionally, the setpoints can be confirmed using the Section 5.1 methodology.

A.5.2.3.2 LPRM Bypass on Low Signal Level

To ensure that only valid LPRM signals are utilized in the LBS, low reading LPRMs are automatically excluded from the LBS calculated response. The setpoint will be at approximately 5% to 10% of scale, which is consistent with a similar bypass built into existing Rod Block Monitor (RBM) circuitry. A very low reading LPRM is normally a bypassed or malfunctioning LPRM which would not respond to changes in neutron flux and, therefore, must not be included as an LBS input signal.

A.5.2.3.3 Bypassed LPRM Detector Basis

In the current APRM system, it is not uncommon to have some LPRMs bypassed due to an electrical or mechanical failure of one of the detector's components. When a failure is diagnosed, plant personnel manually bypass the LPRM, resulting in a downscale signal which automatically excludes it from being used in the LBS.

LBS operability is not significantly impacted by such bypassed LPRMs since the failures occur randomly and only a small fraction of the monitored LPRMs are needed to satisfy the system requirements. However, minor changes to existing LPRM/APRM Technical Specifications are required to ensure operability of the LBS when LPRMs are bypassed.

The design basis of the LBS assumes four operable LPRMs for each RPS trip system (A and B). Through the use of mirror symmetry (based on the expected oscillation modes discussion of Section 6.1 and core loading and control rod patterns in use at all BWRs), the minimum LPRM operability requirement can be met with two operable LPRMs in each RPS channel (i.e., A1, A2, B1 and B2). LPRMs in the same RPS channel cannot be located in the same core octant or mirror-symmetric core octant pair. The Technical Specifications will provide administrative controls to ensure that this minimum operability requirement is met.

To assess the impact of bypassed LPRMs on LBS operability, a confirmatory statistical evaluation using the Monte Carlo approach described in Section 6.3.2.4 will be performed. The evaluation will consider the actual number of LPRMs in plant or plant-type specific LBS configurations.

A.5.2.3.4 Oscillation Recognition

As described in Section A.5.1.4, the LBS features an algorithm that will be able to discriminate between stability-related neutron flux oscillations and other neutron flux variations that are expected to occur in the plant. The algorithm will monitor the LPRM responses and provide a trip signal if an oscillation with sufficient magnitude is detected. Two examples of such an algorithm are provided in Appendix B with the algorithm described in Section B.1 as the specific algorithm for this option. The algorithm described in Section B.2 is an example of a viable alternative. The detection and suppression licensing methodology described in Section 6.0 explicitly accounts for the oscillation magnitudes possible with chosen algorithm setpoints, and the delays and overshoots that may occur prior to oscillation termination by the ASF.

A.5.2.3.5 LBS Alarm Basis

The LBS alarm circuit will:

(1) Provide control room warning of an oscillation prior to an LBS trip.

(2) Not alarm during expected plant normal operations and expected maneuvers.

A.5.3 Operational Considerations

Because the LBS design and licensing basis is to automatically detect and suppress expected modes of neutronic/thermal-hydraulic oscillations, no operating restrictions are required. Consistent with systems which provide alarms or safety functions, operating procedures will be generated for responding to LBS alarms and half or full trip conditions. The generically expected operator actions for these conditions are discussed in Section A.5.5.

It is expected that plant procedures will be developed which alert operators to conditions that could result in oscillations, and describe the appropriate actions to manually suppress them should they occur. The emphasis of such procedures will be scram avoidance, since safe operation of the reactor will be ensured by the ASF.

A.5.4 Methodology Application

A.5.4.1 Oscillation Algorithm

The approach to establishing the LBS setpoints is first to determine an acceptably low setpoint such that expected plant evolutions will not result in an LBS system trip, and then confirm that the setpoint provides margin to the MCPR Safety Limit. Therefore, evaluation of plant operating data against potential trip algorithms is a necessary step in the determination of the setpoints. Basic characteristics of oscillations are already known from test data and operating experience. Sample trip algorithms have been conceptually designed based on this information, and are described in Appendix B. Neutron flux signals generated by a simplified point kinetics model (including the effects of random noise), and digitally recorded plant data during various maneuvers are analyzed to determine the margin to trip for expected plant maneuvers without oscillations. Desired trip margins will be established based on trip avoidance and previous experience with other trip systems.

The analytical methodology used to demonstrate that the trip algorithm provides margin to the MCPR Safety Limit is described in Section 6.0. The methodology simulates LPRM and LBS responses to oscillations of various growth rates. These simulations explicitly account for delays associated with oscillation recognition by the algorithm and delay time associated with the ASF. Sections 6.2 and 6.3 detail how these delays and the algorithm setpoints themselves are related to the MCPR performance of the limiting bundles, and how uncertainties associated with oscillation recognition are accounted for.

Digitally recorded data from actual BWR instability events will also be evaluated using the trip algorithms. This evaluation will further confirm that the trip algorithm can readily identify the occurrence of oscillations.

A.5.4.2 Detection and Suppression Oscillation Methodology

Any detection and suppression system requires a method for relating the LPRM responses during expected modes of oscillations to the MCPR of the limiting fuel assemblies. This basic oscillation methodology for the LBS is described in Section 6.2. Application of this methodology (Section 6.3) considers the various uncertainties and initial conditions associated with defining the oscillation response of limiting bundles. Section 6.4 describes how this generic methodology will be applied to determine plant specific setpoints. Appropriate parameters will be reviewed to ensure that the setpoint remains adequate for future reload cycles.

A.5.4.3 Trip Bypass on Low Flow/High Power

As described in Section A.5.2.3.1, the LBS trip function is bypassed at high core flows and low power levels based on conservative application of oscillation operating experience. The regional exclusion boundary definition methodology (Section 5.1) will be used to confirm that the high flow and low power trip bypass setpoints are appropriate.

A.5.5 Technical Specification Implementation Philosophy

The LBS channels provide inputs to RPS or SRI functions, and therefore, the Technical Specifications associated with the LBS system will be similar to the existing RPS instrumentation specifications. The specifications will provide detail involving the minimum number of channels required per trip system. LPRM operability requirements for assuring the operability of each LBS channel will also be specified. The specification will also provide information regarding applicability and actions required if the requirements of the LBS specification are not met. Setpoints and surveillance requirements similar to other RPS instrumentation will be provided such that proper testing and operability can be performed/determined. Surveillance frequencies and allowable out of service times will be developed consistent with the reliability of the microprocessor design. Notations regarding bypassing of the system and other features will also be included. With this system installation, the requirement for actions denoted in NRC Bulletin 88-07 and SIL 380 will be eliminated.

A.5.6 Operator Guidance

The LBS system will generate alarms, half scram or SRI actuations, or full actuations as required. Operator interface with the LBS system will be primarily through front panel annunciators and through existing Neutron Monitoring System user interfaces. Operator response to LBS alarms and channel trips (half or full) will be similar to operator response to other alarms and trips and will be supported by appropriate training. The following recommendations are provided by the BWROG regarding operator response to LBS alarms and trips.

> The operator will be required to investigate the cause of the alarm or channel trip. Upon determination that the LBS has contributed to the alarm or channel trip, the operator will proceed to locate the area of oscillation through the use of flashing downscale/upscale LPRM lights and alarms, review of LPRM hardwire displays via rod selection, or other optional displays. Having determined the cause and area of concern relating to the LBS alarm or channel trip, the operator will take proper actions to mitigate thermal-hydraulic instabilities if evidence of such instabilities exists. Operator action to suppress thermal-hydraulic instabilities may include insertion of CRAM rods and/or an increase in core flow as deemed appropriate.

In addition, for a trip of both reactor recirculation pumps, the operator will assure the reactor is stable before attempting to restart the recirculation pumps. All plants are expected to provide operator training/guidance in oscillation prevention and mitigation for scram or SRI avoidance reasons.

Table A-1

BWR PLANT PARAMETERS

	DA	VY	MONT	FITZ	B1	B2	LS2
Fuel Assemblies	368	368	484	560	560	560	764
Power Density (kW/l)	51	51	40	51	51	51	50
APRM Trip Setpoint at Natural Circulation	62	54	62	62	62	54	62
Inlet Orifice Diameter (in)	2.090	2.222	2.148	2.090	2.430	2.090	2.430
Cycle	11	15	14	10	8	9	4
Fuel Type	GE 8x8	GE 8x8	GE 8x8	GE 8x8	GE 8x8	GE 8x8	GE 8x8
Expected Eigenvalue Separation (-$)							
Axial Mode	1.7-2.1	1.7-2.1	1.3-1.9	1.5-1.8	1.5-1.8	1.5-1.8	1.3-1.5
Azimuthal Mode	2.0-2.7	2.0-2.7	2.1-2.5	1.3-1.7	1.3-1.7	1.3-1.7	1.0-1.3

DA = Duane Arnold
VY = Vermont Yankee
MONT = Monticello
FITZ = FitzPatrick
B1 = Brunswick 1
B2 = Brunswick 2
LS2 = LaSalle-2

Table A-2

DUANE ARNOLD CYCLE 10 REGION BOUNDARY CALCULATIONS

Point *	Power/Flow (%/%)	Hot Channel Decay Ratio	Core Decay Ratio
High Rod Line			
1	66.8/40.0	0.28	0.77
2	65.0/38.0	0.31	0.86
3	64.1/36.9	0.33	0.92
Medium Rod Line			
4	54.7/40.0	0.21	0.63
5	51.0/35.0	0.25	0.78
6	48.7/32.0	0.30	0.91
Natural Circulation			
7	36.7/30.0	0.23	0.62
8	41.9/30.0	0.27	0.78
9	45.0/30.0	0.31	0.90
10	52.0/30.0	0.39	1.12

* See Figure A-7 for definition of points.

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Table A-3

FUNDAMENTAL AND AZIMUTHAL HARMONIC POWER DISTRIBUTIONS (CONTOURS) FOR DAEC ANALYSIS

Cycle	Cycle Exposure (MWd/ST)	Harmonic Orientation
10	200	NWSE
10	200	NESW
10	3000	EW
10	3000	NS
10	5400	NWSE
10	5400	NESW
10	End-of-Cycle	NWSE
10	End-of-Cycle	NESW

Table A-4

DAEC MCPR RESULTS FOR CORE WIDE OSCILLATIONS

	MCPR 95/95
110% Rod Line	1.417
100% Rod Line	1.391

Table A-5

DAEC MCPR RESULTS FOR REGIONAL OSCILLATIONS

	MCPR 50/50
110% Rod Line	1.266

Table A-6

LPRM CONFIGURATIONS FOR U.S. BWRs
(BWR/3-6)

Plant Name		Number of LPRM Strings	Plant Category
Vermont Yankee		20	Small Core
Duane Arnold			
Monticello		24	Small Core
Millstone		30	Large Core
Pilgrim			
FitzPatrick	Hatch 1,2	31	Large Core
Brunswick 1,2	Cooper		
River Bend		33	Large Core
Clinton		33	Solid State RPS
Dresden 2,3	Perry	41	Large Core
Quad Cities 1,2			
Browns Ferry 1,2,3	Fermi-2	43	Large Core
Peach Bottom 2,3	Limerick 1,2		
Hope Creek	LaSalle 1,2		
Susquehanna 1,2	Nine Mile Point 2		
Hanford 2			
Grand Gulf		44	Large Core

Table A-7

LARGE CORE LPRM ASSIGNMENTS
764 BUNDLE PLANT

BWR/3-5

OPRM	RPS Channel	APRM*	LPRM Group
A	A1	A,E	
B	B1	B,F	
C	A2	C	A
D	B2	D	B

BWR/6 (except Clinton)

OPRM	RPS Channel	APRM	LPRM Group
A	A1	A,E	(not applicable to BWR/6)
B	B1	B,F	
C	A2	C,G	
D	B2	D,H	

* Conventions for APRM/RPS assignments vary from plant to plant.

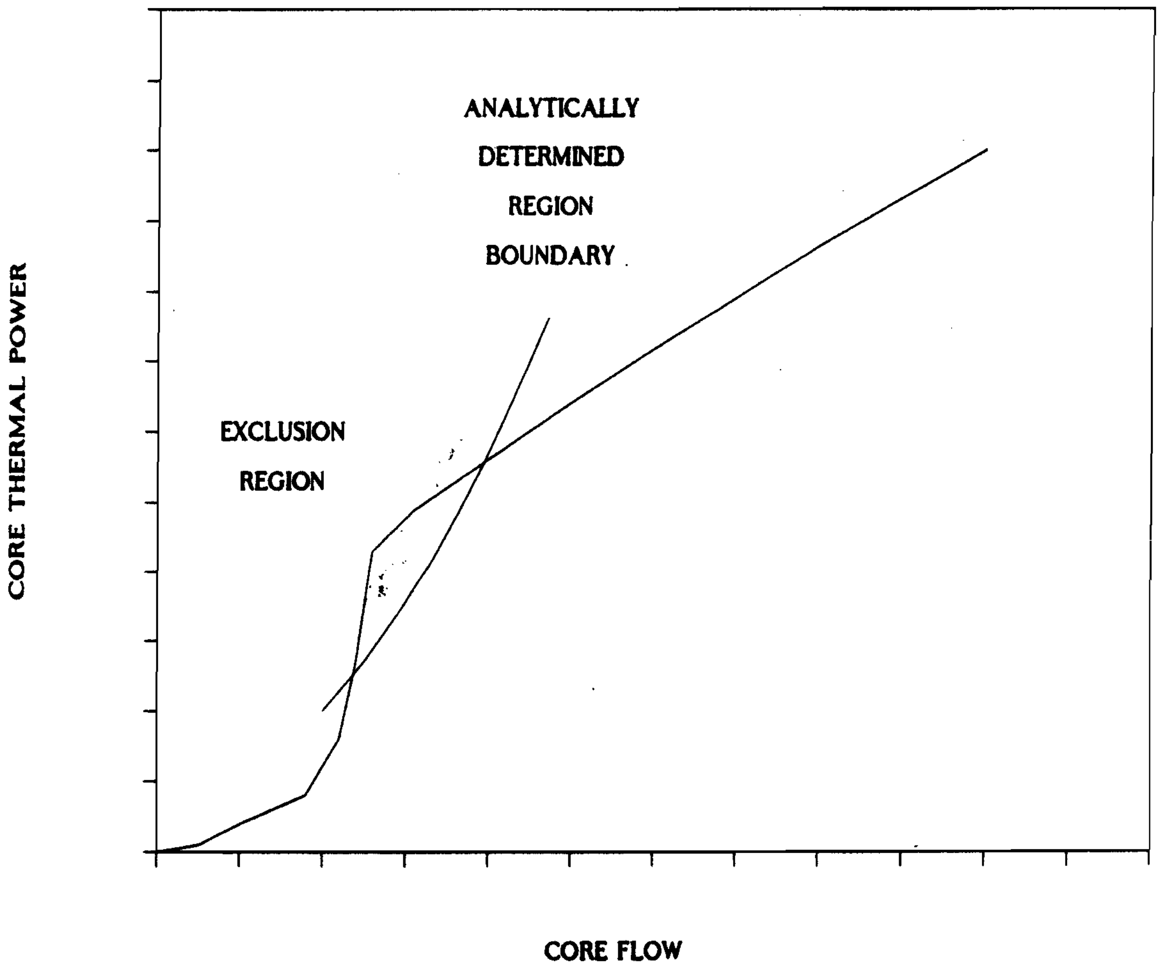

FIGURE A-1. EXAMPLE EXCLUSION REGION BOUNDARY

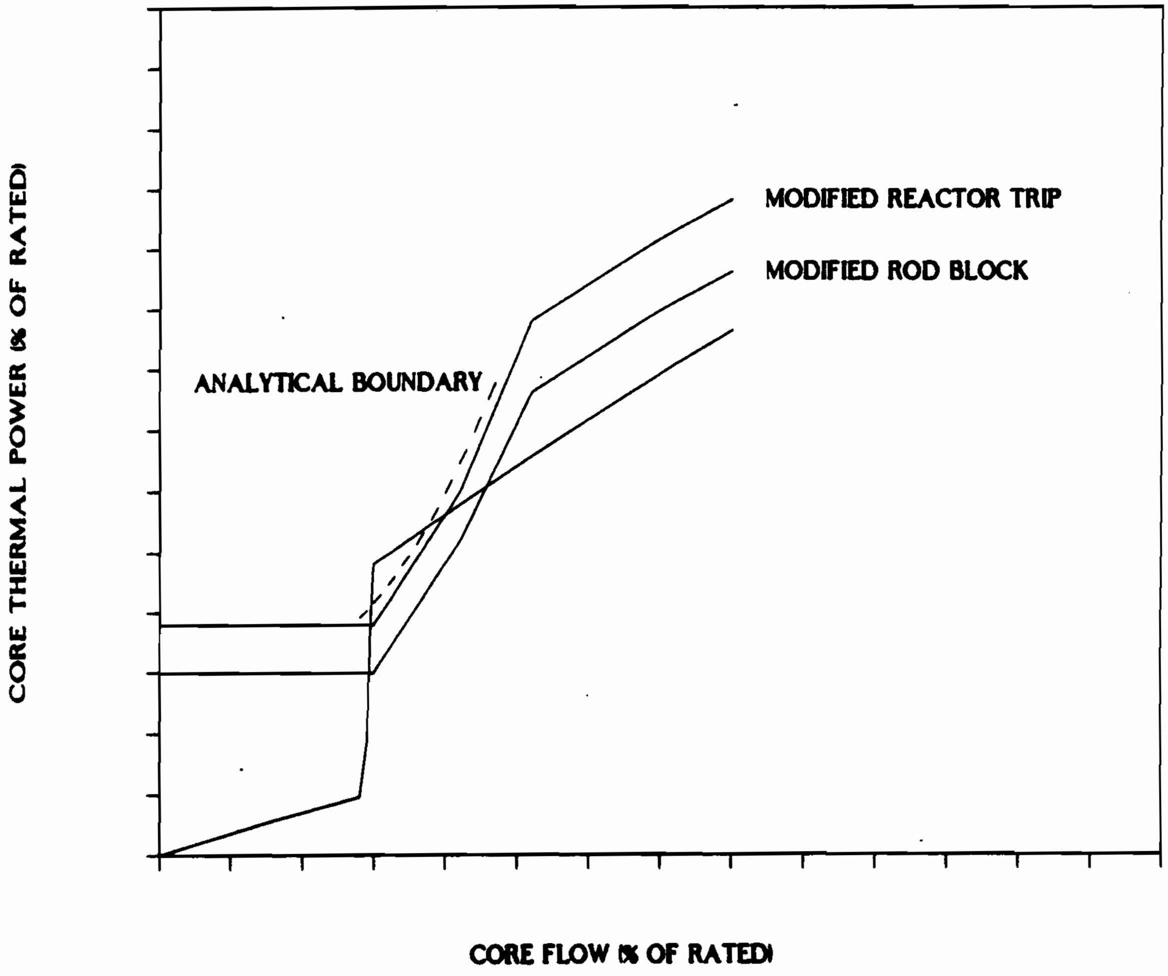

FIGURE A-2. EXAMPLE EXCLUSION REGION WITH MODIFIED FLOW BIASED REACTOR TRIP AND ROD BLOCK FUNCTIONS

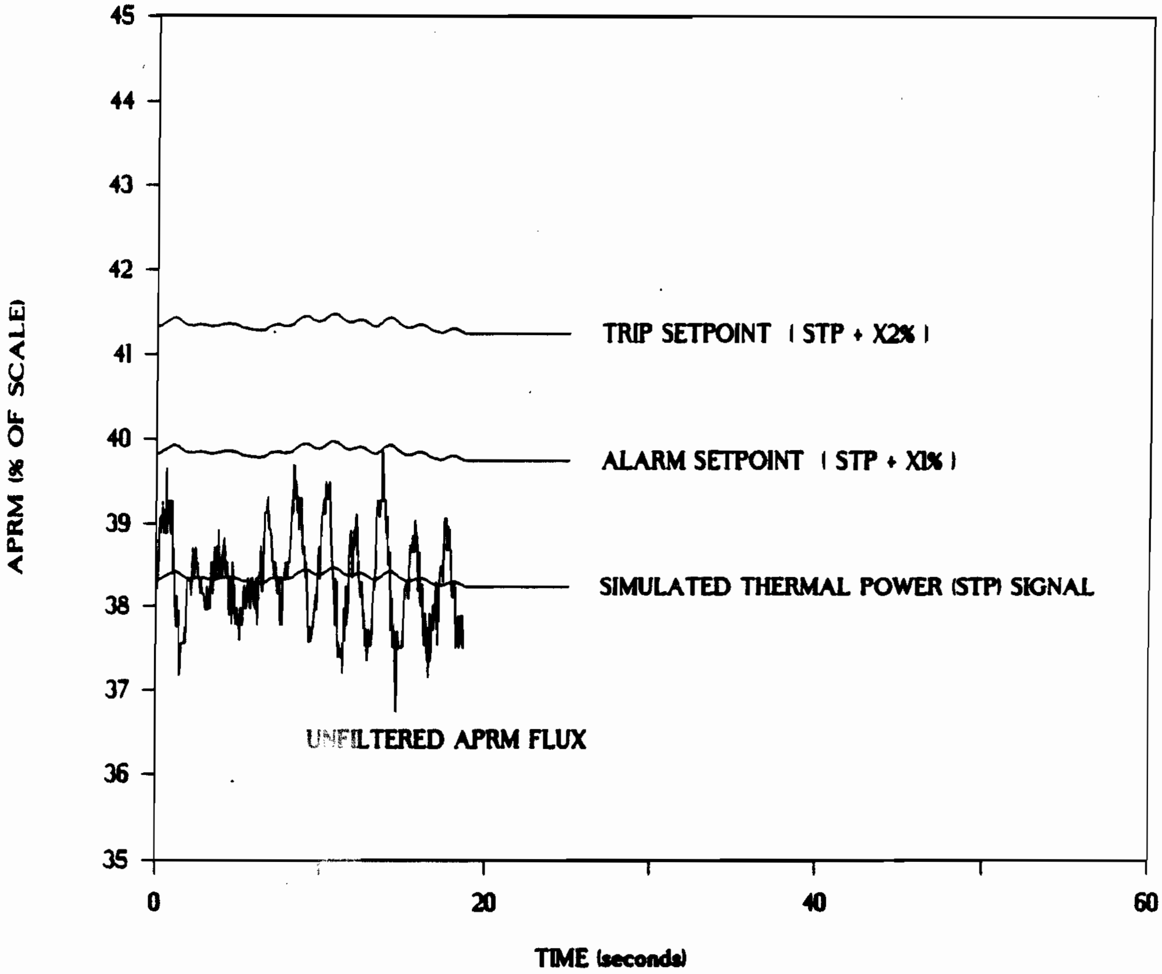

FIGURE A-3. OPTION I-C APRM STABILITY FLUX TRIP

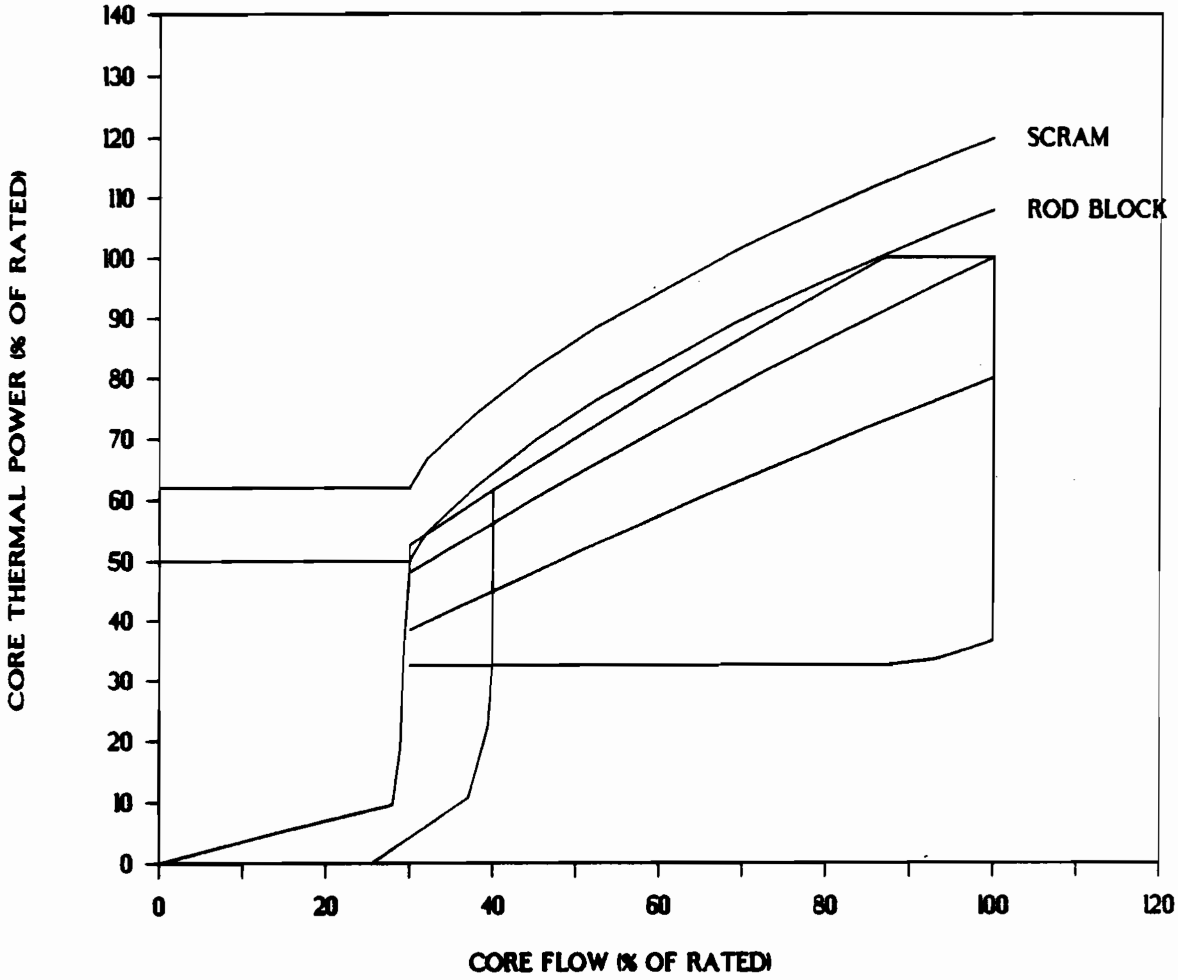

FIGURE A-4. FLOW-BIASED APRM NEUTRON FLUX SCRAM SYSTEM

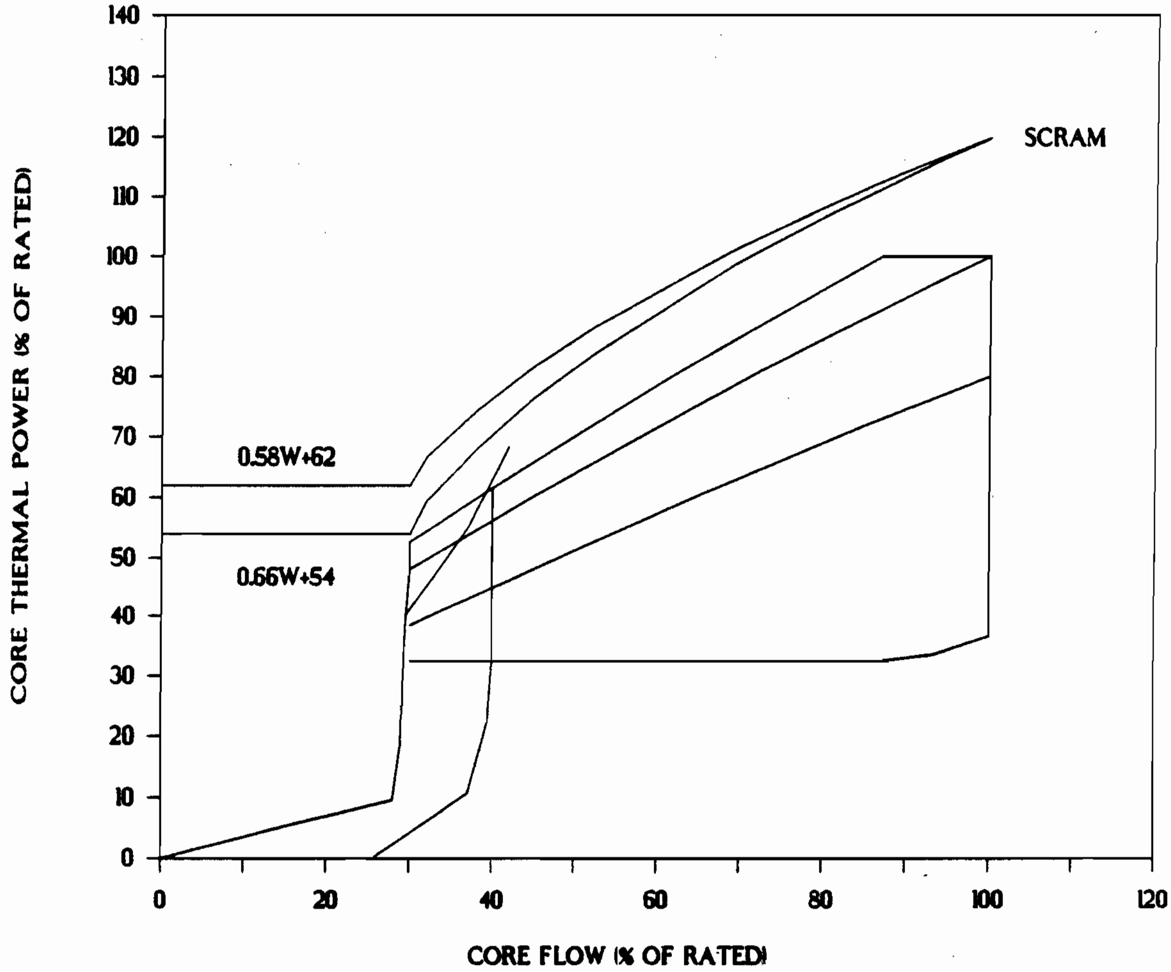

FIGURE A-5. PROTECTION FOR OPERATION INSIDE THE EXCLUSION REGION

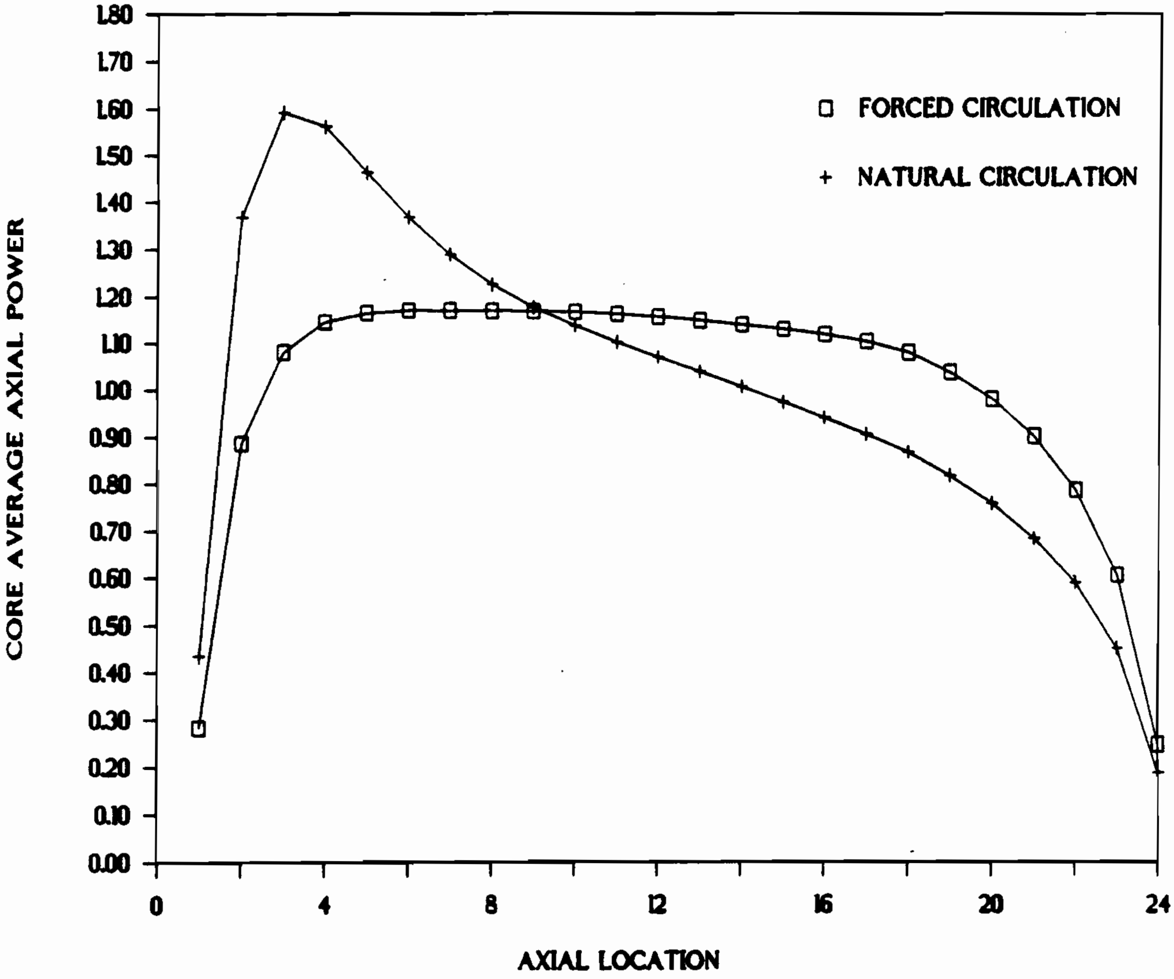

FIGURE A-6. DUANE ARNOLD CYCLE 10 EOC HALING AXIAL POWER DISTRIBUTIONS

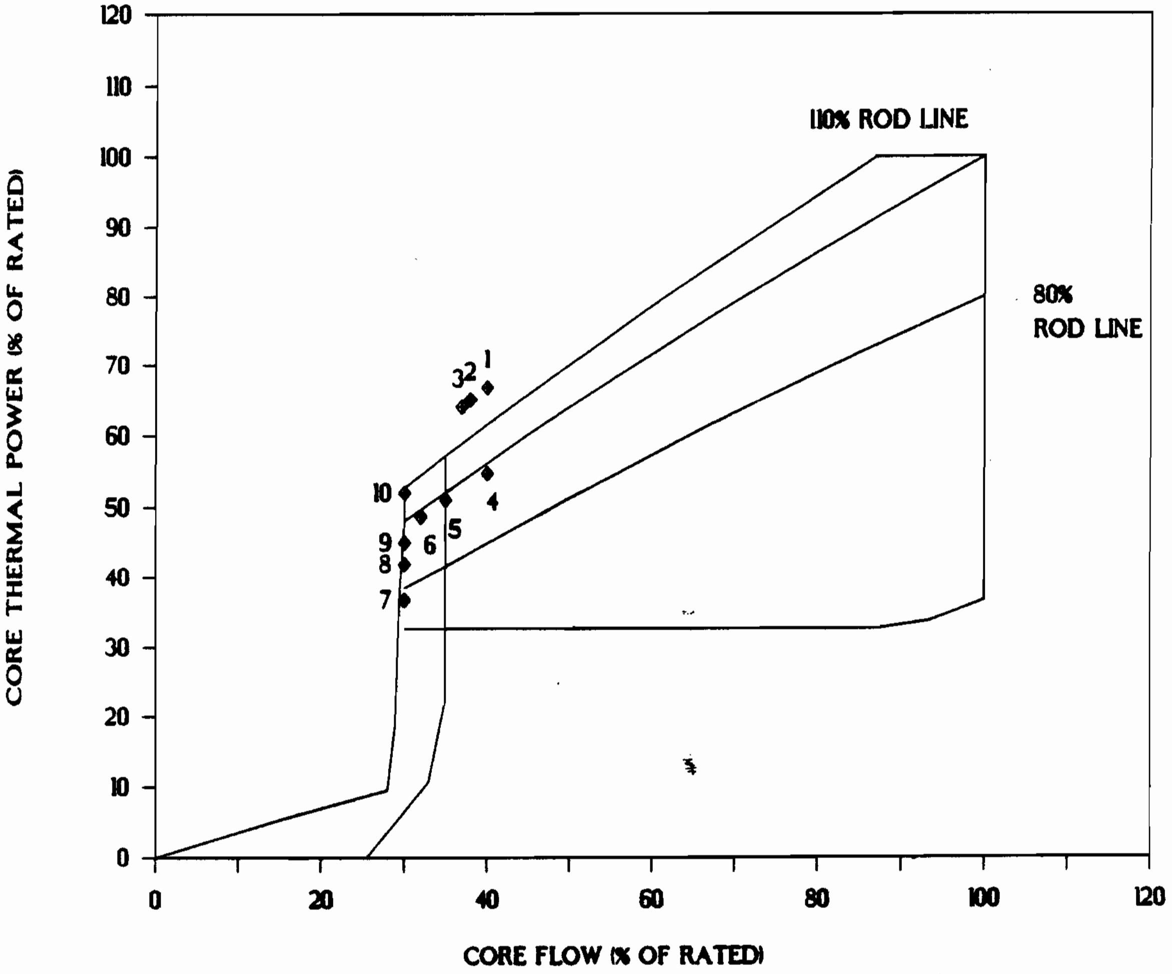

FIGURE A-7. DUANE ARNOLD CYCLE 10 REGION BOUNDARY DEFINITION ANALYSIS POINTS

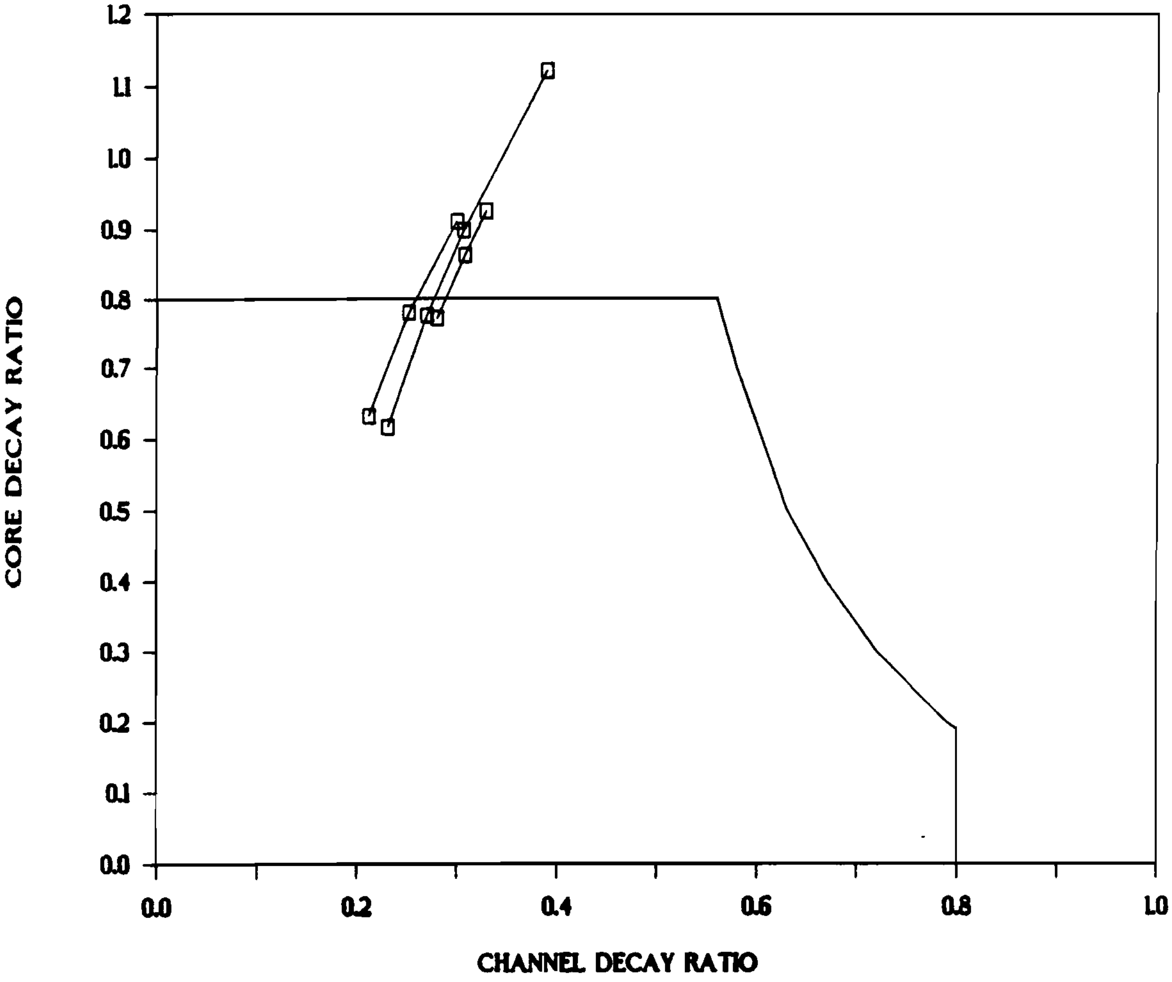

FIGURE A-8. DUANE ARNOLD CYCLE 10 DECAY RATIOS

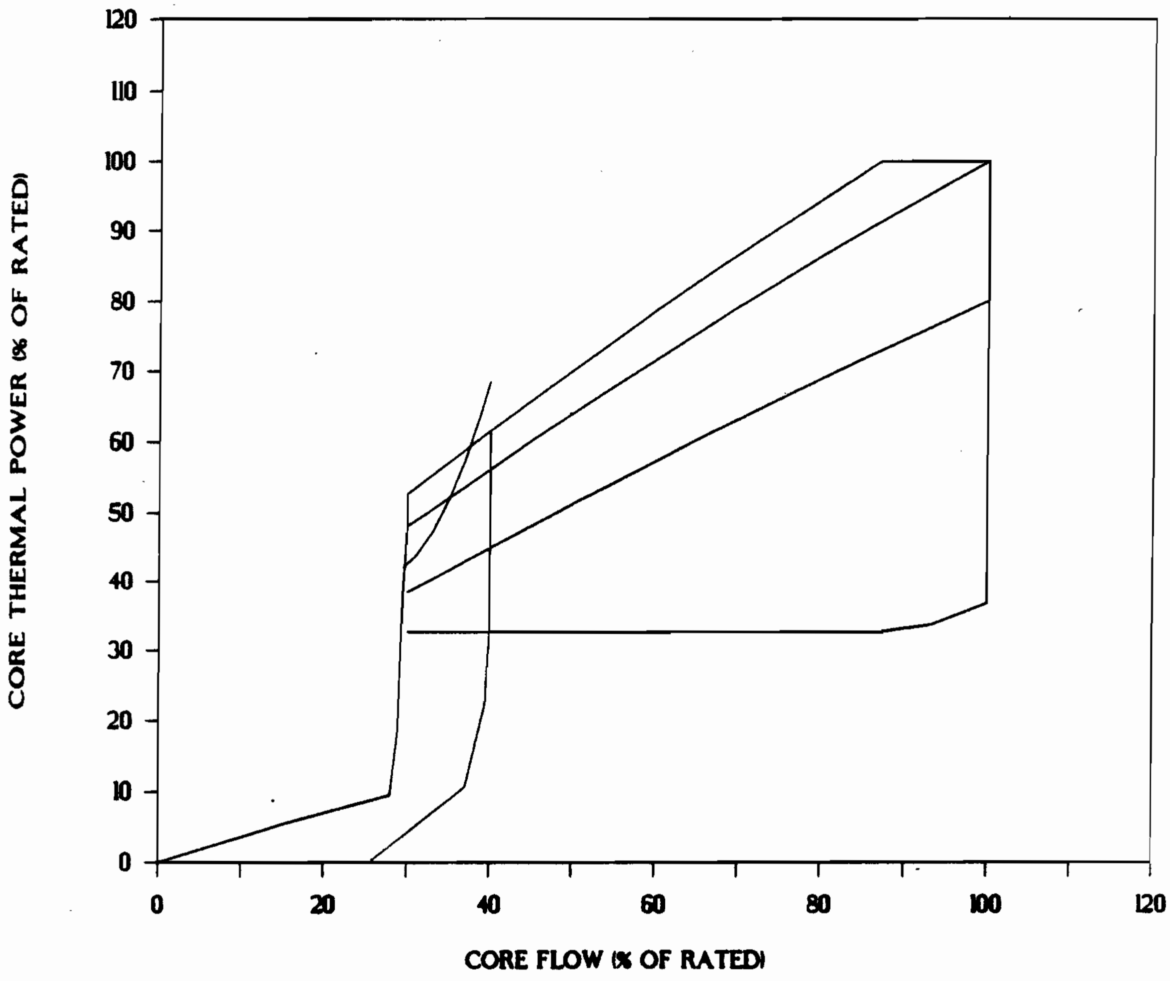

FIGURE A-9. DUANE ARNOLD CYCLE 10 REGION BOUNDARY DEFINITION

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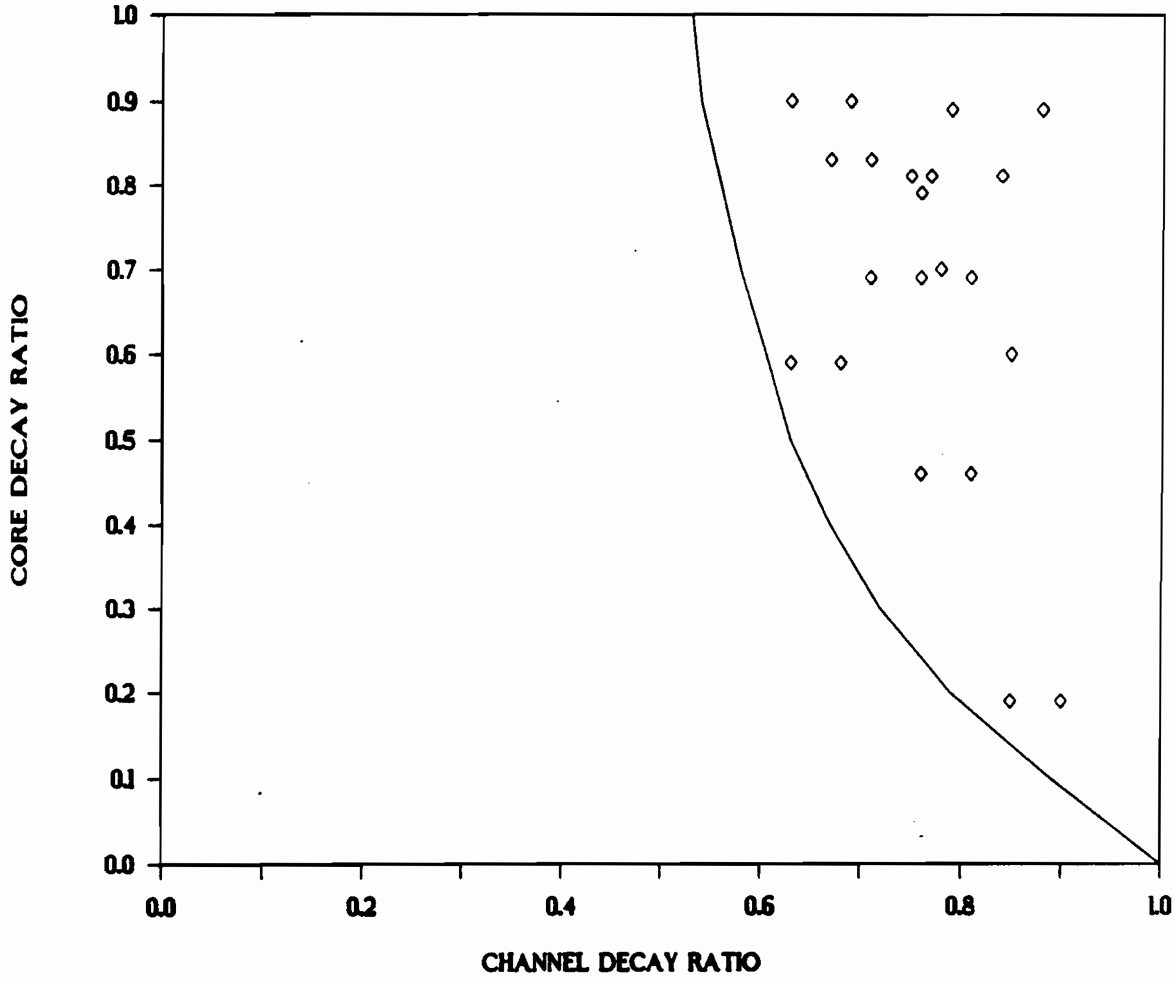

FIGURE A-10. CORE/CHANNEL DECAY RATIOS RESULTING IN CALCULATED REGIONAL OSCILLATIONS

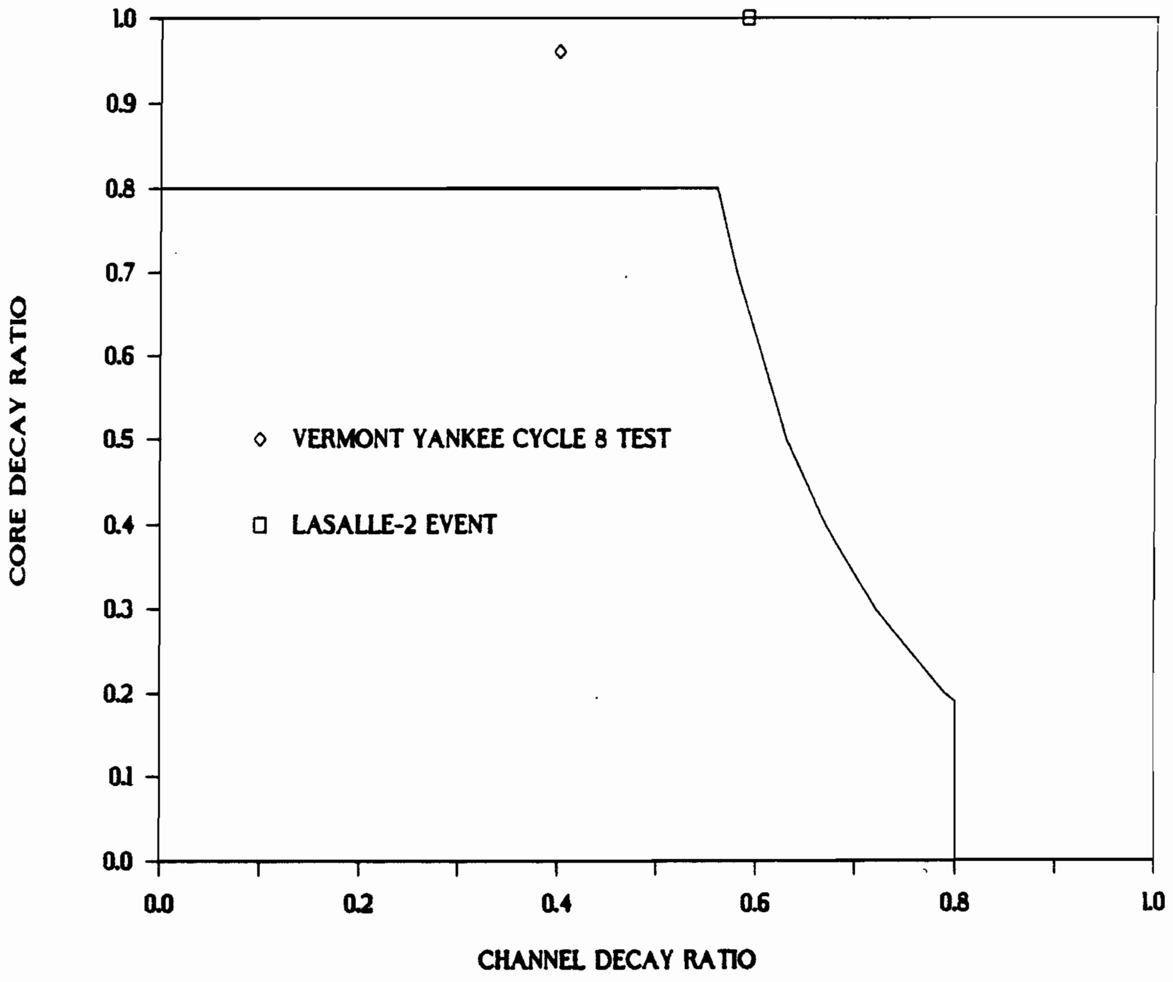

FIGURE A-11. STABILITY CRITERIA

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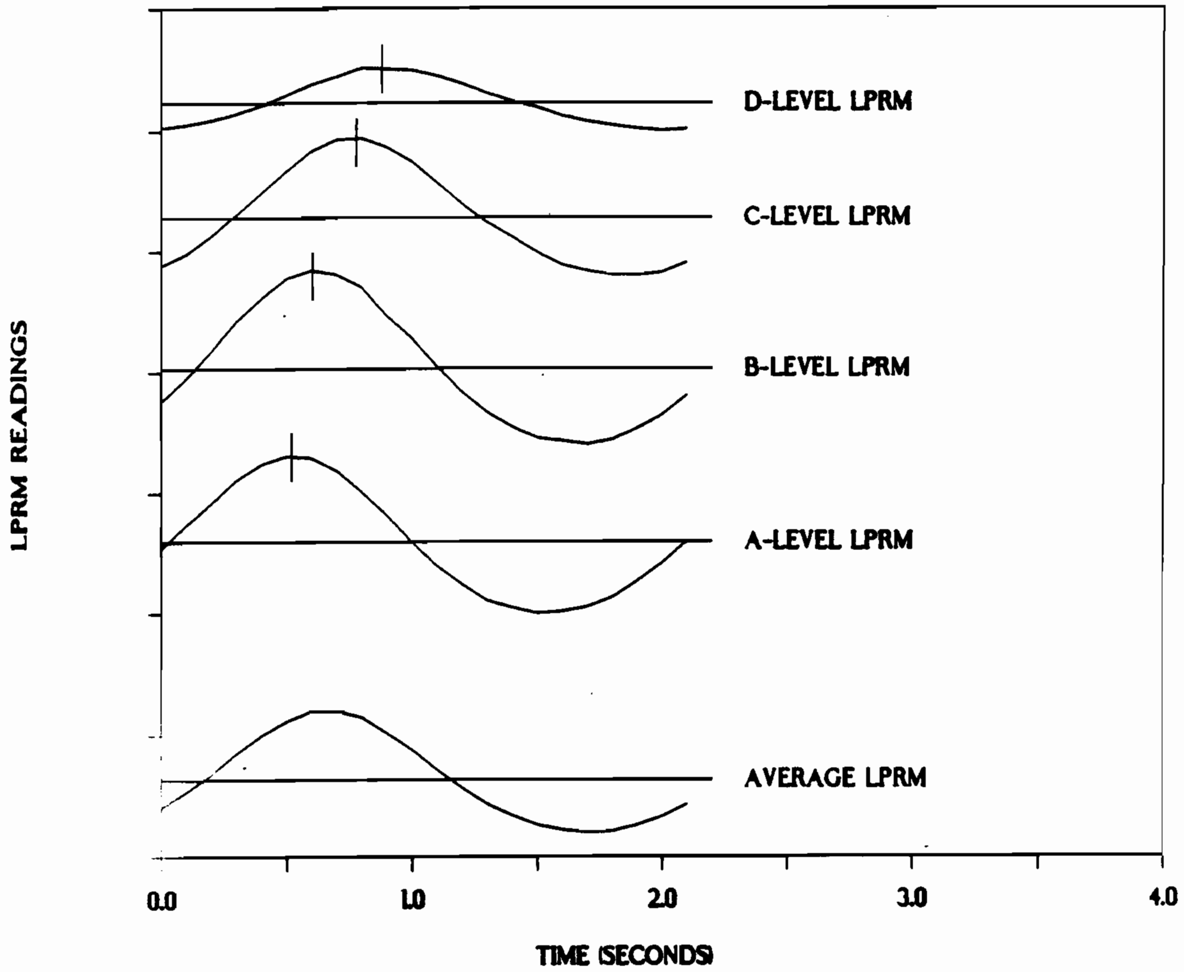

FIGURE A-12. AXIAL VARIATION IN LPRM READINGS DURING AN INSTABILITY

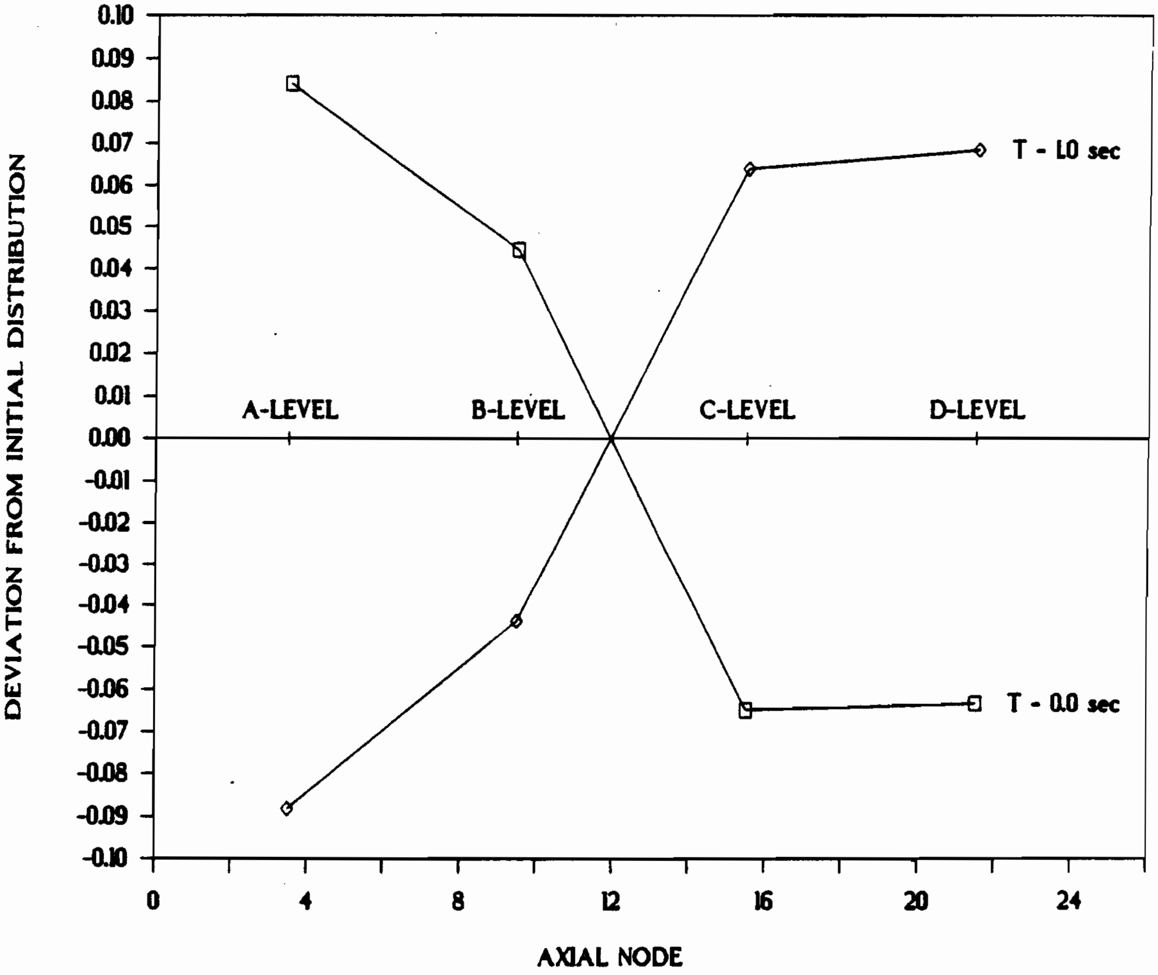

FIGURE A-13. CHANGE IN AXIAL POWER SHAPE DURING AN INSTABILITY

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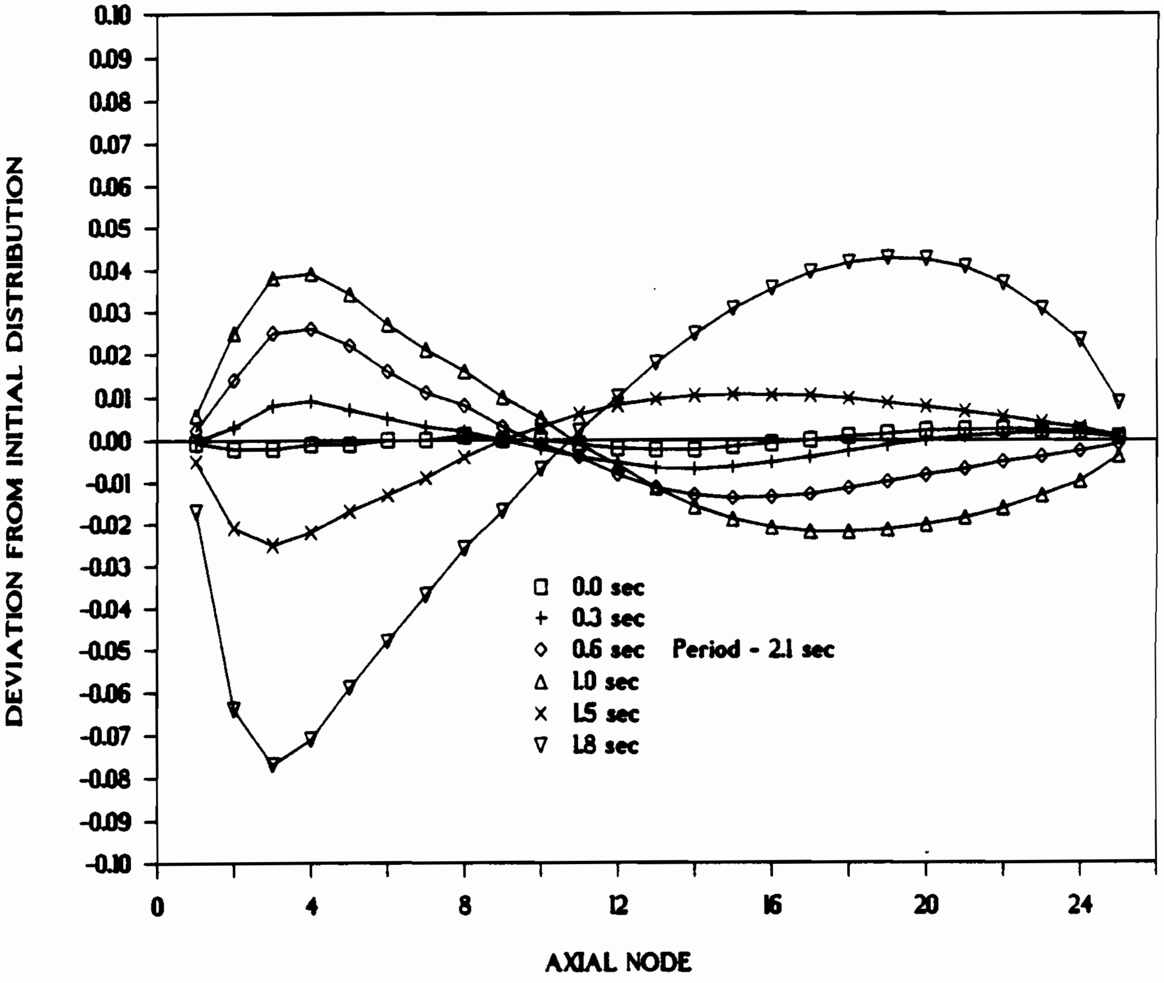


FIGURE A-14. TRAC-G PREDICTION OF THE AXIAL HARMONIC DURING AN INSTABILITY

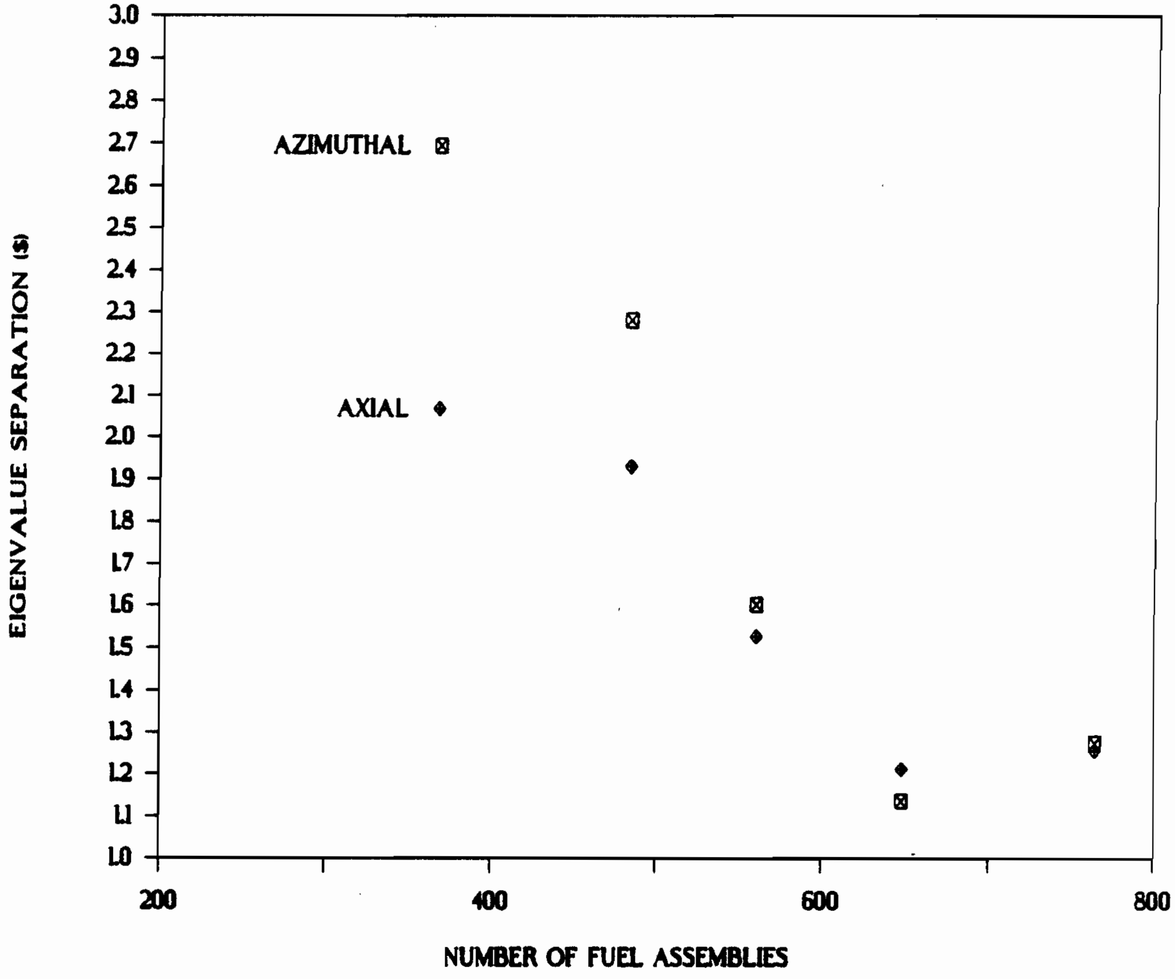


FIGURE A-15. EIGENVALUE SEPARATION AS A FUNCTION OF CORE SIZE

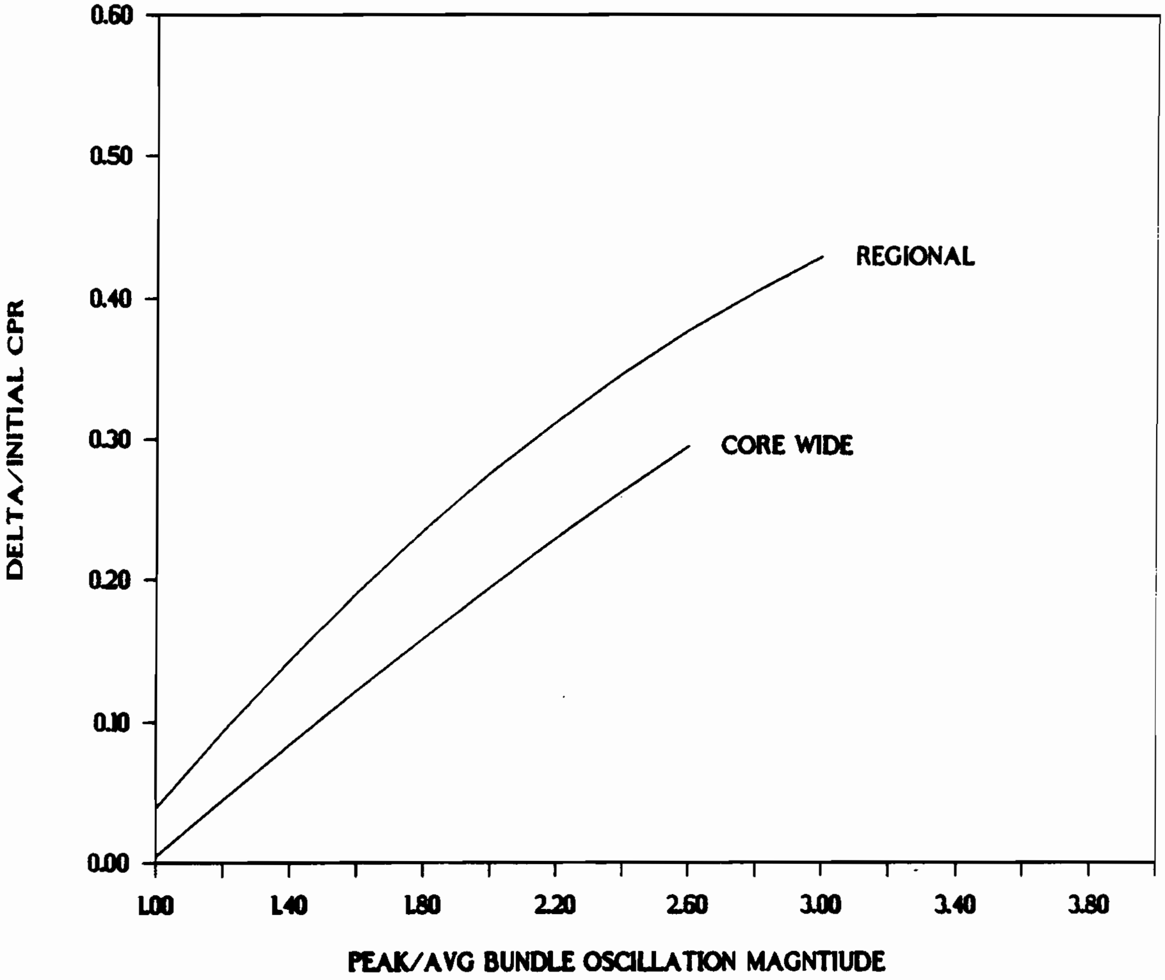


FIGURE A-16. MCPR PERFORMANCE DURING DIFFERENT OSCILLATION MODES

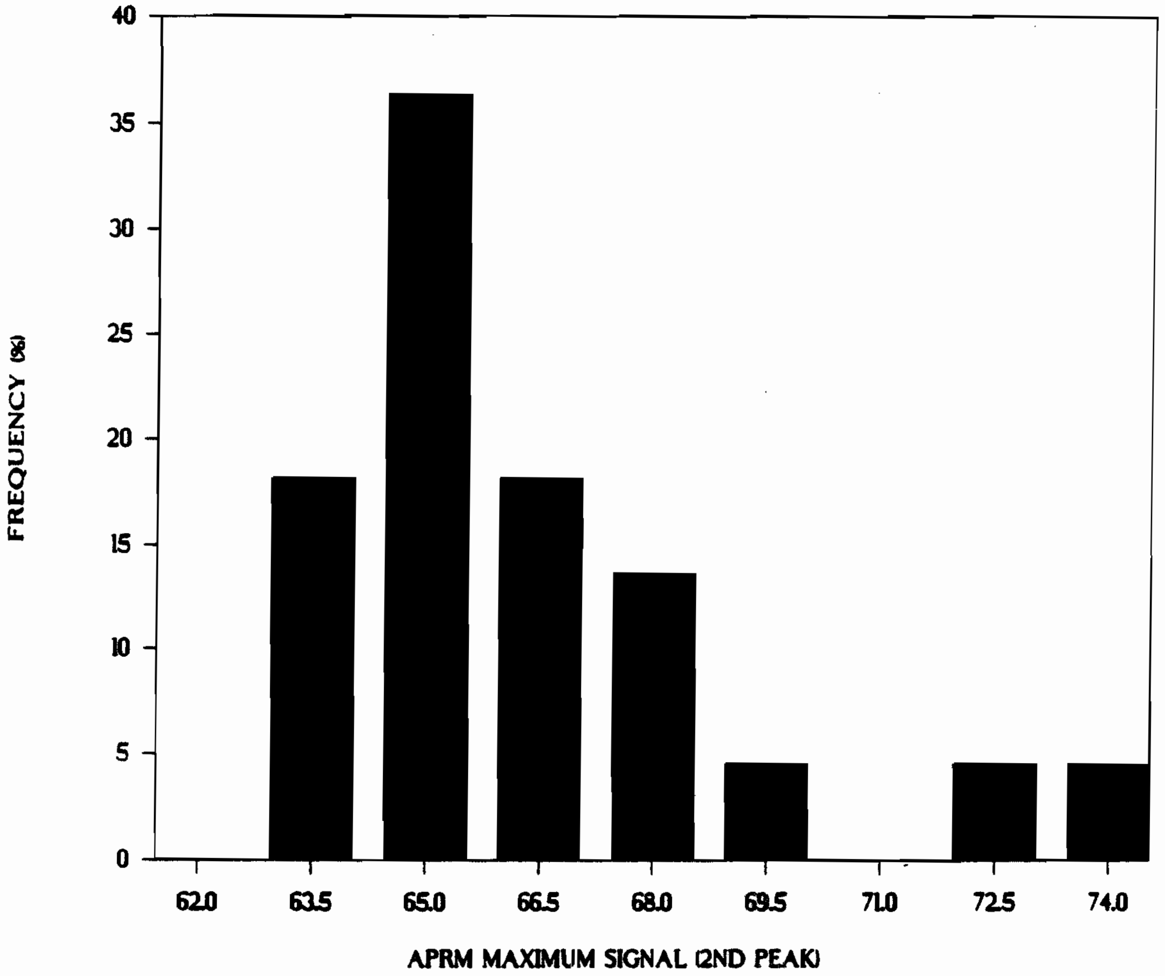


FIGURE A-17. EXAMPLE SETPOINT OVERSHOOT DISTRIBUTION

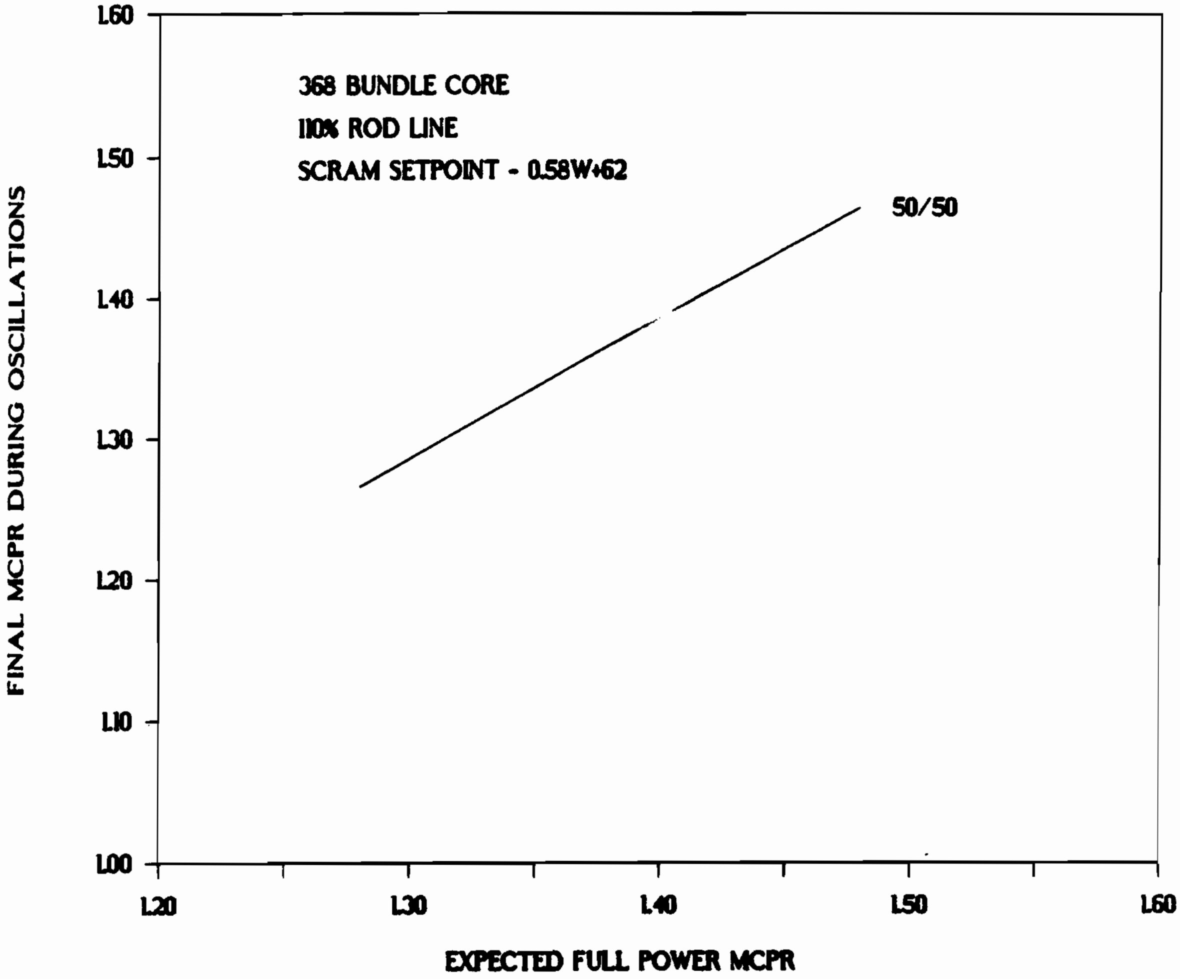
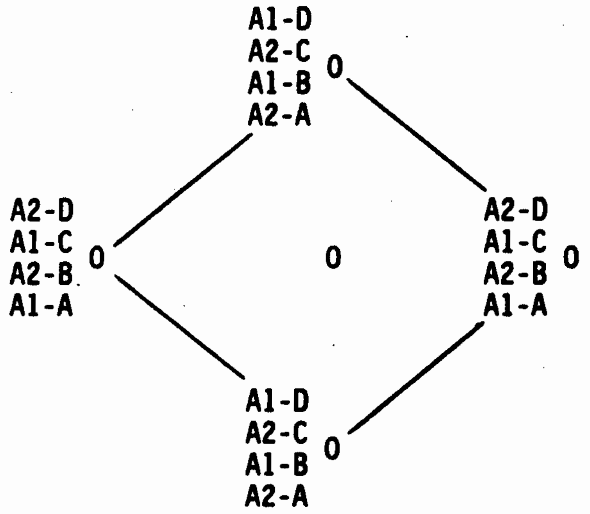
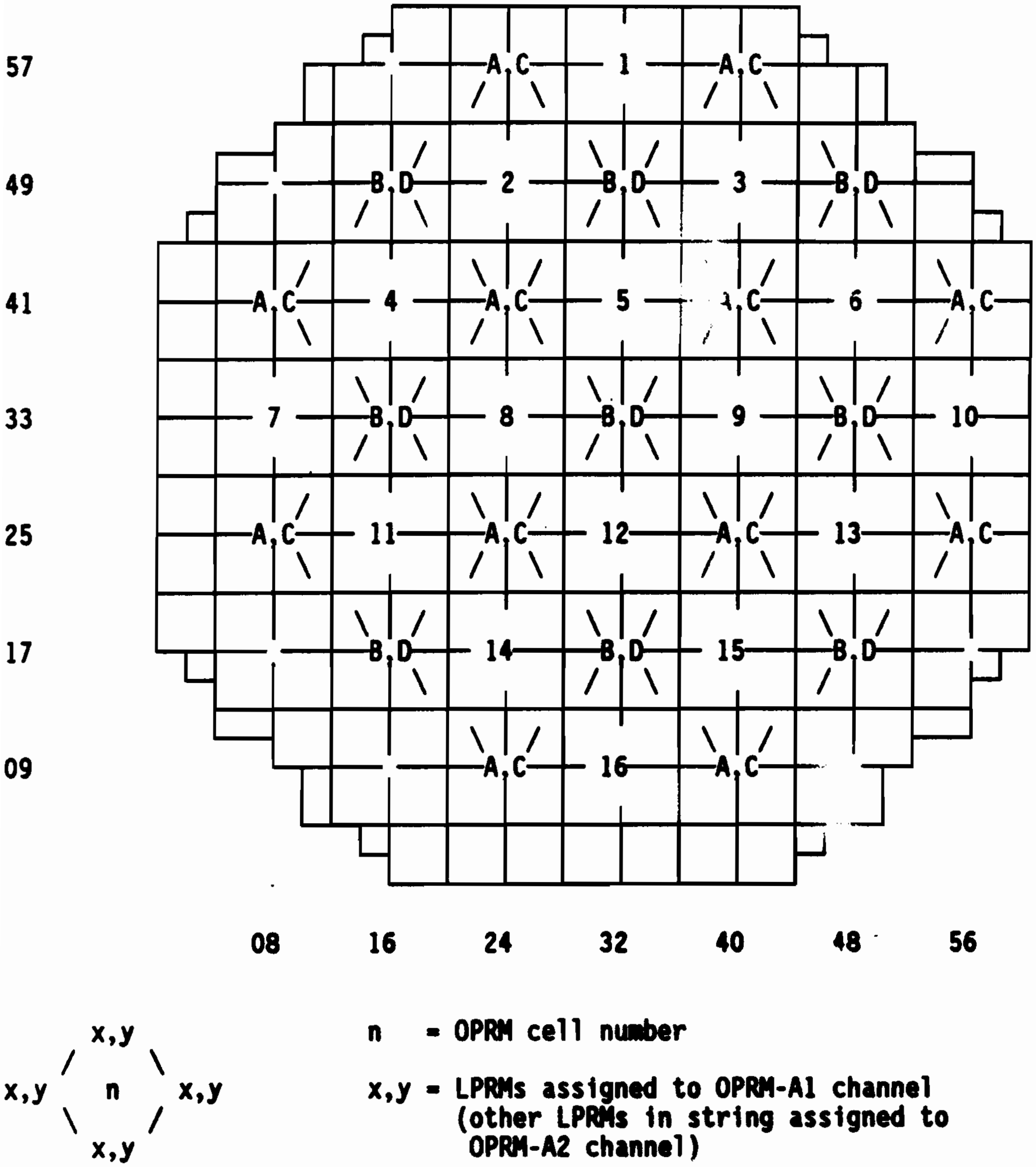


FIGURE A-18. SENSITIVITY TO INITIAL MCPR DURING REGIONAL OSCILLATIONS



0 = LPRM string
A, B, C, D = LPRM detector levels (A is bottom detector)
A1, A2, B1, B2 = OPRM channel assigned to respective LPRM detector

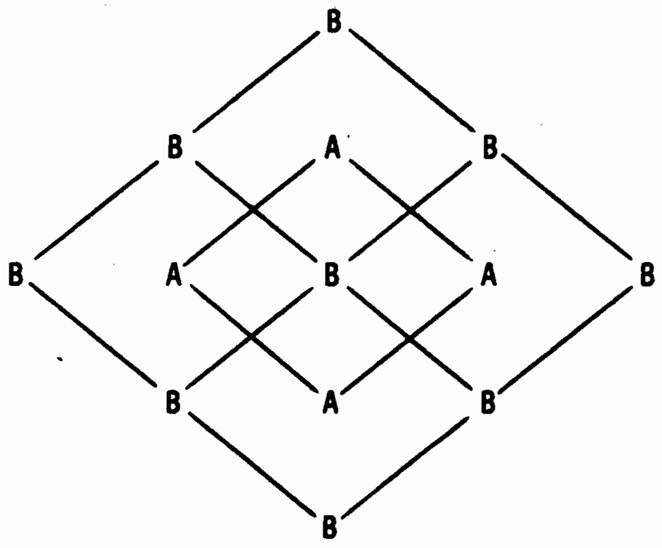
FIGURE A-19. BASIC "DIAMOND" ASSIGNMENT SCHEME



n = OPRM cell number

x,y = LPRMs assigned to OPRM-A1 channel (other LPRMs in string assigned to OPRM-A2 channel)

FIGURE A-20. 764 BUNDLE LPRM ASSIGNMENTS TO OPRM A1(A2)



Note: A and B indicate LPRM string locations.

FIGURE A-21. EXAMPLE OF A AND B DIVISION OPRM OVERLAP

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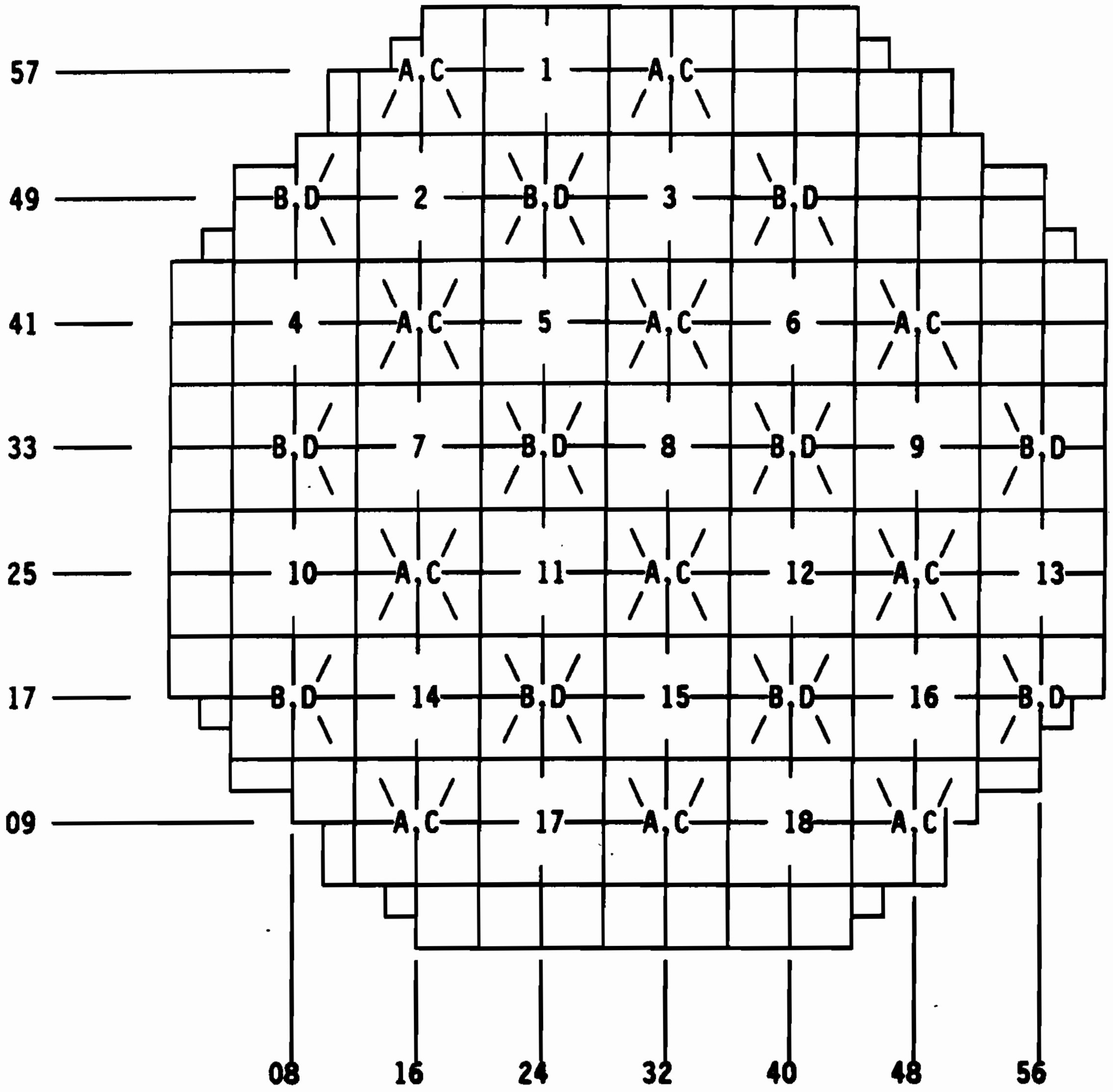
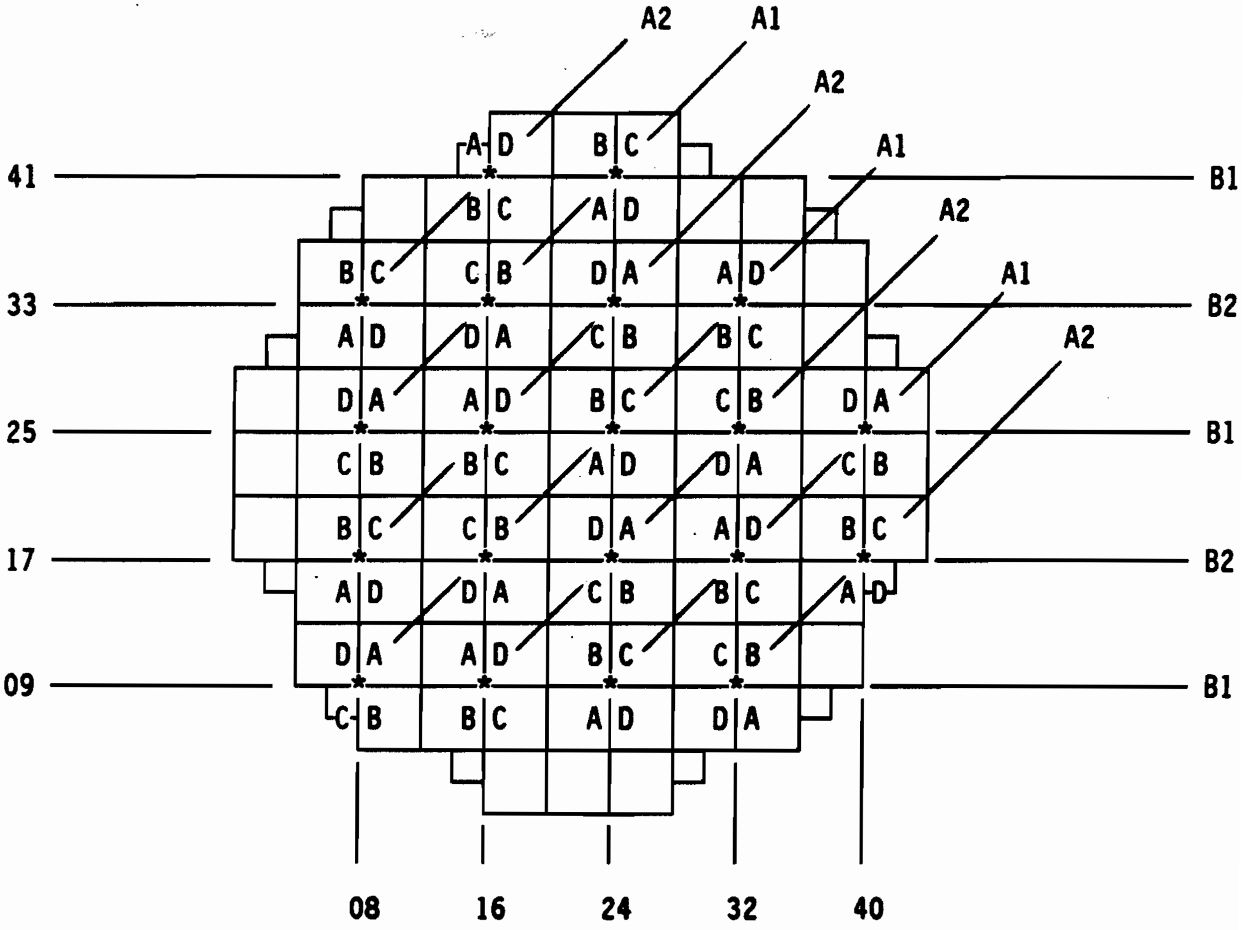


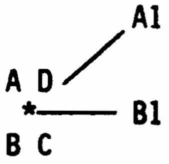
x,y
/ \
x,y n x,y
\ /
x,y

n = OPRM cell number

x,y = LPRMs assigned to OPRM-B1 channel (other LPRMs in string are assigned to OPRM-B2 channel)

FIGURE A-22. 764 BUNDLE LPRM ASSIGNMENTS TO OPRM B1(B2)

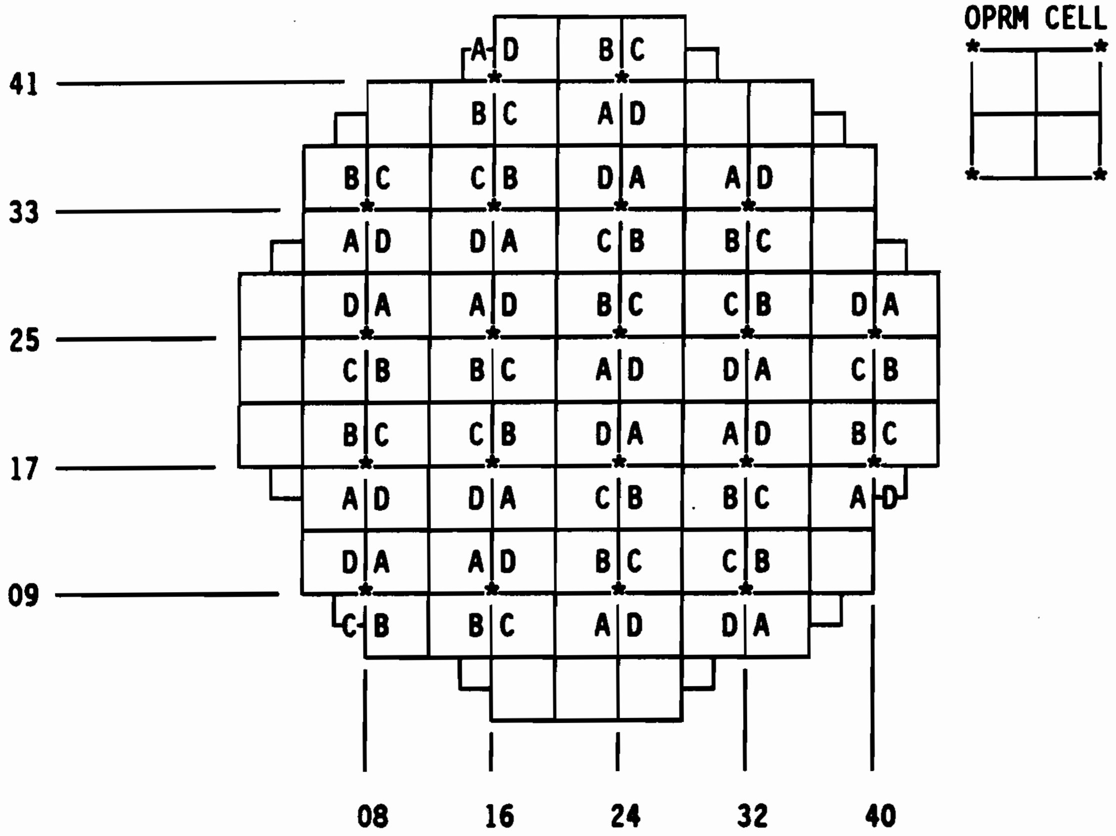




Upper left/lower right letter = Input for OPRM Channels identified (A1/B1 in example)

Upper right/lower left letter = Input for OPRM Channels not identified (A2/B2 in example)

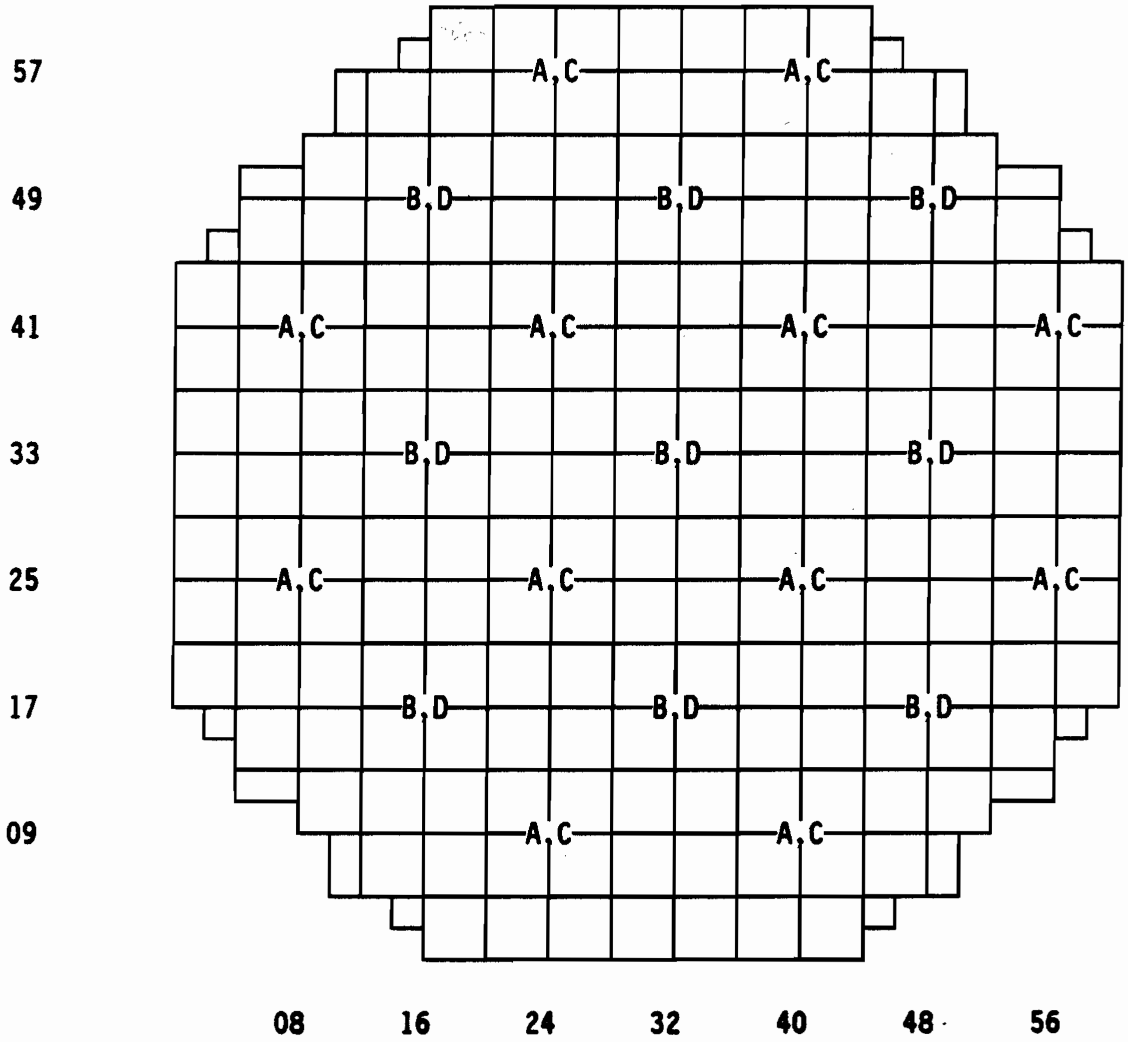
FIGURE A-23. SMALL CORE LPRM ASSIGNMENT SCHEME - TRIANGLE DESIGN



A|B
-*- LPRMs providing input to OPRM Channels A1, A2, B1, and B2
D|C

Upper left letter = Input for OPRM Channel A1
Lower left letter = Input for OPRM Channel B1
Lower right letter = Input for OPRM Channel A2
Upper right letter = Input for OPRM Channel B2

FIGURE A-24. SMALL CORE LPRM ASSIGNMENT SCHEME - SQUARE DESIGN



x,y = LPRMs assigned to OPRM-A1 channel
(other LPRMs in string assigned to
OPRM-A2 channel)

Total number of A1 and A2 cells = 21

FIGURE A-25. 764 BUNDLE LPRM ASSIGNMENTS TO OPRM-A1 FOR THE 2 LPRMs = 1 CELL EXAMPLE

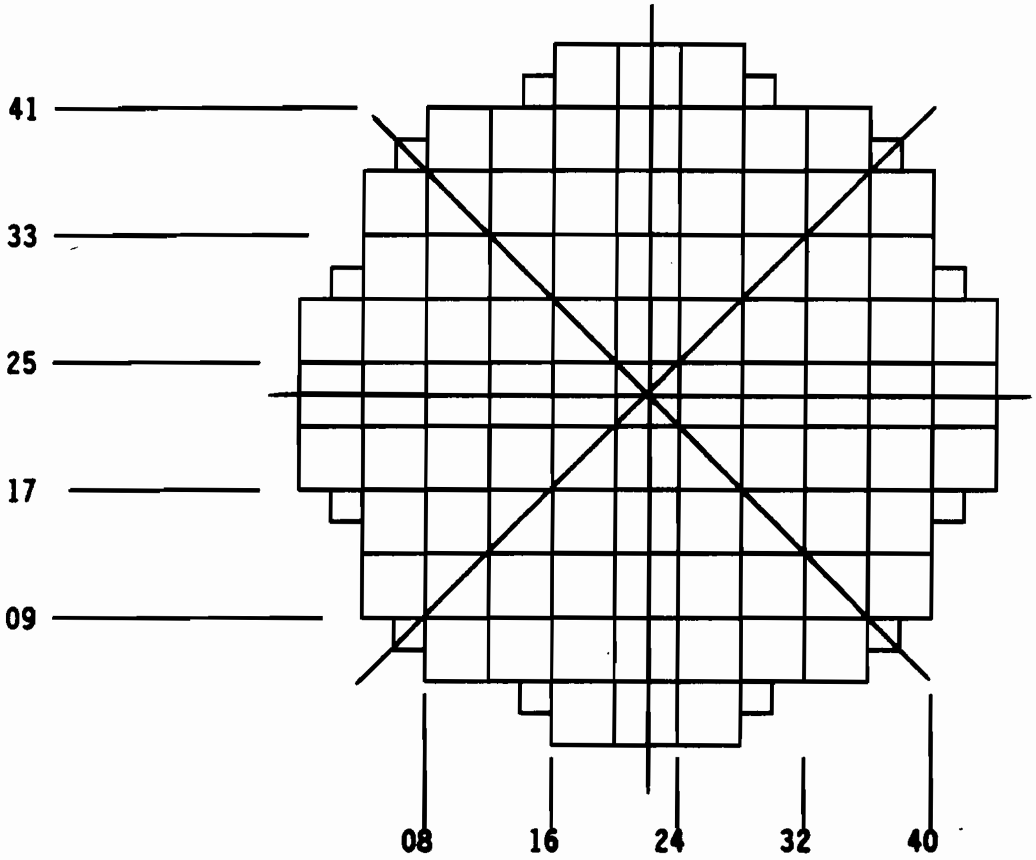


FIGURE A-26. SMALL CORE OCTANT BOUNDARIES

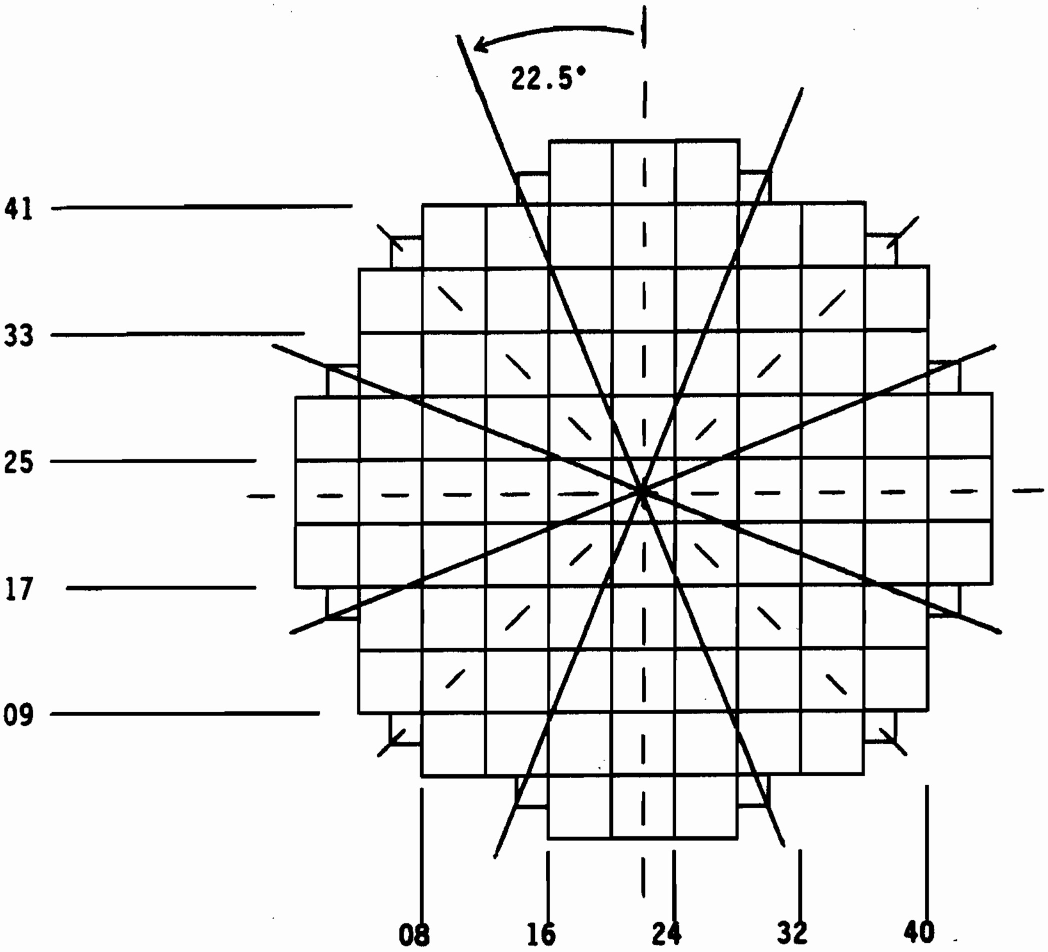
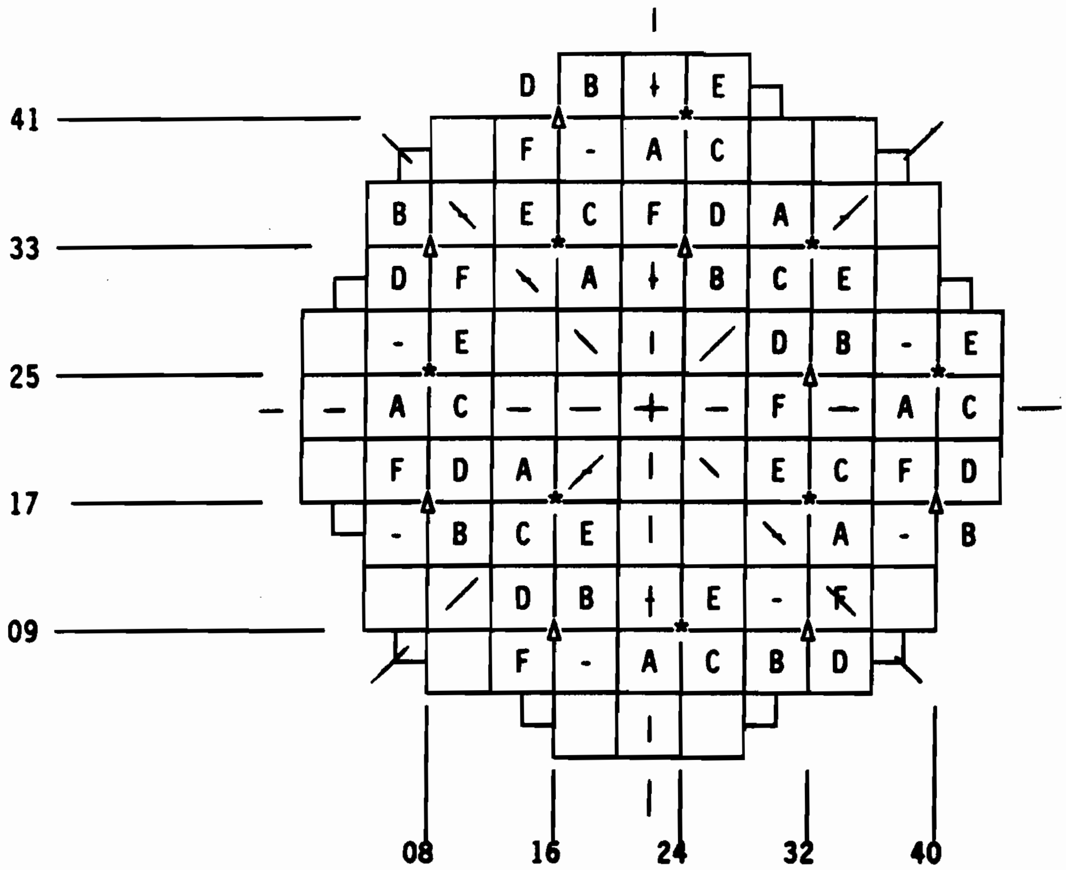
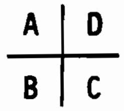


FIGURE A-27. SMALL CORE ALTERNATIVE OCTANT BOUNDARIES





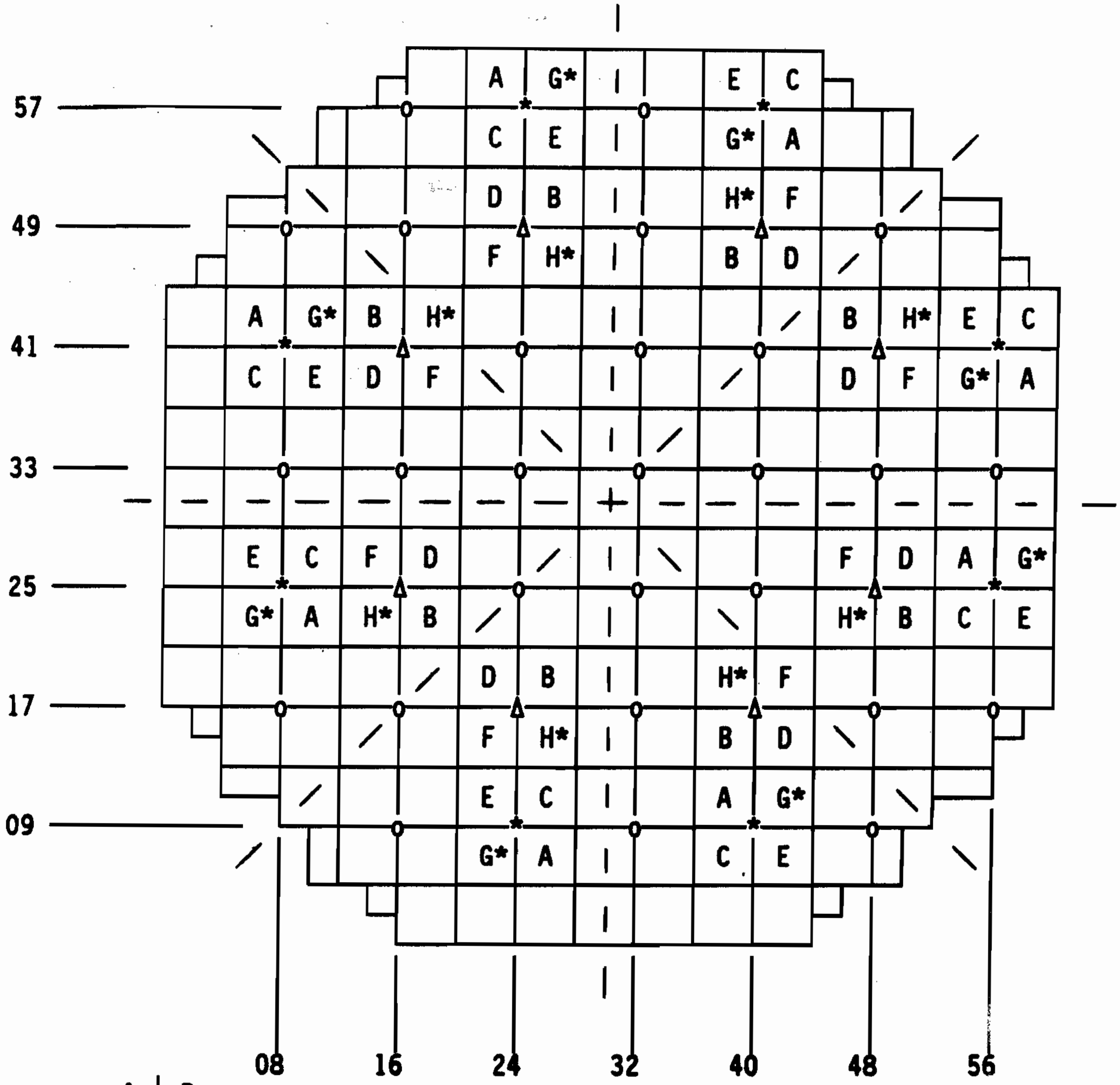
LPRMs providing input to LBS channels

Upper left letter = LBS Channel Assignment for LPRM "A" (bottom)
Lower left letter = LBS Channel Assignment for LPRM "B"
Lower right letter = LBS Channel Assignment for LPRM "C"
Upper right letter = LBS Channel Assignment for LPRM "D" (top)

* = RPS "A" LPRM String

Δ = RPS "B" LPRM String

FIGURE A-28. SAMPLE SMALL CORE LBS ASSIGNMENT SCHEME



A | D
B | C

LPRMs providing input to LBS channels

Upper left letter = LBS Channel Assignment for LPRM "A" (bottom)
Lower left letter = LBS Channel Assignment for LPRM "B"
Lower right letter = LBS Channel Assignment for LPRM "C"
Upper right letter = LBS Channel Assignment for LPRM "D" (top)

G*, H* for BWR/6 only, all other plants have no assignments for these LPRMs

* = RPS "A" LPRM String

Δ = RPS "B" LPRM String

FIGURE A-29. SAMPLE LARGE CORE LBS ASSIGNMENT SCHEME

APPENDIX B

OSCILLATION DETECTION ALGORITHMS

Detection and suppression systems rely on the recognition of oscillations by monitoring LPRM signals. An evaluation of the LPRM signals (or groups of LPRM signals) that determines whether the signal variations are indicative of an instability is called an "oscillation detection algorithm". These algorithms are important in ensuring the early detection of instabilities and subsequent initiation of an ASF before exceeding the MCPR Safety Limit. However, the algorithms must also be able to discriminate against spurious signals to avoid unnecessary initiations of the ASF.

Stability-related neutron flux oscillations in a BWR exhibit known characteristics (e.g., a dominant frequency in the range of 0.3 to 0.7 Hz) that will be used in the design of trip algorithms. As the stability threshold is crossed, oscillations begin and grow to a limit cycle (constant oscillation magnitude). The rate of growth of the oscillations is determined by the instability of the conditions, how rapidly the condition is entered, and also perturbations in the system. In general, the approach to a limit cycle in the magnitude range of interest (prior to trip) is relatively gradual. The periodic nature of oscillations and the fact that oscillation growth must occur before any fuel impact is possible allows an algorithm to be designed that will be able to discriminate between stability-related neutron flux oscillations and other neutron flux variations that are expected to occur in the plant.

The algorithms monitor the trip system channel responses and provide a trip signal if a growing oscillation with sufficient magnitude is detected. The trip system channels may be comprised of individual LPRM signals or groups of signals called cells. Each individual LPRM signal or cell value is evaluated against the algorithm.

The determination that the channel response is oscillating requires the calculation of a time dependent signal average. The characteristic frequency of the oscillations can also be used to confirm that the oscillation peaks and minima are occurring at intervals which are consistent with the expected frequency range. The determination that the oscillation magnitude is growing requires at least two peaks of oscillation before a trip is actuated. These features have the potential to introduce time delays in the trip logic. Any time delay caused by an algorithm is factored into the basis for the trip setpoints. In general, various oscillations are evaluated relative to the oscillation magnitude reached when the logic initiates a trip. A range of oscillation growth rates is evaluated to confirm that the setpoints are adequate to protect the MCPR Safety Limit.

The basic approach to establishing trip system setpoints is first to determine an acceptably low setpoint such that expected plant evolutions do not result in initiation of an ASF and then confirm that the setpoint provides margin to the MCPR Safety Limit. Therefore, evaluation of plant operating data against potential trip algorithms is the first step in the determination of the setpoints. Basic characteristics of oscillations are already known from test data and operating experience. The trip algorithm can be conceptually designed based on this information. Digitally recorded plant data during various expected plant maneuvers are then analyzed by the trip algorithm to determine the margin to trip for these transients. Desired trip margins are established based on trip avoidance and previous experience with other trip systems.

In addition to the expected plant evolutions that are not required to initiate a trip, digitally recorded data from BWR instability events are evaluated using the trip algorithms. This evaluation confirms that the trip algorithm can accurately identify the occurrence of oscillations and readily detect the necessary characteristics for initiating a trip. The following section discusses examples of oscillation detection algorithms.

B.1 HIGH-LOW-HIGH DETECTION ALGORITHM

The oscillation recognition algorithm is intended to discriminate between true stability-related neutron flux oscillations and other flux variations that may be expected during plant operation. The algorithm design has two primary objectives. The first is to provide a sufficiently low amplitude trip setpoint such that margin is maintained to the MCPR Safety Limit. Second, the algorithm must be capable of identifying stability-related neutron flux oscillations and discriminating against "false" signals from other expected plant evolutions. This design objective is essential for maintaining reliable power operation and, simultaneously, minimizing unnecessary challenges to the ASF. It is not the objective of the algorithm to avoid tripping due to single failures associated with the neutron monitoring system. For example, the redundancy in the OPRM channel design (i.e., multiple OPRM cells per channel, and four OPRM channels which can be used in a one-out-of-two-taken-twice trip logic) provides the required single failure protection.

To provide a "smart" algorithm, some information must be known about the characteristics of oscillations as well as other expected variations in sensed neutron flux. These characteristics form the basis for selecting the specific algorithm features. The following is a discussion of some of the characteristics that are considered important in the design of the algorithm.

The natural frequency of density wave oscillations in a BWR is directly related to the void transport time. This parameter is well known and does not significantly vary from plant to plant. The natural frequencies that have been observed during instabilities at jet pump BWRs are listed in Table B-1. The expected range of oscillation frequencies is 0.4 to 0.6 Hz based on the plant data. These instability events and tests cover a wide range of power, flow, power distributions, and core inlet subcooling conditions. For conservatism, the algorithm was designed to protect against oscillations with a frequency in the range of 0.3 to 0.7 Hz.

At the onset of an instability event, the oscillations are very nearly sinusoidal in time with a magnitude that dominates the normal steady state noise conditions. Therefore, the oscillations are very "clean" and distinctive and show a smooth trend in time. The increasing magnitude of oscillations can be expressed in the form of a decay ratio or growth rate. Oscillations that are growing initially have a relatively constant growth rate and then reach an equilibrium magnitude (i.e., limit cycle). Examples of limit cycle and growing oscillations are shown in Figures B-1 and B-2.

BWRs exhibit normal neutron flux noise that is the result of perturbations in the reactor system which affect the void reactivity. The noise shows the same dominant frequency as an instability. Plant LPRM data for a condition with a decay ratio of approximately 0.8, as determined by noise analysis, are shown in Figure B-3. Although the same characteristic frequency is evident in the noise signal, the coherence of the signal in time is not as high as for the unstable conditions. The noise signal does exhibit periods of growing amplitude for several successive peaks, although the magnitude is limited.

The neutron flux response during expected plant transients (pressure perturbation and recirculation pump start) is shown in Figures B-4 and B-5. The initial portion of the transient shows an oscillatory behavior with a decaying trend. This type of response is expected for short duration events which introduce a step or rapid change in reactivity. It is the timing and decaying trend of these transients that is important with respect to the algorithm design.

Based on the described characteristics of oscillations and expected plant transients/maneuvers, an initial design of the algorithm has been selected. The basic design concept is to evaluate the signal (e.g., LPRM or OPRM cell) relative to its time-averaged value to determine any oscillatory behavior. The known frequency range of the oscillations is used to detect successive oscillation peaks and valleys such that peaks occurring too close together or too far apart in time are screened. To avoid ASF initiations for initially large amplitude perturbations that decay in time, two successive peaks will be required to produce a trip, with the second peak larger than the first by a specified amount. A maximum trip level is also provided for the second peak.

The signal (e.g., LPRM or OPRM cell) value is filtered to remove high frequency noise components relative to the oscillation frequency (> 5 Hz). The resulting filtered signal is referred to as the conditioned signal value. The conditioned signal value is then filtered (approximately a six second time constant) to produce a time-averaged value indicative of the thermal power in the region where the signal measurement is taken. This value is used as a baseline for comparison with the conditioned value. A relative signal value is then determined by dividing the conditioned signal value by the time-averaged value. This relative signal value is then used in the algorithm.

The relative signal value (Figure B-6) is first compared to a threshold trip level, S_1 (e.g., $S_1 = 1.10$, which corresponds to an instantaneous signal value 10% higher than the time-averaged value). If the threshold trip level is exceeded, timers are initialized to begin a search for the first peak (P_1) and also for the next valley. Once S_1 is exceeded, the relative signal value is compared against the minimum threshold, S_2 (e.g., $S_2 = 0.93$). If the signal value goes below the minimum threshold level in the allowable time window, timers are then initialized to begin the search for the next peak. The next peak can now trip the associated channel if the peak exceeds one of two trip setpoints.

If the previous conditions have been met, the relative signal value is compared to a trip setpoint, S_3, which is based on the previously detected peak (P_1). The purpose of the S_3 trip setpoint is to initiate a trip for oscillations with very high growth rates. The S_3 trip setpoint is calculated as:

$$S_3 = (P_1 - 1.0) * DR_3 + 1.0 \qquad \text{(B-1)}$$

where

DR_3 = Growth rate factor for S_3 trip setpoint calculation.

Additionally, the relative signal value is compared against an absolute maximum trip setpoint (S_{max}) to protect against very slowly growing oscillations that have a growth rate less than DR_3. One of the two trip setpoints (S_3 or S_{max}) must be exceeded in the allowable time window for a trip to be initiated. If any of the criteria of the algorithm are not satisfied in the required time intervals, the logic is reset and no trip occurs. The relationship between the various setpoints is shown in Figure B-6.

B.2 PERIOD BASED DETECTION ALGORITHM

An alternative detection algorithm that is based on recognition of the thermal-hydraulic oscillation period can be used to support the microprocessor-based systems. This algorithm is based on the observation that the neutron flux of an unstable core will oscillate with a well defined period and that the neutron flux of a stable core will be characterized by random noise.

Detection of the inception of thermal-hydraulic instability will be confirmed by several consecutive equal periods which will also result in an alarm signal. The oscillation amplitude will then be compared against a trip setpoint. Meeting both conditions (both a sustained period and an increasing signal amplitude) will result in a channel trip signal.

The algorithm is based on the following elements:

(1) Real time signal analysis (i.e., LPRM signal response) with sufficiently high signal sampling and computation frequency (large compared to the thermal-hydraulic oscillation frequency).

(2) Recognition of signal peaks and minima.

(3) Screening of oscillation frequency to be within the expected thermal-hydraulic oscillation range (i.e., 0.3 to 0.7 Hz).

(4) Time-averaging of signals to provide a time-dependent baseline.

The channel alarm and trip functions will be produced as follows:

(1) Identify first two signal peaks and calculate the time interval between them. This time interval is defined as the base period (T_0).

(2) If T_0 is within the expected range (i.e., 1.4 to 3.4 seconds), compare subsequent periods to T_0 with tight tolerance (-10% of T_0). Subsequent

periods consist of the time interval between either two consecutive peaks or two consecutive minima.

(3) If T_0 is confirmed N times (e.g., N=4 to 6), produce channel alarm signal, and

(4) If the last peak is above the trip setpoint (e.g., peak/average = 1.1), produce channel trip signal.

If any of the conditions associated with the period confirmation are not met, T_0 is reset to the latest calculated period (based on either two peaks or two minima). T_0 may be adjusted to reflect the average of all confirmed periods associated with an initial base period. This averaging will eliminate failed confirmations due to period variations caused by discrete sampling intervals. Confirmation of T_0, which already resulted in an alarm (step 3), continues until either confirmation fails (e.g., stable condition, noise disturbance) or the second condition (step 4) is met, leading to channel trip signal. The number of confirmations for the alarm and trip functions may differ.

The algorithm is expected to be very responsive to the inception of instability, and to be able to produce a trip signal at a very low oscillation amplitude with a high level of reliability. This algorithm is expected to provide an early alarm for state conditions with high decay ratio prior to any significant oscillation amplitude growth, and therefore may provide time for appropriate operator suppression action.

This algorithm may be applied to analyze a LPRM signal rather than a LPRM-group averaged signal with no increase in spurious scram probability due to LPRM spikes since the period confirmation requirement will not be met as a result of the LPRM spike and T_0 will reset. LPRM and trip channel redundancy can ensure that no reduction in instability recognition capability will result from a spurious spike in a single LPRM.

Table B-1

OBSERVED OSCILLATION FREQUENCIES

Plant	Power/Flow (%/%)	Frequency (Hz)
Vermont Yankee (1981)	51/31	0.43
Caorso (1983)	52/30	0.48
Leibstadt (1984)	73/40	0.58
Leibstadt (1984)	46/29	0.48
Leibstadt (1984)	56/31	0.46
Leibstadt (1984)	53/30	0.45
Leibstadt (1984)	51/31	0.46
Leibstadt (1984)	46/29	0.46
LaSalle-2 (1988)	45/29	0.45

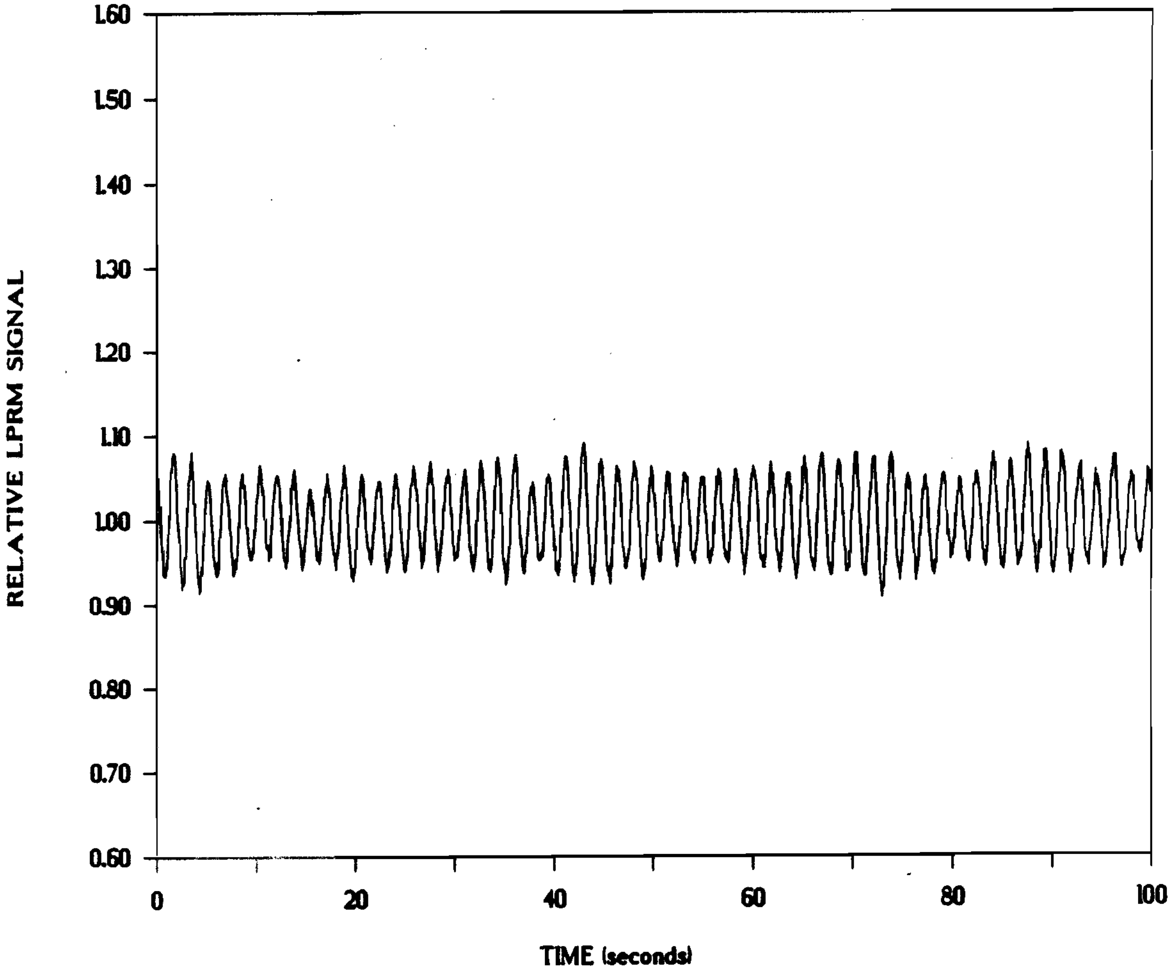


FIGURE B-1. LIMIT CYCLE NEUTRON FLUX OSCILLATION

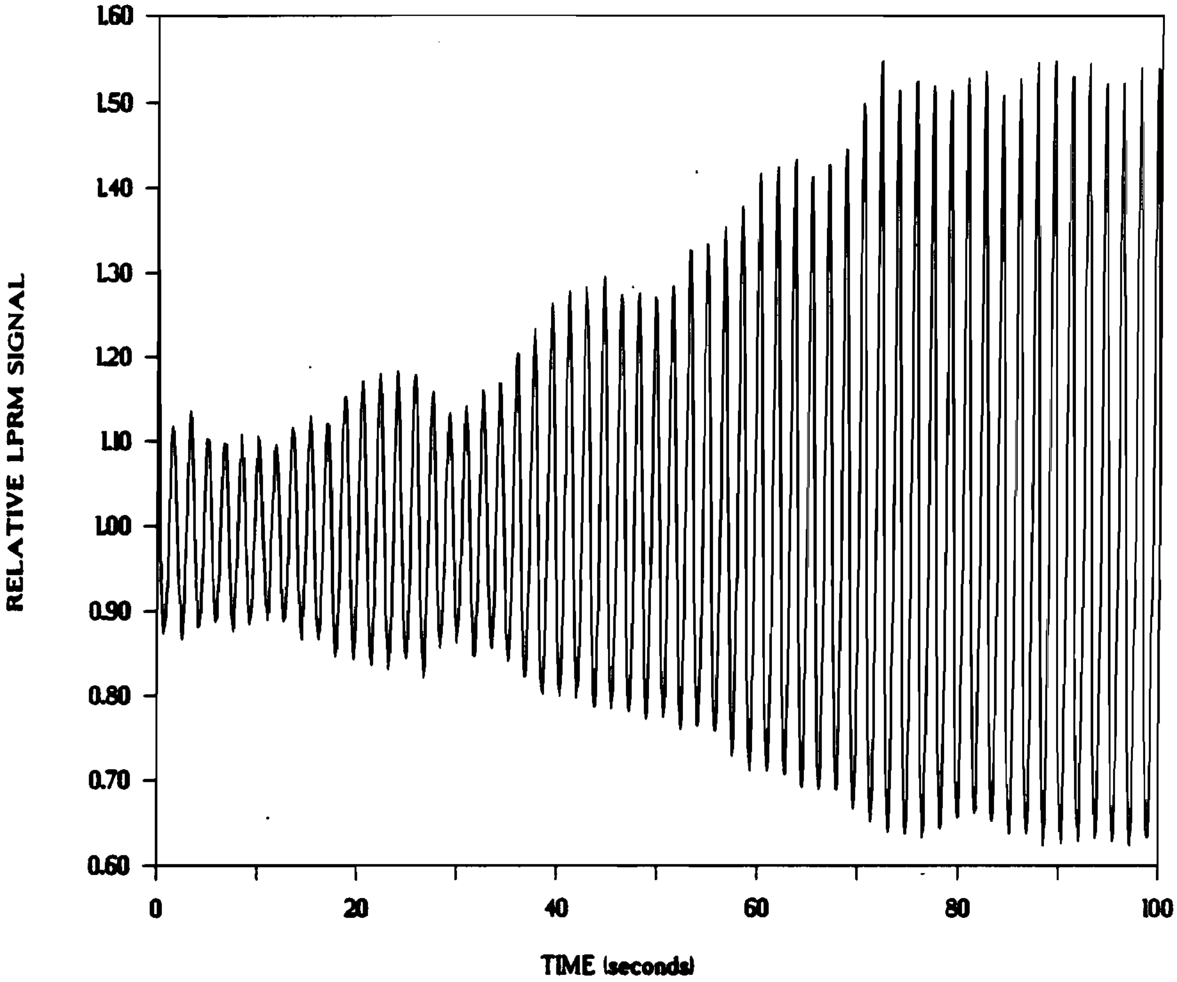


FIGURE B-2. GROWING OSCILLATION SIGNAL

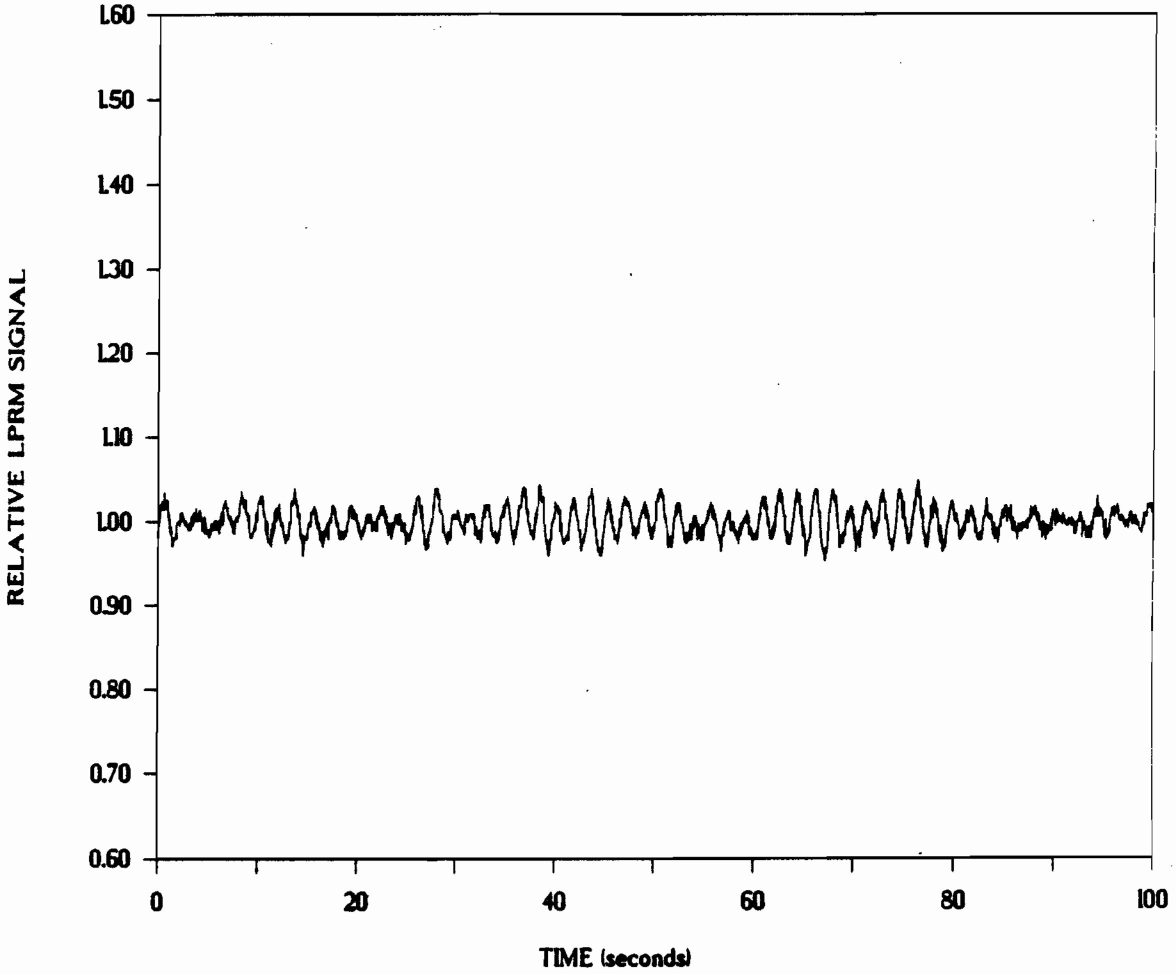


FIGURE B-3. LPRM NOISE RESPONSE - DECAY RATIO = 0.8

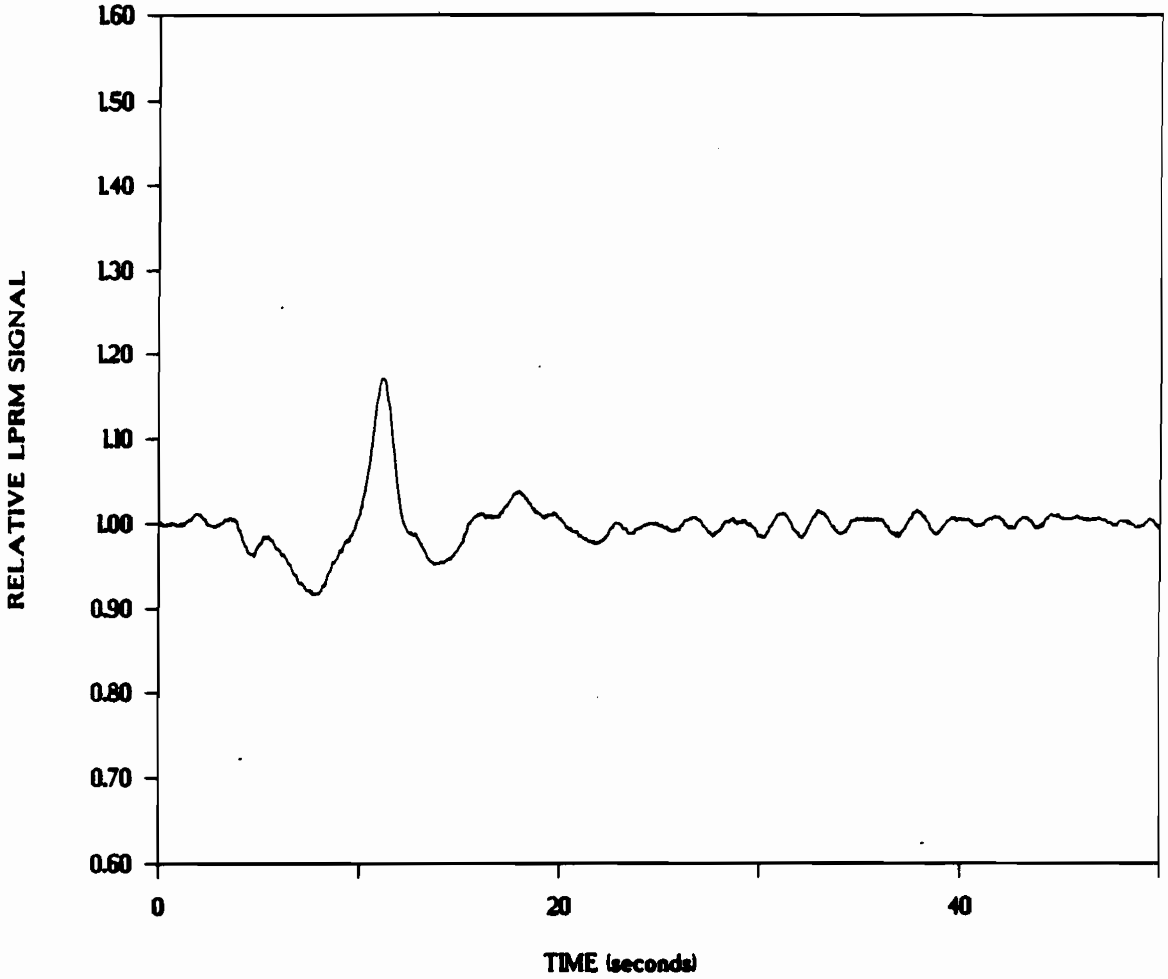


FIGURE B-4. LPRM RESPONSE DURING PRESSURE PERTURBATION

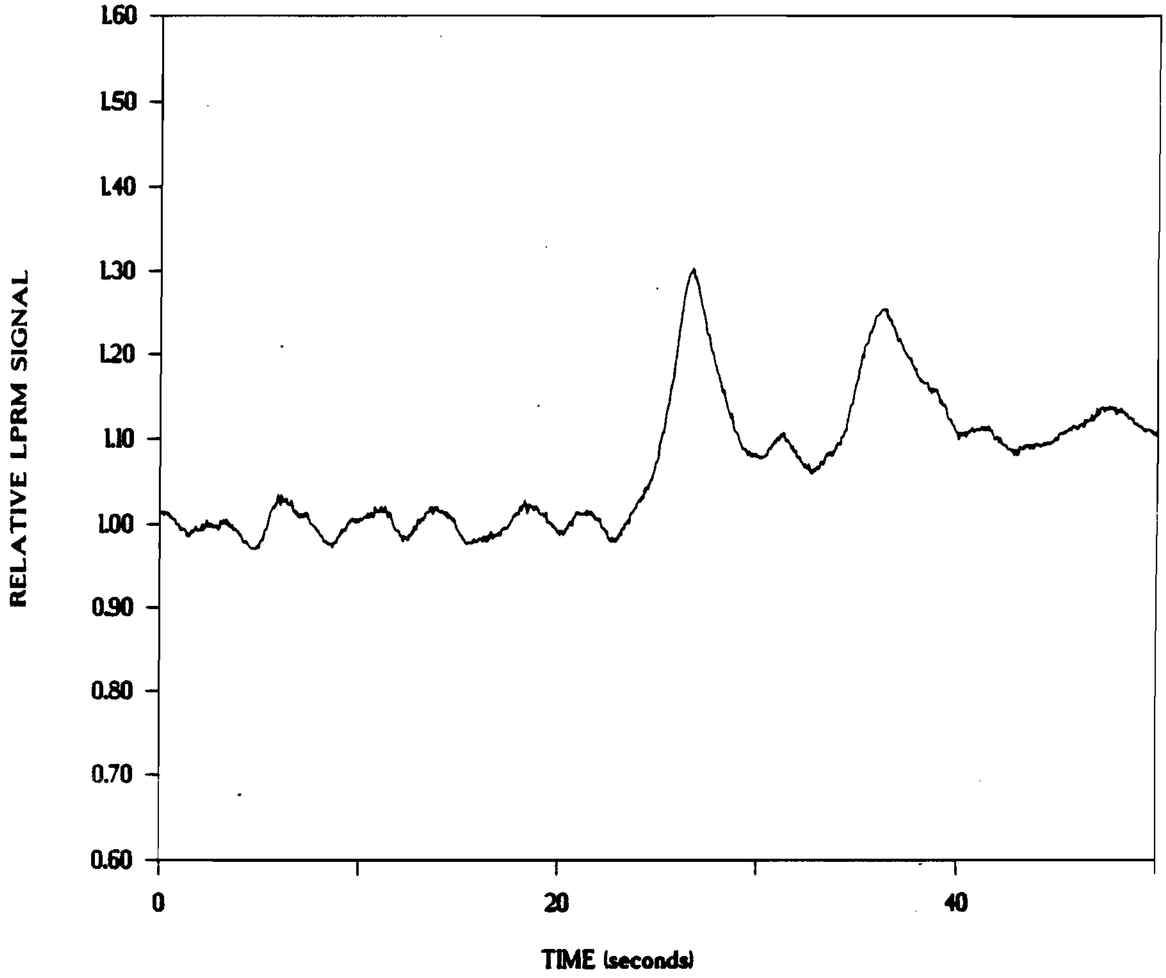


FIGURE B-5. LPRM RESPONSE DURING START OF RECIRCULATION PUMP

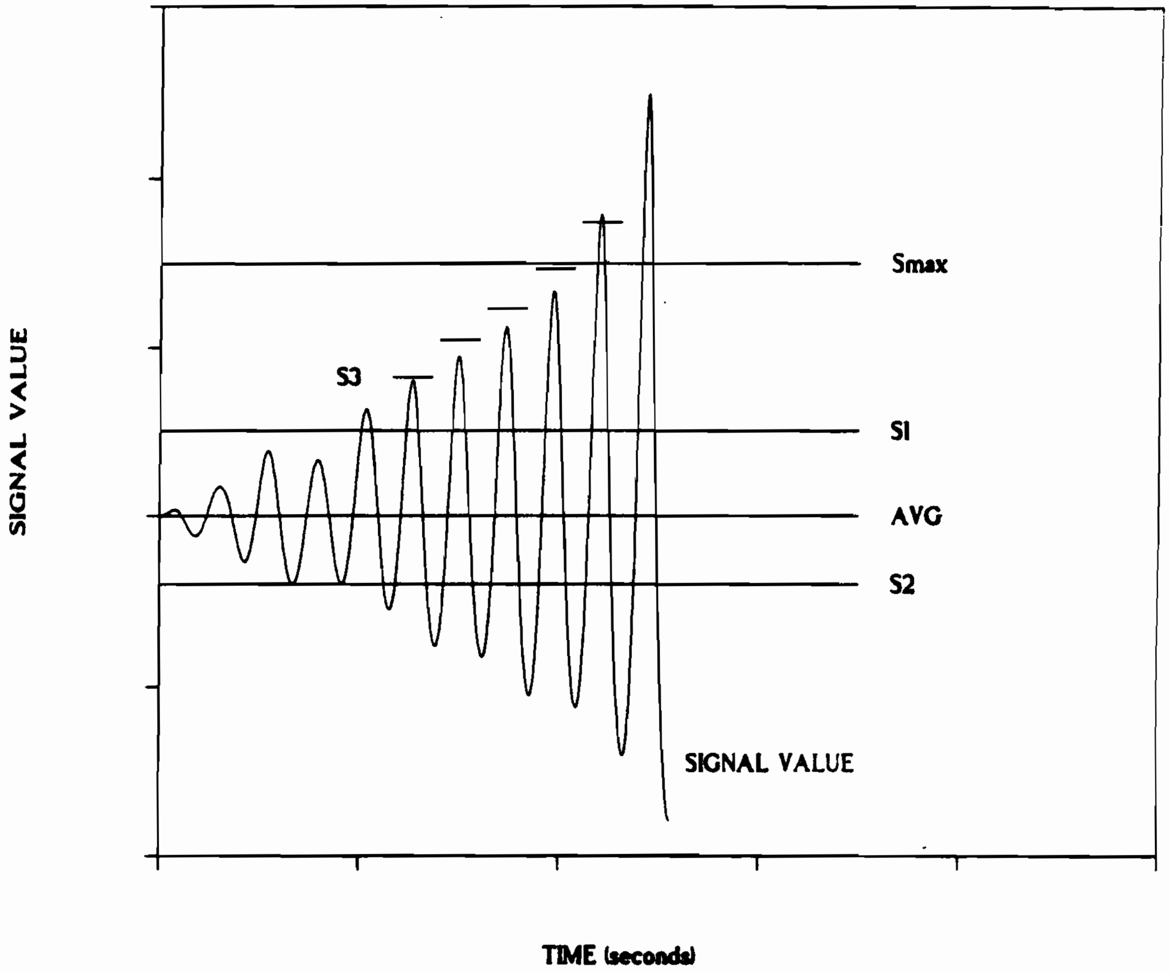


FIGURE B-6. SAMPLE DETECTION ALGORITHM SETPOINTS

FINAL: for review comment

Margin Reduction Estimates for Re-Licensed/Uprated Plants: Hatch Case Study

Report: AWC-105.2001
August 2001

by

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DISCLAIMER

The views expressed in this paper are solely those of the author. They do not necessarily represent the views of the Advisory Committee on Reactor Safeguards (ACRS) or that of the Commission.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Recent electrical power shortages and a more positive public attitude toward nuclear power has lead to industry initiatives at plant life extension, power uprates, and requests for a longer fuel cycle at higher burnup levels. Of the approximately 100 nuclear units currently in operation, it is estimated that upwards of 80 may apply for plant life extensions beyond their current 40 year license. A number of plants have likewise applied for significant power increases, where Table E-1 provides a sampling of recent uprate requests. Although such licensing actions are reviewed by the NRC staff to assure that the current body of regulations are satisfied and that plants continue to operate safely, the Advisory Committee on Reactor Safeguards (ACRS) has expressed concern regarding potential *margin reductions* owing to the compounding effects of such multiple licensing actions, particularly in view of the age of many plants. This report is the subject of that concern.

Table E-1. Sampling of Recent License Amendment Requests for Power Uprates

Plant	Power Uprate	Year Start
Duane Arnold/BWR	15-%	1975
Dresden-2/BWR Dresden-3/BWR	17-% 17-%	1970 1971
Quad Cities-1/BWR Quad Cities-2/BWR	17-% 17-%	1973 1973
Brunswick-1/BWR Brunswick-2/BWR	15-% 15-%	1977 1975
Clinton/BWR	20-%	1987
Arkansas Nuclear One-2/PWR	7.5-%	1978

A prior study [Ref. A] of operational events for uprated plants indicated potential *synergistic* implications of power uprates when combined with fuel life extensions to higher burnup and plant aging phenomena. Examples cited in that study include control rod insertion problems noted in high-burnup/high-power fuel assemblies for the uprated Wolf Creek plant (uprate/high-burnup synergism), and pipe failure events associated with erosion/corrosion effects for the uprated Callaway-PWR and Susquehanna-BWR plants (uprate/aging synergism). Additionally risk implications have been noted for the 15-% power increase for the Swiss Leibstadt-BWR plant [Ref. B], related to an increase in latent cancers and land contamination stemming from higher fission product inventories at uprated conditions.

Although the agency is moving toward a more risk informed approach to regulation, explicit requirements for risk information to support power uprate applications, or for that matter any licensing action, are minimal. For multiple license actions, say for plant life extension and power increase, or for higher fuel burnup with reduced inspection requirements, there is no regulatory requirement for an integrated assessment of the compounding risk implications of such multiple licensing actions. As discussed by Bonaca [Ref. C], the License Renewal Rule rests on the

4

regulatory principle that a nuclear plant can continue to operate for as long as it complies with its current licensing basis and satisfies the current body of regulations. This approach stems from the regulatory framework that compliance with current regulations provides assurance of adequate protection. Although the license renewal process allows for risk considerations to enter into the review, the use of risk information is an option largely left to the applicant. There is no explicit regulatory requirement to assess potential reductions in "margins" from those specified in the original FSAR, only that design margins not be exceeded. The fact remains however, that at the end of 60 years mechanical components will be closer to their fatigue limits than at the end of the original 40 year license, the reactor vessel will be more brittle and closer to the pressurized thermal shock limit, and so on.

To examine margin reductions for power uprates and plant life extension, a case study was made for the Hatch-BWR plant, since this plant received approval for two power uprates (5-%, 8-%) and is currently under review for license renewal. The impact of power uprates on margins was largely interpreted from consideration of changes in plant thermal-hydraulic conditions as compared pressure/temperature design limits for specific plant components. The margin impact for plant life extension was largely assessed from estimates of fatigue limits for particular passive components.

An increase plant power stems from some increase in coolant enthalpy from the core, achieved by an increase in primary system pressure, temperature, net coolant through-flow, or some combination of thereof. Changes in "margins" for the primary coolant system can thus be assessed from changes to such thermal-hydraulic parameters, as compared to design temperature/pressure limits for the primary pressure boundary. Table E-2 presents a summary of changes in operational conditions and margins to design limits for the Hatch power uprates. Higher main steam-line temperatures and pressures associated with uprated conditions are evident, resulting in some reduction in margin to design limits.

Table E-2. Hatch-1 Operational Margins

Residual Margin = [Design Limit – Value] / Design Limit		
Power Level, MWt	Parameter Value	Residual Margin, %
Main Steam-line Pressure (Design Limit = 1250 psig)		
Original = 2436	1015 psig	18.8
1st Uprate = 2558	1050 psig	16
2nd Uprate = 2763	1050 psig	16
Main Steam-line Temperature (Design Limit = 575 F)		
Original = 2436	546 F	5.04
1st Uprate = 2558	---	---
2nd Uprate = 2763	551 F	4.17

The most notable change in component margins for power uprates was found to be associated with predictions for design basis accidents (DBA), such as under loss-of-coolant accidents (LOCA). Table E-3 summarizes DBA-LOCA stress predictions for various Hatch-1 reactor vessel components. A stress of 64.5 ksi (ksi = kilo-pound force per square inch) is shown for bolting to the Hatch-1 vessel access cover plate at the first power uprate, compared to the design limit of 107.7 ksi, which translates to a 40-% margin. The margin is reduced to only 16-% at the second uprate, owing to higher predicted bolt stresses (90 ksi) associated with increased blowdown loads. This reduction in stress margin is quite dramatic, when compared to the 8-% power increase between these two power uprates. In other cases, the change in margin with a power is less dramatic, which largely stems from the fact that the parameter in question (e.g. stress, temperature, pressure,) remains well below the design limit.

Table E-3. Hatch-1 Reactor Vessel Margins for DBA-LOCA Conditions

Residual Margin = [Design Limit - Value] / Design Limit		
Power Level, MWt	**Predicted Stress, ksi**	**Residual Margin, %**
Vessel Shroud at Support Weld (Design Limit = 15.28 ksi)		
Original = 2436	8.95 ksi	41.4
1st Uprate = 2558	9.05 ksi	40.8
2nd Uprate = 2763	—	—
Vessel Shroud at Head Bolts (Design limit = 69.9 ksi)		
Original = 2436	52.7 ksi	24.6
1st Uprate = 2558	53.0 ksi	24.2
2nd Uprate = 2763	—	—
Vessel Access Hole Cover Plate at Bolts (Design Limit = 107.7 ksi)		
Original = 2436	Original Cover Was Welded	—
1st Uprate = 2558	64.5 ksi	40.1
2nd Uprate = 2763	90.0 ksi	16.4
Jet pump at Diffuser Base (Design limit = 50.7 ksi)		
Original = 2436	31.5 ksi	37.9
1st Uprate = 2558	34.8 ksi	31.4
2nd Uprate = 2763	34.9 ksi	31.2

With regards to plant life extension, margin trends were estimated for several passive components for which time-limited aging analysis (TLAA) was performed for the Hatch license renewal application. TLAA estimates for piping largely center on estimates of the cumulative usage factor (CUF) for cyclic loadings during the period of extended operation. Such

TLAA-CUF estimates essentially involve an assessment of the stress impact of various cyclic operational and off-normal transients which contribute to the total cumulative fatigue to the component considered. The ASME Boiler and Pressure Vessel Code requires that all Class-1 components must have a predicted CUF value less than one at the end of the intended period of operation; thus, the margin for pipe fatigue can be estimated simply as one - CUF. Table E-4 summarizes such margin estimates for the Hatch plant as a function of time. As shown, CUF=0.56 for feedwater piping at 40 years, which increases to 0.72 at 60 years. Similar trends are indicated for primary system components and piping. For some passive components the residual CUF margin at the end of the 60-year extension period is quite minimal. For example, CUF=0.95 for the torus suppression-pool at the end of 60-years, indicating only 5-% residual margin at the end of the license renewal period.

Table E-4. Residual Margin Estimates from Piping Fatigue Usage Analysis for Hatch-1 Renewal (CUF at two significant figures)

Component	Unit	CUF at 40 years	Residual Margin at 40 years, %	CUF at 60 years	Residual Margin at 60 years, %
Residual Heat Removal Suction Piping	2	0.57	43-%	0.77	23-%
Reactor Vessel Equalizer Piping	1	0.52	48-%	0.64	36-%
Core Spray Replacement Piping	1	0.16	84-%	0.19	81-%
Feedwater Piping	2	0.61	39-%	0.83	17-%
Standby Liquid Control Piping	1	0.24	76-%	0.25	75-%
Feedwater (FW), High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), and Reactor Water Cleanup (RWCU) Piping	1	0.56	44-%	0.72	28-%
Steam Condensate Drainage Piping	2	0.66	34-%	0.89	11-%
Main Steam Piping (Line B)	1	0.08	92-%	0.10	90-%
Main Steam Piping (Line D)	2	0.016	>98-%	0.02	98-%

Although such estimates are crude, nevertheless they point to a general trend of component margin reductions for both power uprates and plant life extension. It is important to note that such estimates are for individual components and for separate license actions, i.e. either power increase or life extension. The more difficult problem is to translate changes in component-specific margins to the plant as a whole, i.e. a holistic measure of margin impact for the plant. An even more difficult task is the integration of component-specific margins for the compounding effects of a power increase when combined with plant license renewal, or some other combination of plant changes. Such margin integration efforts were beyond the scope of the work reported here but are recommended for future investigation.

In view of these findings, the following conclusions are made:

- Margin reductions to design limits of specific plant components were noted for the Hatch plant owing to both power increase and license renewal. Since similar changes in component conditions can be expected for other plants involving similar licensing actions, one is drawn to the conclusion of *generic margin reductions* for power uprates and license renewal, although plant-to-plant variations would exist.

- One of the more frustrating aspects of this examination has been the paucity of information provided in licensee Uprate Safety Analysis Reports (SARs) and associated NRC Safety Evaluation Reports (SERs), with regards to the effect(s) of the power uprate on individual component performance and fragility. The case study for the Hatch plant clearly demonstrates the need for considerably more information, if one desires a broad view of margin impact on individual components and the plant as a whole. The development of a Standard Review Plan (SRP) for power uprates (and associated regulatory guidance) would go a long way in remedying this situation. On the other hand, regulatory requirements specified in the Standard Review Plan (SRP) for license renewal, exemplified by aging/fatigue analysis requirements for passive components, provide a transparent means for assessing the margin impact for plant life extension.

- Margin estimates presented in this case study were for individual components and for separate licensing actions. No attempt was made to translate changes in component specific margins to that for the plant as a whole, or to assess the compounding effects of multiple licensing actions. Such margin integration efforts are recommended. In this regard, the agency has initiated a research effort for FY2002-2003, where interacting phenomena and potential synergies for power uprates/license extension are to be examined. The need for such an examination is supported by observations noted in this report.

References:

A. A. W. Cronenberg, *Potential Synergistic Safety Issues Related to Reactor Power Uprates,* Proc. Am. Nucl. Soc., San Diego, Ca (June 2000).

B. M. Khatib-Rahbar, E. G. Cazzoli, and A. Kuritzky, *An assessment of the Risk-Impact of Reactor Power Upgrade for a BWR-6 MARK-III Plant,* Proc. of PAM.-3 Meeting, Crete, Greece, (1997).

C. M. Bonaca, *Potential Synergistic Effects of Industry Initiatives to Extend Plant Life, Increase Production, and Reduce Regulatory Burden*, ACRS Internal Memo, (April, 2000).

1. INTRODUCTION

Recent headline news of electrical power shortages in California and the western states, point to an ever increasing demand for electrical power, which is exacerbated by the fact that little new capacity has been added to the national grid over the past decade. Electricity shortfalls have been compounded by uncertainties/dislocations stemming from deregulation resulting in a very competitive electrical power environment. These developments appear to have affected a more positive public attitude toward nuclear power, as well as market incentives for the continued use of installed nuclear generating capacity. All this has lead to industry initiatives at plant life extension, power uprates, and requests for a longer fuel cycle at ever higher burnups. Indeed industry is aggressively moving toward the goal of maximizing power generation and investment recovery from its aged population of nuclear power plants. Of the approximately 100 nuclear units currently in operation, it is estimated that upwards of 80 may apply for life extensions beyond their current 40-year license. It is also anticipated that most plants will request agency approval for significant increases in power level; recent examples being the 15-% uprate request for the Duane Arnold plant and the 17-% increase for the Dresden and Quad City units. The agency is under considerable pressure to respond to these initiatives and approve such license modifications/extensions in a timely manner. The ACRS is concerned that the safety implications of these compounding actions has not been fully considered. In particular the ACRS is concerned about that the risk impact of combined/synergistic multiple licensing actions, including potential reductions in design basis "margins" (a), which is the subject of this report.

A recent study [1] of operational events noted from License Event Reports (LERs) for power uprated plants, has pointed to potential synergistic(b) safety implications of power uprates when combined with fuel life extensions to higher burnup and plant aging phenomena. Examples cited in that study include control rod insertion problems noted in high-burnup/high-power fuel assemblies for the uprated Wolf Creek plant (uprate/high-burnup synergism), as well as several pipe failure events via corrosion/erosion (aging) effects, notably at the uprated Callaway-PWR and Susquehanna-BWR plants (uprate/aging synergism). In addition to operational evidence for potential safety synergisms, a recent paper by Khatib-Rahbar [2] evaluated the risk impact of a power upgrade for the Swiss Leibstadt-BWR plant. In that study a reduction in safety margin was assessed based on an estimation of the reduced operator response time to a core uncovery event associated with the higher power level. Although the algorithm they used to estimate margin reduction was quite simple, nevertheless it illustrates the point that some decrease in safety can be expected for plants operated at ever higher power levels. They also demonstrate a similar power-dependence on increased containment failure frequency under severe accident conditions (due to containment over-pressurization). They thus conclude that there is a risk impact for plants operated at increased power.

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a) Margin (from Webster): a spare amount or measure allowed fro contingencies, a bare minimum below which something becomes no longer desirable

b) Synergistic (from Webster): the cooperative action of discrete agencies such that the total effect is greater than the sum of the effects taken independently.

Although the agency is moving toward a more risk informed approach to regulation, requirements for risk information to support even singular license actions are minimal. For multiple license actions, say for example a plant life extension with approval for power increase, or for longer fuel cycle and high burnup level with reduced inspection requirements, there is no regulatory requirement for an integrated risk assessment of the compounding effects of such multiple actions. Likewise, there is no explicit NRC requirement to assess potential reductions in "margins" specified in the original FSAR (Final Safety Analysis Report) for multiple actions, or for that matter an individual license change. A brief examination of the License Renewal (LR) Rule further illustrates the point.

1.1 Risk and the License Renewal (LR) Rule

As discussed by Bonaca [3], the License Renewal (LR) Rule rests on the regulatory principle that a nuclear plant can continue to operate for as long as it complies with its current licensing basis (CLB). This approach stems from the regulatory framework that compliance with its CLB provides assurance of adequate protection. Although the license renewal process allows for risk considerations to enter into the review, the use of risk analysis is an option largely left to the applicant. Likewise, there is no explicit regulatory requirement to assess potential reductions in "margins" from those specified in the original FSAR. The regulatory review largely centers on an audit type approach, to insure that individual regulatory requirements for the current licensing basis (CLB) are satisfied over the extended period of operation.

The point is further illustrated by an examination of the License Renewal (LR) rule regarding questions of age degradation of plant structures, systems, and components (SSCs). Active components are specifically excluded from the LR review process, based on the regulatory view that existing regulations already imposes requirements on the timing and level of corrective action required for active components that are subject to periodic failure. For passive components, the License Renewal rule requires that the licensee demonstrate that passive systems will continue to comply with their current licensing basis (CLB), for as long as the plant operates. Passive components fall into two different categories. One class includes structures and components that are subject to periodic replacement under their current licensing basis. These components are identified in the license renewal process for the purpose of reviewing existing CLB commitments dealing with age degradation and to assess their adequacy for the extended period of operation. The other category includes major plant components which would not normally be replaced over the full extended plant life, such as the reactor vessel and internals, emergency systems piping, and the containment. For these components age degradation is to be monitored during the extended operation period, to assure that it will not exceed the CLB age degradation limits.

In most instances long-lived passive components are expected to operate for the extended period of operation, without being replaced, owing to the viewpoint that they were designed with "excess margin" over "regulatory limits" set forth in the original license basis and specified in the as-designed/original plant FSAR (Final Safety Analysis Report). This "excess margin" is also intended to account for uncertainties, contingencies, and off-normal occurrences for the original 40 year plant life. Extending plant life beyond 40 years involves the implicit recognition that "excess margin" is likewise used to compensate for age degradation during the extended period of plant operation. Although "regulatory limits" may not be exceeded for re-licensed plants, it appears that "excess margins" are being reduced. At the end of say 60 years plant life, mechanical components can be expected to be closer to their "fatigue limits" than at the end of the original 40 year lifetime. Likewise, the reactor vessel will be more brittle and closer to the PTS (pressurized thermal shock) limit at 60 years than at 40 years; and so on. Thus, the "excess margin" that was used to support the original license application, is again used in support of plant life extension. The ACRS is concerned that the safety implications of these compounding actions has not been adequately considered in the regulatory process, in particular the combined/synergistic impact of multiple licensing actions on reductions in design basis "margins". These concerns are examined in this report.

1.2 Report Outline

To address concerns regarding potential margin reductions owing to power uprates and plant life extensions, this report is structured as follows. Chapter examines how the concept of "margin" has been incorporated into the regulatory process, specifically in the Code of Federal Regulations (CFR), the General Design Criteria (GDC) for Nuclear Power Plants, Regulatory Guidance (RG), and the Standard Review Plan (SRP). Chapter 2 provides examples of how regulatory margin requirements and guidance are often subsumed into national engineering and design codes, specifically the ASME Boiler and Pressure Vessel Code. Chapter 3 then explores potential margins impacted by a power uprate license action, with specific application to the Edwin Hatch uprate application. Such estimates largely center on a comparison of component operational conditions or predicted loads (stress) with specified design limits for that component. Chapter 4 presents a similar study of margins impacted by plant life extension, which center on estimates of the so-called cumulative usage factor (CUF) for cyclic/fatigue loadings on passive components. These estimates are compared to the allowable CUF limit of one. Chapter 5 provides a discussion of how margin reductions for individual components might be integrated into a more holistic/integrated assessment for the plant as a whole, making use of risk analysis techniques. Report observations, conclusions, and recommendations are summarized in Chapter 6.

1.3 References:

1. A. W. Cronenberg, *Potential Synergistic Safety Issues Related to Reactor Power Uprates,* Proc. Am. Nucl. Soc., San Diego, Ca (June 2000).

2. M. Khatib-Rahbar, E. G. Cazzoli, and A. Kuritzky, *An assessment of the Risk-Impact of Reactor Power Upgrade for a BWR-6 MMARK-III Plant,* Proc. of PSAM-3 Meeting, Crete, Greece, (1997).

3. M. Bonaca, *Potential Synergistic Effects of Industry Initiatives to Extend Plant Life, Increase Production, and Reduce Regulatory Burden,* ACRS Internal Memo, (April, 2000).

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2. USE OF MARGINS IN THE REGULATORY PROCESS

In this chapter a brief overview is provided on concept of margin(s) as used in the regulatory process, as well as in plant operations, to assure overall nuclear power plant safety. Specific examples are also provided for plant component and structural parameters for which "margins" are generally specified for a nuclear power plant (usually in the Final Safety Analysis Report-FSAR for the plant). It will be evident that the concept of margin is broad in its application to nuclear safety.

As a starting point it is instructive to turn to Webster's definition of margin ---*a) spare amount, or measure allowed for contingencies, b) a bare minimum below which something becomes no longer desirable, c) the outside limit or adjoining surface of something , d) the part of a page outside the main body of the text.* Thus, Webster does not provide us with a very explicit or narrow definition of the word, except when applied to a specific application, such as the margin of a page of text. Margin is thus often best defined by example or in combination with a descriptive adjective. It is thus not surprising that margin is a rather loose term used in a multiplicity of ways in the regulatory process, as indicated below.

2.1 Margins in the Regulatory Process

It is instructive to briefly step back in time and review how the concept of "margin" has been incorporated into regulatory process. As will be evident from the discussion presented, "margins" is more of a guiding principal rather than an exacting/specific requirement in both its incorporation into NRC rules & regulations, as well as its application to reactor safety issues of design, construction, and operation. "Margins" in the regulation process can therefore be thought of as analogous to the NRC guiding principals or philosophy of "defense-in-depth" and "adequate protection of the public health and safety".

A good historical perspective on the development of the U.S. regulatory process is provided by Haskin and Camp [1], and is made use of here. In the early days of commercial nuclear power, there were no written criteria against which the various designs could be compared and evaluated to assess a level of safety. As the number of new plant applications grew in the 1960s, there was strong motivation on the part of both industry and the predecessor to the Nuclear Regulatory Commission (NRC), the Atomic Energy Commission (AEC), to streamline the licensing review process. In the mid-19060s the AEC began drafting some general principles or guidelines for the design of commercial nuclear power plants. These guidelines were the forerunner of what was to become know as General Design Criteria (GDC) for Nuclear Power Plants, and which ultimately were incorporated into the Code of Federal Regulations (CFR). In the fall of 1965 the AEC issued a press release announcing the proposed criteria and requesting public comment, which largely revolved around criteria to assure against reactor pressure vessel failure, the China syndrome, and emergency core cooling measures. In July 10, 1967 "interim guidance" were proposed , which provided a framework for nuclear plant design industry for several years. In 1971, the AEC published the initial "General Design Criteria (GDC)" as Appendix A of 10CFR50 [2], thereby giving the weight of federal law to these design criteria.

Table 2-1 provides examples of the use of the word *margin* in the General Design Criteria for nuclear power plants as given in 10CFR50-Appendix A [2]. The GDC provide the foundation for regulatory assessment of the adequacy of plant designs to assure that they can be operated without undue risk to the health and safety of the public. These criteria have been modified over the years, as new information of importance to safety has come to light. The GDC do not provide a quantitative bases for establishing the adequacy of any particular design. The detailed design and its acceptability were deliberately left to the "engineering judgment" of the designer and the regulatory agency.

Table 2-1. Use of Margins in Appendix-A 10CFR50: General Design Criteria for Nuclear Power Plants

Criterion 10-Reactor design. The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that, specified acceptable fuel design limits are not exceed during any condition of normal operation, including the effects of anticipated operational occurrences.

Criterion 31-Fracture prevention of reactor coolant pressure boundary. The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady state and transient stresses. and (4) size of flaws.

Criterion 50-Containment design basis. The reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any loss-of-coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination o! the peak conditions, such as energy in steam generators and as required by 50.44 energy from metal-water and other chemical reactions that may result from degradation but not total failure of emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

Criterion 51-Fracture prevention of containment pressure boundary. The reactor containment boundary shall be designed with sufficient margin to assure that under operating, maintenance, testing, and postulated accident conditions (1) its ferritic materials behave in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the containment boundary material during operation, maintenance, testing, and postulated accident conditions, and the uncertainties in determining (1) material properties. (2) residual, steady state, and transient stresses, and (3) size of flaws.

By the early 1970s the AEC, and subsequently the NRC, began publishing more detailed "regulatory guidance" [see for example, Refs. 3, 4] which provided acceptable design approaches to specific problems. One of the first regulatory guides dealt with the concern that emergency core cooling system should not fail as a result of a loss of containment integrity. It required that sources of emergency core cooling system water be at sufficiently high pressure (provide sufficient net positive suction head, NPSH) to avoid pump cavitation. By 1978 more than 100 different regulatory guides had been issued, and today they number in excess of 200. In addition, numerous regulatory branch technical positions, as well as the Standard Review Plan (SRP, see Ref. 5) for review of an initial license application, provide specific design methodologies and acceptance criteria for assessing the adequacy of a plant design in regards to safety. None of these have the force of law as the GDC; however, the licensee will generally follow approaches outlined in the "regulatory guidance" and "standard review plans" to assure acceptance of a plant design. Thus, the concept of "margin" as provided in the GDC is more explicitly spelled out in "regulatory guidance".

As discussed by Rust and Weaver [6], NRC Regulatory Guides often stipulate that the design of plant systems, structures and components (SSC) should adhere to national standard guidelines. Indeed, both Regulatory Guidance (RG) and the Standard Review Plan (SRP) rely heavily on national "Standards" to provide specific guidelines or rules to follow in the design and construction of nuclear plant systems, structures, and components (SSC). Such standards are essentially a codification of sound engineering principles and experience, which when invoked by the designer can substantially increase the reliability of a component, plant, or facility to perform its function. The national standards program makes a major contribution to reactor safety in licensing, where the availability of a systematic body of well thought-out standards and a codified body of good practice gives the NRC a high level of confidence that the safe performance will be implemented.

The national standards program consists of hundreds of individual tasks in a wide range of areas being carried out by thousands of individual contributors. This activity is coordinated by ANSI (American National Standards Institute) through its Standards Management Board. This group periodically issues reports that indicates the status of various standards that has been issued or is under development. ANSI is largely a coordinating body for codification of standards, while individual professional engineering societies, such as the American Society of Mechanical Engineers (ASME) and the American Institute of Chemical Engineers (AICHE), actually develop particular standards in their respective expertise.

The most widely used standard in the design and licensing of a nuclear power plant is the "ASME Boiler and Pressure Vessel Code" [7], which is was an outgrowth of the 1911 ASME committee for the development of standard rules for the construction of steam boilers. Today the ASME Boiler and Pressure Vessel Code (simply called the "Code") not only provides standards for design, testing, manufacture, and maintenance of boilers and pressure vessels, but has been expanded to include a range of design activities, including standards for in-service inspection and the design and construction standards for concrete structures (Division 2, Section III of the code). The primary objective in establishing all such standards or codes (often used synonymously), is the "protection of life and property and to provide a margin for deterioration in service as to give a reasonably long, safe period of usefulness" [7]. Thus the concept of "margin" is again incorporated into national standards (codes). Rules and guidance incorporated into these

Codes change form time to time, as experience in their use accumulates and as advances in materials and design techniques improve.

The following section provides a brief overview of the regulatory process for incorporation of safety margins into reactor plant designs, which is summarized in Table 2-2. Application of this process follows in Section 2.3, where example margins (quantitative values) are provided for the Hatch nuclear power plant based on parameter values from the FSAR and Technical Specifications for that plant.

Table 2-2: Illustration of Regulatory Process for Incorporation of Safety Margins into Reactor Plant Designs

- **Code of Federal Regulations (CFR)**
  Appendix-A: General Design Criteria (GDC)

- **Standard Review Plan (SRP) and Regulatory Guides (RG)**

- **National Standards and Codes**
  ASME Boiler and Pressure Vessel Code

- **Example: Hatch Nuclear Power Plant**
  Hatch Final Safety Analysis Report (FSAR), 1978
  NUREG-0411: "Safety Evaluation Report (SER) for Hatch.......", 1978
  NUREG-0395: "Technical Specifications (TS) for Hatch...........", 1979
  NUREG-0417: "Final Environmental Impact (EI) ....for Hatch", 1978

2.2 Regulatory Requirements for *Adequate Margin*

As mentioned the General Design Criteria (GDC) specified in 10CFR50/App.-A provide the weight of federal law to assure the safety o nuclear power plants. For illustrative purposes, let us use examine General Design (GD) requirement number-31 to see how it translates into a specific or quantitative margin, i. e:

> *Criterion 31-Fracture prevention of reactor coolant pressure boundary*: The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized.

Since this criteria is quite broad, the plant designer looks to NRC regulatory guides and the Standard Review Plan (SRP, see Ref. 5) to provide more explicit guidance to satisfy the requirement for "sufficient margin" for the reactor pressure boundary. Chapter-5 of the SRP deals with the "Reactor Coolant System and Connected Systems" and provides review procedures and acceptance criteria for the reactor pressure boundary (e.g. pressure vessel, primary system piping, pressurizer for PWRs, etc). Table 2-3 presents a listing of topics covered

Chapter-5. Here we examine several subsections of that chapter to better ascertain how the designer satisfies "sufficient margin" requirements for the reactor pressure boundary. Specifically we examine subsections:

5.2.1.1 Compliance with Codes and Standard (Rule 10CFR50.55a)
5.3.1 Reactor Vessel Materials
5.3.2 Pressure-Temperature Limits

Table 2-3. Listing of Subsections in SRP Chapter-5: Reactor Coolant System And Connected Systems

5.2.1.1	Compliance with the Codes and Standard (Rule: 10CFR50.55a)
5.2.1.2	Applicable Code Cases
5.2.2	Over-pressure Protection (BTP-RSB 5-2)
5.2.3	Reactor Coolant Pressure Boundary Materials (BTP-MTEB 5-7)
5.2.4	Reactor Coolant Pressure Boundary In-service Inspection and Testing
5.2.5	Reactor Coolant Pressure Boundary Leakage Detection
5.3.1	Reactor Vessel Materials
5.3.2	Pressure-Temperature Limits (BTP-MTEB 5-2)
5.3.3	Reactor Vessel Integrity
5.4	Preface
5.4.1.1	Pump Flywheel Integrity (PWR)
5.4.2.1	Steam Generator Materials (BTP MTEB 5-3)
5.4.2.2	Steam Generator Tube In-service Inspection
5..4.6	Reactor Core Isolation Cooling System (BWR)
5.4.7	Residual Heat Removal (RHR) System (BTP RSB 5-1)
5.4.8	Reactor Water Cleanup System (BWR)
5.4.11	Pressurizer Relief Tank
5.4.12	Reactor Coolant System High Point Vents

Subsection 5.2.1.1: Compliance with Codes and Standard (Rule 10CFR50.55a), states that pressure-retaining components must designed in compliance with the 10CFR50.55a (the Codes and Standards Rule). The intent of this Rule was to directly incorporate reference to the ASME-Boiler and Pressure Vessel Code (or simply the ASME-Boiler Code) into the Code of Federal Regulations, thus giving the ASME-Boiler Code the full force of federal law as it pertains to nuclear plant design and construction. Additionally Section 5.2.1.1 states that all components of the reactor coolant pressure boundary be designated as Class I components (where Section III Division-I of the ASME Boiler Code applies for nuclear power plants). Section 5.2.1.1 also states that the applicant is required to provide a summary table in his Safety Analysis Report (SAR), identifying the applicable codes which were used in the design of the pressure vessel, primary piping, pumps and valves. This table must provide such information as the applicable code or standard, code edition, applicable addenda, and the component order date for each pressure boundary component. The primary effect of this section is to enforce that all pressure boundary components comply with the ASME Boiler Code, which is likewise reiterated in the additional subsections cited below.

Subsection 5.3.1: Reactor Vessel Materials, gives general guidelines for material specifications used for the reactor vessel and applicable appurtenances (shroud support, studs, control rod drive housings, instrumentation housings, etc). It states that the materials are reviewed by NRC to assure the adequacy of mechanical and physical properties, the effects of irradiation on these materials, their corrosion resistance, and how materials were fabricated. Acceptance criteria used by NRC are that the materials used are again in compliance with the ASME Boiler Code-Section III. Requirements for adherence to specific sections of the Code are stated, in particular requirements of Section III/Appendix I, and Section II/Parts A, B, and C. The materials must also meet the specifications outlined in 10CFR50-Appendix G, which again indicate reliance on the ASME-Boiler Code. Section 5.3.1 also states that the acceptability of materials not specified in the ASME Boiler Vessel Code will be considered on an individual basis. Additionally adherence to acceptable fabrication processes are also stated, including the requirement that the reactor vessel be fabricated in accordance with the ASME Boiler Code Section III, paragraphs NB-2000, 4000, and 4100.

Methods for nondestructive examination of materials are also specified and should be in compliance with Section III, NB-5000 of the ASME Boiler Code. Other welding and testing requirements are also given for steel and stainless steel components. Again, the ASME Boiler Code largely dictates materials specification requirements for the reactor vessel.

Section 5.3.2: Pressure-Temperature Limits, are imposed on the reactor coolant pressure boundary, to assure the structural integrity for the ferritic components of the reactor coolant pressure boundary. This requirement is met by the assurance that material of the reactor coolant pressure boundary (vessel, piping, etc) possess adequate fracture toughness to resist rapidly propagating failure of a structural flaw and that the pressure boundary materials act in a non-brittle manner when stressed under operating, maintenance, testing, and anticipated operational conditions. The fracture toughness requirements for ferritic materials are specified in Appendix G of 10CFR50, which in turn relies on the ASME Boiler Code (Appendix-G/Section-III). Pressure-temperature calculation procedures are described in Appendix G of the ASME Code; while the detailed technical basis for the ASME code requirement is provided by the Welding Research Council (WRC) Bulletin 175, 11PVRC Recommendation on Toughness Requirements for Ferritic Materials." Changes in the fracture toughness properties of materials in the belt-line region of the reactor pressure vessel, resulting from neutron irradiation and the thermal environment, are monitored by a surveillance program in compliance to the requirements of 10CFR50/Appendix-H. The effect of neutron fluence on the shift in the nil-ductility temperature of the reactor vessel is provided by predictive methods outlined in Regulatory Guide 1.99, "Effect of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials." Very detailed guidance and example calculations are provided to the designer for incorporation into the plant FSAR (Final Safety Analysis Report) to assure that adequate pressure-temperature limits to avoid flaw propagation that could lead to vessel failure. These vessel pressure-temperature limits are also incorporated into the plant Technical Specifications.

The above discussion provides a brief overview of how margin, as a concept, has been incorporated into regulatory process. As is evident, "margin" is more a guiding principal rather than an exacting requirement in both its incorporation into NRC rules & regulations, as well as its application to reactor safety issues of design, construction, and operation. In many respects it is analogous to the NRC guiding principals or philosophy of "defense-in-depth" and "adequate protection of the public health and safety". The purpose of the present study however, is to examine the safety implications of multiple licensing actions and potential combined/synergistic effects on potential margin reductions. This requires a more narrow examination of how one ascribes a specific or quantitative margin to a particular reactor parameter or design feature, and how a particular licensing action or multiple of licensing actions impact that particular parameter-specific margin, which is best accomplished by example.

In the following chapter several margins (quantitative values) are examined for the Hatch nuclear power plant, based on design parameter values taken from the FSAR and Technical Specifications for that plant. An attempt is then made to compare the same quantitative value for a parameter-specific margin at the different power uprate conditions that have been made for that plant. In this manner we are able to assess potential margin reductions for the same plant parameter stemming from multiple licensing actions, in this case several power uprates.

2.3 References

1. F. E. Haskin and A. L. Camp, *Perspectives on Reactor Safety*, NUREG/CR-6042, (March 1994).
2. Office of the Federal Register, *Code of Federal Regulations: Parts 1 to 50 (Energy)*, U .S. Government Printing Office, (January 1,2000).
3. U. S. Nuclear Regulatory Commission, *Draft Regulatory Guide DG-1008: Reactor Coolant Pump Seals*, (April 1991).
4. U. S. Nuclear Regulatory Commission, *Regulatory Guide 1.160: Monitoring the Effectiveness of Maintenance at Nuclear power Plants*, (March 1997).
5. U. S. Nuclear Regulatory Commission, *Standard Review Plan: for the Review of Safety Analysis Reports for Nuclear Power Plants*, NUREG-0800, (June 1987).
6. J. H. Rust and L. E. Weaver, *Nuclear Power Safety*, Pergamon Press, Inc, New York (1977).
7. *ASME Boiler and Pressure Vessel Code*, The American Society of Mechanical Engineers, New York, NY, 1988 Edition (July 1, 1988).
8. U.S. Nuclear Regulatory Commission, *Technical Specifications for Edwin Hatch Nuclear Plant*, NUREG-0395, (June 1978).
9. U.S. Nuclear Regulatory Commission, *Safety Evaluation Report Related to the Operation of the Edwin Hatch Nuclear Plant*, NUREG-0411, (June 1978).
10. U.S. Nuclear Regulatory Commission, *Final Environmental Statement for Edwin Hatch Unit-2*, NUREG-0417, (March 1978).

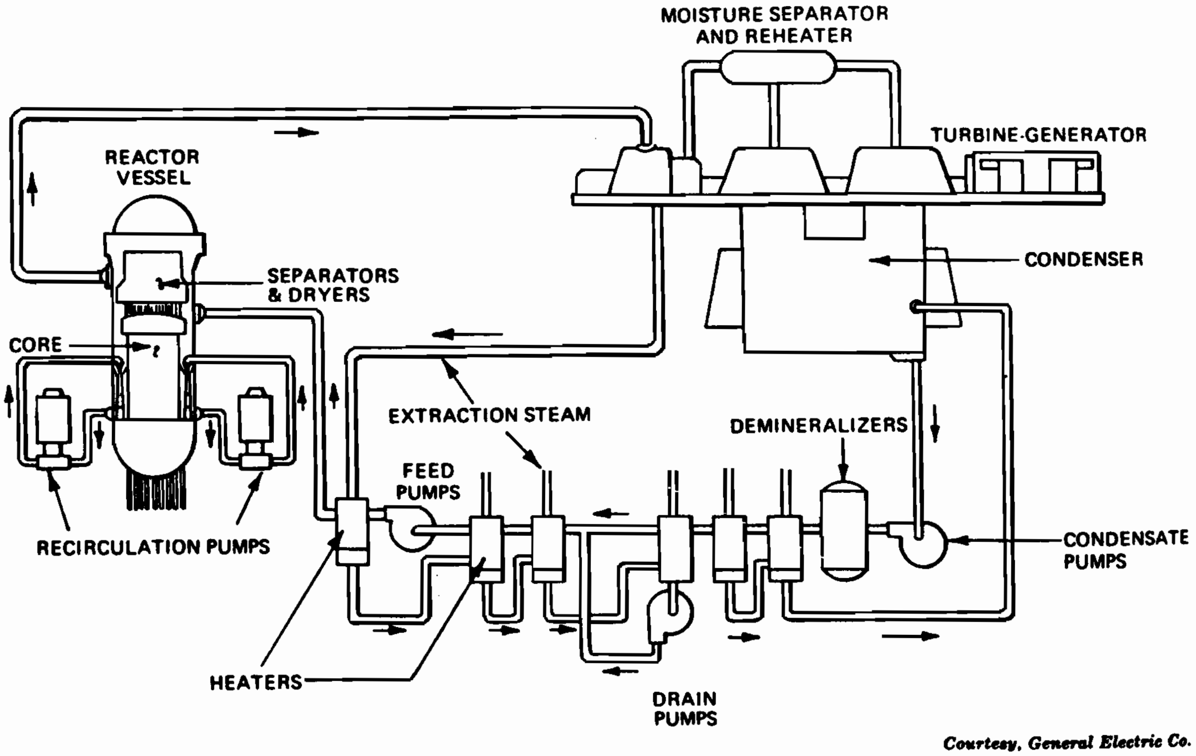
3. POTENTIAL MARGIN REDUCTIONS FOR POWER UPRATES

In this chapter we examine changes in plant operating conditions, technical specifications, and other plant parameters that may be altered as a result of a power uprate, and attempt to estimate from these changes in plant conditions/parameters reductions in "parameter-specific margins"; that is we attempt a "quantitative estimate of margin change" for a particular plant parameter due to the power increase. We use as an example the several power uprates for the Hatch Units 1 & 2 BWR plants. Such a "quantitative estimate of margin change" might involve, for example, a component or system temperature at the uprated condition compared to that at the initial power level, so that the margin impact might be estimated of change in temperature compared to the design temperature limit for that particular component or system. Another example might involve a comparison of the predicted stress to a specific component under Design Basis LOCA conditions at the initial and uprate power levels, compared to the ASME Boiler Code stress design limits for that particular component. As will be evident, the difficulty in such an assessment largely relates to the task of obtaining a consistent set of parameter values at the various power levels and associated design limits, nevertheless some success was achieved. It should be noted that the study is not intended to be a full-scope investigation of margin changes for the Hatch plant, but rather simply an illustration of how margin trends might be assessed from a limited investigation of some key plant parameters impacted by a power uprate.

3.1 Hatch Plant Operating Conditions/Parameters Impacted by Power Uprates

The Hatch Units 1 and 2 are sister GE-BWR/4 plants of similar design and having much the same operating conditions. Figure 3-1 illustrates basic characteristics of the reactor coolant system for direct-cycle GE-BWR/4 type plants. Figure 3-2 presents a schematic of the Hatch Mark-I type containment, with its inverted light-bulb and torus/pressure-suppression pool features.

Unit-1 received its operating license in 1974 at an initial licensed thermal power limit of 2436MWt . Unit-2 received its operating license in 1978, also at 2436MWt. Both plant requested and received power uprate approvals in 1995 [1], each to a new limit of 2558MWt, representing a 5-% increase. This was followed by a second uprate request in 1997 [2] to 2763MWt for both units, representing an 8-% power increase from prior power level and an effective 13.4-% increase from the initial licensed power. In their second uprate proposal, the licensee stated that the power increase was based upon limitations and modification costs related to the balance-of-plant (BOP) equipment, and not upon design limitations within the nuclear steam supply system (NESS). Although the first uprate of a 5-% involved a 35 psi increase in reactor operating pressure, the second 8-% power uprate did not involve an increase in reactor pressure, rather it was accomplished by higher primary steam flow to the turbine generator and higher feedwater flow. Table 3-1 summarizes plant operating parameters for Units 1 and 2 at initial and uprated power conditions, where parameter values are based on conditions provided in Refs. 3 through 6.



Courtesy, General Electric Co.

Figure 3-1. Illustration of the essential features of the reactor coolant system for direct-cycle GE-BWR/4 type plants.

Table 3-1. Summary of Hatch Units 1 & 2 Operational Conditions

Parameter	Hatch Unit-1 (BWR/Mark-I)			Hatch Unit-2 (BWR/Mark-I)		
Thermal Power, MWt (Year-Start)	2436 (1975)	2558 (1995)	2763 (1997)	2436 (1979)	2558 (1995)	2763 (1997)
% Power Uprate (from prior value)	--	5-%	8-%	--	5-%	8-%
Core Coolant Flow Rate, 10^6 lb_m/hr (@ %-Power)	68.3-82.4 (87-105)	68.3-82.4 (87-105)	68.3-82.4 (87-105	67-80.9 (87-105)	67-80.9 (87-105)	67-80.9 (87-105
Vessel Steam Flow, 10^6 lb_m/hr	10.0	10.6	11.5	10.5	11.1	12.0
Steam Dome Pressure, psig	1015	1050	1050	1015	1050	1050
Steam Dome Temp., °F	547	551	551	547	551	551
Full-Power Feedwater Flow, 10^6 lb_m/hr	10.1	10.7	11.6	10.5	11.2	12.1
Full-Power Feedwater Temp., °F	388	393	398	420	424	425

See Following Sources
Ref. 3: Table 4-1 Ref. 4: Table 1-2
Ref. 5: Table 1-2 Ref. 6: Table 1-2

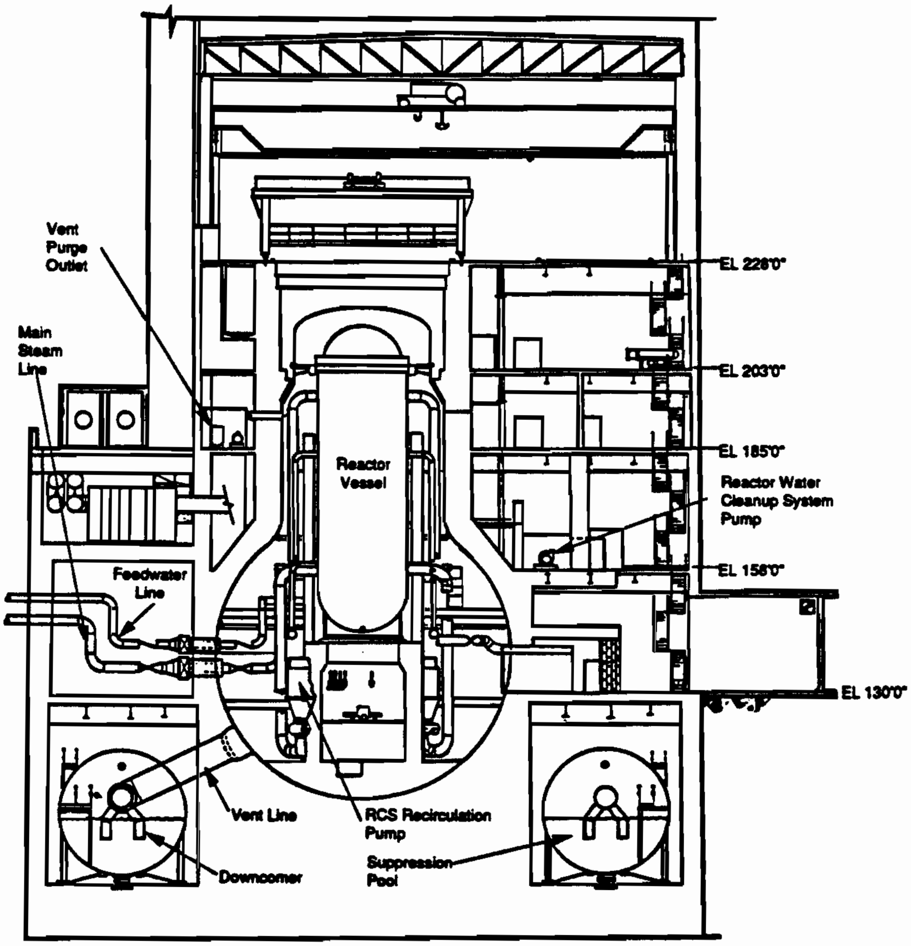


Figure 3-2. Schematic of the Hatch Mark-I type containment, with its inverted light-bulb and torus/pressure-suppression pool features.

Included in the Hatch power uprate applications for both units was a "No Significant Hazards Evaluation" under NRC criteria 10CFR50.92, where the applicant is required to demonstrate that is the proposed amendment would (underline here):

> "not (a) Involve a significant increase in the probability or consequences of an accident previously evaluated; or (b) Create the possibility of a new or different kind of accident from any accident previously evaluated; or (c) Involve a significant reduction in a margin of safety" .

With regards to the nil reduction in margin requirement, the following statement is abstracted from the 1997 Hatch Power Uprate Licensing Submittal (Ref. 2, see 10CFR50.92 evaluation, conclusion statement of Enclosure-2):

> "The spectrum of postulated accidents and transients was investigated and was determined to meet the current regulatory criteria for Plant Hatch at extended power uprate conditions. In the area of core design, fuel operating limits will still be met at the new power level, and fuel reload analyses will show plant transients meet the NRC-accepted criteria as specified in the plant Technical Specifications. Challenges to fuel and ECCS performance were evaluated and shown to meet the criteria of 10 CFR50.46 and 10CFR50/App.-K. Challenges to the containment were evaluated and the integrity of the fission product barrier was confirmed. Radiological release events were evaluated and shown to meet the guidelines of 10CFR100. The proposed Operating License and Technical Specifications changes are consistent with the Plant Hatch extended power uprate evaluations. The evaluations demonstrate compliance with the margin-assuring acceptance criteria contained in applicable codes and regulations. Therefore, the proposed Operating License and Technical Specifications changes do not involve a significant reduction in the margin of safety."

Attached to the uprate application, was a Safety Analysis Report (SAR) prepared by GE Nuclear Energy (see Ref. 6), where the following statement on margins is abstracted from that report (see pg 1-3, underlined here):

> "The extended power uprate analysis basis described above assures that the power-dependent safety margin prescribed by the Code of Federal Regulations (CFR) will be maintained by meeting the appropriate regulatory criteria. NRC-accepted computer codes and calculational techniques are used to make the calculations that demonstrate meeting the stipulated criteria. Similarly, factors of safety specified by application of the code design rules will be maintained, as will other margin assuring acceptance criteria used to judge the acceptability of the plant."

These are but two of the many statements provided in the documentation supporting the uprate application, which refer to maintenance of adequate safety margin. To present something other than broad statements on maintenance of adequate margin, a more narrow approach is taken here, where we examine specific changes to plant parameters and conditions (based on information provided by the applicant) resulting from the two power uprates noted above (5-%, 8-%). Here we concentrate on licensee evaluated changes in parameters/conditions for the reactor coolant and connected systems, as well as for the engineered safety features (including containment). Most of the information is based on discussions and parameters evaluated in the uprate Safety Analysis Reports [5,6] provided by GE Nuclear Energy in support of the 1995 and 1997 uprates applications [1,2]. Here parameter values/conditions are assumed to be similar for both Units 1 and 2, unless otherwise noted.

Table 3-2 presents information (see Ref. 6, GE-SAR for second uprate) on estimated changes to operational pressure and temperature conditions for various piping categories for the Hatch-1 plant, where conditions are compared for the original power and at the second uprate (similar Table was not found in first uprate submittal). The effects of the uprate on piping conditions are shown for the main steam line, feedwater, re-circulation loop (suction and discharge), and high pressure emergency core coolant system (ECCS) piping. These systems were selected because they are part of the primary reactor coolant pressure boundary (RCPB) and could be affected by an uprate-related increases in primary coolant and steam flows, pressure, or operating temperatures. It is noted that the values given in Table 3-2 are for the piping evaluations at the original licensed power of 2436 MWt, while the values cited for the second uprate are at 102-% (2818 MWt) of the requested power increase to 2763 MWt. These systems were evaluated for compliance with design values. As indicated, changes in primary system conditions owing to the power uprate do not indicate that piping design limits are exceeded. Thus the licensee concluded *sufficient margin* was maintained at the uprated power with the as-built piping. The uprate-SAR [6] also notes that piping thickness values of carbon steel components could be affected by flow-assisted corrosion (FAC), thus the Hatch plant licensee established a program for monitoring pipe wall thinning of all primary carbon-steel piping.

Table 3-2. Pressure Boundary Operational Conditions for Hatch-1 at Original and Second Uprate Power, and Comparison with Design Limits (see Ref. 6)

	Piping Categories										
	Main Steam			Feedwater		Recirc-Suction		Recirc-Discharge		ECCS	
Condition	Flow (lb_m/hr)	Press (psig)	Temp (°F)	Press (psig)	Temp (°F)	Press (psig)	Temp (°F)	Press (psig)	Temp (°F)	Press (psig)	Temp (°F)
Design limit	--	1250	575	1650	562	1250	575	1325	562	1250	575
Original Power at 2436 MWt	10.03	1015	546	1130	392	1053	534	1222.7	535	1053	534
Second Power Uprate at 2763 MWt (evaluated at 102-% of power, i.e. 2818 MWt)	11.81	1050	551	1088.3	400	1042.6	532.2	1214.3	533.1	1042.6	532.2
Percent Increase	17.7-%	3.8-%	0.9-%	0.0-%	1.9-%	0.0-%	0.0-%	0.0-%	0.0-%	0.0-%	0.0-%

Note: Values are taken directly from GE-SAR for second uprate; values may not be exactly as indicated in Table 3-1.

3.2 Hatch Plant DBA Conditions/Parameters Impacted by Power Uprates

As mentioned, requirements of 10CFR50.92 include a *No Significant Hazards Evaluation* for power uprate license amendments, including a demonstration that adequate safety margins shall be maintained. A license amendment request for a significant power increase thus generally includes a re-analysis of design basis accidents (DBA) and associated stress loads on key pressure boundary piping and components. Such DBA re-analysis was included in both Hatch power uprate requests.

Refs. 5 and 6 provide a re-assessment of DBA conditions and associated stress loads for the two Hatch plant uprates. The stress calculations were based on internal loading combinations that included component stresses associated with reactor internal pressure difference (RIPD), in combination with LOCA associated stresses due to either a main steam line break or a re-circulation line break. Since there is no increase in seismic or fuel lift loads with a power uprate, only the effects increased RIPD and LOCA loads were evaluated. Both flow-induced and acoustic loads were determined. The flow-induced loads consist of the short duration flow-induced and acoustic impulse loads resulting from a postulated break of the re-circulation suction line. Acoustic shock loads are loads impacting components near the re-circulation outlet nozzle resulting from the decompression shock wave which originates from a re-circulation line break.

It should be noted that although a re-examination of DBA loads under 10CFR50.92 requirements was provided in Refs. 5 and 6 (GE-Uprate Safety Evaluation Reports), these references present only summaries of predicted results. In many cases the predicted DBA stresses summarized for the two power uprates were for different components, or if for the same component not at the same location. It should also be noted that although in most cases predicted loads increase with an increase in power, this is not always true. Re-calculated loads at the higher power can decrease relative to the original FSAR values owing to improvements in the analysis methods employed or the thermal-hydraulic characteristics of newer fuel assembly designs that may accompany the uprate. For these reasons it was difficult to make a one-to-one comparison, although some success at consistency was achieved.

Table 3-3 compares the maximum predicted LOCA stresses of various components (at their maximum stress locations, as indicated) at the original licensed and first uprate power levels. Also given is the allowable stress based on the ASME Boiler and Pressure Vessel Code. Similar information is presented in Table 3-4, comparing LOCA predicted stresses the first and second uprate conditions. As noted, a comparison on these two tables indicates that the predicted stresses summarized in Refs. 5 and 6 were not always for the same component, or if for the same component not the same location. An exception is for the jet-pump, where the LOCA stresses were reported for all three power levels at the same jet-pump diffuser base location.

Predicted results summarized in both Table 3-3 and 3-4 indicate the general trend of increased stress with an increase in power. Indeed, in all cases some increase in stress from the prior power condition is evident, the one exception being a similar stress for the Unit-2 shroud support plate at the original and first uprate condition (see Table 3-3). Likewise, only a minor increase in stress is indicated for the jet pump diffuser due to the power rise from the first and second uprates. For all other components, some increase in stress with power is indicated.
For example as shown in Table 3-4, the estimated stress on the shroud tie-rod for off-normal LOCA conditions is shown to be about 24 ksi at the power level of 2558 MWt (1st uprate), which increases to 26.5 ksi at 2763 MWt (second uprate).

A more dramatic increase in stress with power level is noted for the access cover tie-down bolts, that is 64.5 ksi at the 2558 MWt (1995), which increases to 90 ksi at 2763 MWt (1997). Although both values are shown to be below the ASME allowable limits, the estimated increase in predicted bolt stress is almost 40-% (i.e. [90 - 64.5]/64.5=39.5) for the 8-% delta rise in power; nevertheless, the predicted conditions are shown to remain below allowable ASME design values. Two point however are noteworthy in regards to these bolt stresses. First, reference sources do not indicate whether the predicted stresses are for the same bolt (unspecified number of hold-down bolts per plate) or for the same cover plate (2 cover plates per reactor), or that the same LOCA stress model was used in both predictions. Secondly, it is noted that the predicted bolting stresses are given only for the 1995 and 1997 uprates, and not at the original 1975 power level. As discussed in Appendix-A, this is due to cover plate replacements in 1993 (Unit-1 cover replacement) and 1994 (Unit-2 cover replacement), stemming from findings of possible Inconel welding flaws in the original cover plates. Thus, the early welded cover plates were replaced with new bolt-design cover plates for both units prior to power uprating.

The one component for which stresses at the same location were estimated and compared in Refs. 5 and 6 for both power uprates, as well as at the original design power, is for the jet pump at the diffuser base. The predicted stresses at this location are shown to exhibit a modest increase with power, that is 31.5 ksi (31,500 psi) at the original operating power of 2436 MWt, rising to 34.8 ksi at 2558 MWt (first 5-% uprate), and then to 34.9 ksi at 2763 MWt (second 8-% uprate). These stress values again remain below the allowable ASME design stress of 38 ksi.

Table 3-3. Summary Comparison of DBA-LOCA Predicted Stresses at the Original and First Uprate Power Levels (see Ref. 5)

Reactor Component	Location of Maximum Stress	Predicted Stress (ksi) at 2436 MWt	Predicted Stress (ksi) a t 2558 MWt	Design Stress (ksi), ASME Code
Unit-1 Vessel Shroud	Shroud-Spring Contact	46.2	46.2	50.7
Unit- 2 Vessel Shroud	Shroud-Support Weld	8.95	9.05	15.28
Units 1&2 Shroud Head	Bolts	52.7	53.0	69.9
Units, 1&2 Jet Pump Diffuser	Diffusor Base	31.5	34.8	50.7
Unit- 2 Shroud Support	Support Plate	66.5	66.5	76.1
ksi = kilo-pound force per square inch				

Table 3-4. Summary Comparison of DBA-LOCA Predicted Stresses at the First and Second Uprate Power Levels (see Ref. 6)

Reactor Component	Location of Maximum Stress	Predicted Stress (ksi) at 25558 MWt	Predicted Stress (ksi) at 2763 MWt	Design Stress (ksi), ASME Code
Unit-1 Vessel Shroud (Repair)	Tie Rod	24.0	26.5	32.2
Unit-1 Vessel Shroud	Mid-Support	20.0	24.3	38
Units, 1&2 Jet Pump Diffuser	Diffuser Base	34.8	34.9	38
Unit-1 Access Hole Cover Plate	Bolts	64.5	90.0	107.7
ksi = kilo-pound force per square inch				

25

The impact of increased power on containment performance was also evaluated as part of the GE-Uprate Safety Analysis Report (Refs. 5 and 6). As discussed in Refs. [5] and [6], operation at higher power levels changes some of the conditions for the containment analyses. For example the LOCA blow-down rate, and thus pressurization of the containment shell, is largely governed by the reactor fluid inventory and its energy, which increase somewhat with higher power levels. Likewise, the long-term heatup of the suppression pool following a DBA-LOCA is governed by the ability of the residual heat removal (RHR) system to accommodate decay heat, which again depends on the power level. Therefore, the Hatch containment pressure and temperature response for both units were re-analyzed at the uprated conditions, where results are summarized in Table 3-5 for the original and two uprated power conditions. It should be noted that containment performance results provided in Refs. 5 and 6 are based on predictions at 102-% of operational power.

Table 3-5. Summary of Power Uprate Containment Performance Predictions

Parameter	Original Power at 2436 MWt	1st Uprate at 2558 MWt (prediction at 102-% power or 2609 MWt)	2nd Uprate at 2763 MWt (prediction at 102-% power or 2828 MWt)	Design Limit
Unit-1				
Peak Dry-well Pressure, psig	47.9	49.6	50.5	56 (Max.=62)
Peak Dry-well Gas Temp., °F	290 (exceeds design limit for short time)	292 (exceeds design limit for short time)	293 (exceeds design limit for short time)	281
Peak Suppression Pool Temp., °F	198 (uprated analysis), 204 (FSAR)	202 (uprated analysis)	208 (uprated analysis)	281
Unit-2				
Peak Dry-well Pressure, psig	43	45.5	46.9	56 (Max.=62)
Peak Dry-well Gas Temp., °F	289	292	292	340
Peak Suppression Pool Temp., °F	198 (uprated analysis), 209 (FSAR)	202 (uprated analysis)	208 (uprated analysis)	340

As would be expected, containment pressures and temperatures are shown to increase somewhat with increased power, owing to higher fluid inventory and energy conditions at the higher power levels. For example Table 3-5 shows that the bulk suppression pool temperatures will increase slightly with increased power; however predicted uprate temperatures are well below the design limits (281°F for Unit-1 and 340°F for Unit-2). Table 3-5 also includes comparisons of the peak dry-well pressure. As shown the maximum dry-well pressure at uprate conditions are bounded by the design pressure; nevertheless for uprated conditions some decrease in pressure and temperature margins is evident. The calculated peak dry-well gas temperature for Unit-2 remains less than its design value of 340°F. For Unit-1 this peak temperature is shown to exceed the shell design value somewhat, i.e. by 9°F at the original power and 11°F for the second uprate. However, these "peak" temperatures apply only at the beginning of the accident (for about 20 sec); thus the dry-well temperature increase was not considered a threat to the shell structure.

3.3 Margin Reductions for Plant Conditions Impacted by Power Uprates

As indicated from the above discussion, the primary purpose of the uprate safety analysis report (SAR), which accompanies an uprate Licensee Amendment Request (LAR), is to demonstrate that the plant can be operated safely and that all regulatory requirements would be met at the elevated power level. Statements to the effect that "adequate margin is maintained" can be found throughout the SAR, largely based on a comparison of a plant condition or parameter with the design limit(s) or ASME Code specifications for the particular system or component in question. The NRC review of the amendment request, documented in the Safety Evaluation Report (SER, see Ref. 3), likewise points to "adequate margin" if operational conditions or off-normal predicted conditions remain below design or regulatory limits. Generally neither the Licensee-SAR or NRC-SER present or discuss comparative type indicators of "margin changes"; which largely stems from the regulatory perspective that so long as design or regulatory limits are not violated adequate protection is maintained and amendment approval is justified. Here we attempt to put a more "quantitative" perspective on changes in margin due to a power increase.

Since "margin" is a rather general term, any "quantitative" evaluation of its value is largely based on user definition. Here we make use of several definitions. In its most general sense, margin can simply be expressed as the difference between the actual parameter value versus some limit criteria, usually the design limit, thus:

$$\boxed{\text{Margin} = \text{Design Limit} - \text{Actual}}$$

Probably more useful for present purposes is some measure of residual for a particular operating parameter or component load relative to the design limit for that parameter. For this purpose we define "residual margin" as:

$$\boxed{\text{Residual Margin} = \frac{\text{Design Limit} - \text{Actual Value}}{\text{Design Limit}}}$$

Tables 3-6 , 3-7, and 3-8 summarize residual margin estimates for Hatch Unit-1 plant at the initial licensed power, as well as at the first and second power uprates.

Table 3-6 presents residual margin estimates associated with changes in Unit-1 plant operational conditions. As indicated, the increase in main steam-line pressure from the startup condition of about 1015 psig to 1050 psig for the first and second uprates results in a decrease in residual margin from about 18.8-% at the initial power to approximately 16-% at the second uprate. A reduction in temperature margin for the main steam-line is also evident, owing to the higher operational steam temperatures associated with increased power. Of particular note is the rather small residual temperature margin for the main steam-line, owing to the fact that at second uprated power level the operational steam temperature of 551 of approaches the steam-line piping design limit of 575 of. These margins compare to an overall effective power uprate of 13.4-% (1997-Uprate at 2763 MWt, compared to the initial power of 2463 MWt). Although such comparisons are limited, the salient point to note is that margin reductions indeed arise. The impact of a power uprate on margins can be even greater for off-normal conditions, as is evident from a comparison of reactor vessel and containment performance parameters for DBA-LOCA conditions.

Table 3-6. Summary of Hatch-1 Operational Margins

Power Level, MWt	**Parameter Value**	**Residual Margin, %**
Main Steam-line Pressure (Design Limit = 1250 psig)		
Original = 2436	1015 psig	18.8
1st Uprate = 2558	1050 psig	16
2nd Uprate = 2763	1050 psig	16
Main Steam-line Temperature(Design Limit = 575 °F)		
Original = 2436	546 °F	5.04
1st Uprate = 2558	---	---
2nd Uprate = 2763	551 °F	4.17
Feedwater Pressure (Design Limit = 1650 psig)		
Original = 2436	1130 psig	31.5
1st Uprate = 2558	---	---
2nd Uprate = 2763	1088 psig	34.1
Feedwater Temperature (Design Limit = 562 °F)		
Original = 2436	392 °F	30.2
1st Uprate = 2558	---	---
2nd Uprate = 2763	400 °F	28.8

Tables 3-7 and 3-8 provides margin estimates based on predicted stresses for the reactor vessel (and its components) and the containment for design basis accident (DBA)-LOCA conditions. As noted previously, although a re-examination of DBA-LOCA stress loads is stipulated for power uprates under 10CFR50.92 requirements, often the component stress predictions summarized in the licensee's Uprate Safety Analysis Report (SAR) are for different components then analyzed in the original FSAR, or if for the same component not at the same location. Likewise, load predictions at elevated power may decrease relative to original FSAR, owing to improvements in the analysis methods employed or to the thermal-hydraulic characteristics of newer fuel assembly designs that may accompany the power uprate. For these reasons it is often difficult to make a one-to-one comparison, although some success is evident from inspection of results presented in Tables 3-8 and 3-9.

Table 3-7 reveals a general decrease in residual margin with increased power for various vessel locations and components, owing to a general increase in LOCA blow-down forces associated with the increased coolant enthalpy that accompanies a power uprate. The most dramatic decrease in margin revealed in Table 3-7 is that associated with loads on the bolting of the vessel access cover plate. Results indicate a residual margin of 40.1-% at the 1st power uprate, which is reduced to only 16.4-% residual margin at the 2nd uprate; which largely stems from the fact that blowdown stress at the 2nd uprate increases by almost 1/3 (64.5 ksi to 90 ksi) and approaches the design limit of 107.7 ksi. This reduction in stress margin is quite dramatic when compared to the 8-% power increase between the 1st and 2nd uprates. In the safety analysis report (SAR) for the second uprate, it was nevertheless argued that since the predicted LOCA blowdown stresses still remain below design limits, "adequate margin is maintained".

Table 3-8 provides similar type margin estimates for the containment for DBA-LOCA conditions. Again, a general decrease in residual margin is evident with increased power level, owing to the increased coolant enthalpy that accompanies a power uprate. As would be expected, both dry-well and wet-well temperature and pressure conditions increase with increased power; thus the residual margin also is reduced at the elevated power as design limits are approached. It is also noted that the peak dry-well temperature is shown to exceed the shell design value by 9^{0}F at the original power and 11^{0}F for the second uprate. However, these "peak" temperatures apply only at the beginning of the accident (for about 20 sec); thus the dry-well temperature increase was not considered a threat to the shell structure. Nevertheless, the salient point to note is the global decrease in containment margin with increased power level.

Table 3-7. Hatch Unit-1Reactor Vessel Margins for DBA-LOCA Conditions

Power Level, MWt	Predicted Stress, ksi	Residual Margin, %
Vessel Shroud at Support Weld (Design Limit = 15.28 ksi)		
Original = 2436	8.95 ksi	41.4
1st Uprate = 2558	9.05 ksi	40.8
2nd Uprate = 2763	---	---
Vessel Shroud at Head Bolts (Design limit = 69.9 ksi)		
Original = 2436	52.7 ksi	24.6
1st Uprate = 2558	53.0 ksi	24.2
2nd Uprate = 2763	---	---
Vessel Access Hole Cover Plate at Bolts (Design Limit = 107.7 ksi)		
Original = 2436	Original Cover was welded	---
1st Uprate = 2558	64.5 ksi	40.1
2nd Uprate = 2763	90.0 ksi	16.4
Jet pump at Diffuser Base (Design limit = 50.7 ksi)		
Original = 2436	31.5 ksi	37.9
1st Uprate = 2558	34.8 ksi	31.4
2nd Uprate = 2763	34.9 ksi	31.2

Table 3-8. Hatch Unit-1 Containment Margins for DBA-LOCA Conditions

Power Level, MWt	Parameter Value	Residual Margin, %
Peak Dry-well Pressure (Design Limit = 56 psig/Max.=62 psig)		
Original = 2436	47.9 psig	14.5
1st Uprate = 2558	49.6 psig	11.4
2nd Uprate = 2763	50.5 psig	9.8
Peak Dry-well Gas Temperature (Design Limit = 281 °F)		
Original = 2436	290 °F (for short time only)	Exceeds design limit for short time
1st Uprate = 2558	292 °F (for short time only)	Exceeds design limit for short time
2nd Uprate = 2763	293 °F (for short time only)	Exceeds design limit for short time
Peak Suppression Pool Temperature (Design Limit = 281 °F)		
Original = 2436	198 °F	29.5
1st Uprate = 2558	202 °F	28.1
2nd Uprate = 2763	208 °F	26.0

3.4 Summary

Results presented here give a brief overview of margin trends for the Hatch plant associated with the two power uprates. The most frustrating aspect of this examination was the difficulty in obtaining self-consistent information with regards design parameters of interest. For example, although a re-examination of DBA-LOCA stress loads is stipulated for power uprates under 10CFR50.92 requirements, often the component stress predictions summarized in the licensee's Uprate Safety Analysis Report (SAR) are for different components then analyzed in the original FSAR, or if for the same component not at the same location. Likewise, thermal/mechanical models to predict stress loads at the different power levels may involve changes in analysis methods, or say alterations in thermal-hydraulic characteristics due to fuel designs changes that may accompany the power uprate For these reasons it is often difficult to make a one-to-one comparison, nevertheless some success was achieved. For the parameters investigated, an increase in power generally reveals some decrease in residual margin when compared to design limits. As noted, in some cases the change in margin can be quite substantial. For example investigative results point to a rather dramatic decrease in margin (see Table 3-7) associated with DBA-LOCA stresses to bolting of the vessel access cover plate. Results indicate a predicted load of 64.5 ksi at the first power uprate, and associated residual margin of 40.1-% compared to the design limit of 107.7 ksi. The residual margin is reduced to only 16.4-% at the second uprate, which largely stems from the fact that blowdown stresses at the second uprate increases to 90 ksi. This reduction in stress margin is quite dramatic, when compared to the 8-% power increase between these two uprates. In other cases, the change in margin with a power is indicated to be minimal, which in general stems from the fact that the parameter in question (e.g. stress, temperature, pressure, etc) remains well below the design limit.

Finally it is noted that in the examination of margins for power uprates, it was assumed that design limits remain constant over the period of power uprating. This however may not be the case, as one might expect some degree of component degradation and reduction in design limits owing to accumulated fatigue effects associated with thermal or mechanical cycling, material loss due to corrosion, or stress-assisted cracking. Reductions in design limits were not accounted for here, but do factor into assessments of passive system and component life as part of license renewal examinations, which are considered in the next chapter.

3.5 References

1. Southern Co., *Extended Power Uprate Licensing Submittal-1995: Edwin I. Hatch Nuclear Power Plant,* (January 1995).

2. Southern Co., *Extended Power Uprate Licensing Submittal-1997: Edwin I. Hatch Nuclear Power Plant,* (August 1997).

3. U. S. Nuclear Regulatory Commission, *Safety Evaluation Report: Edwin I. Hatch Nuclear Plant, Unit No. 1*, Docket # 50-321, Control #: LTR, (May 11, 1973).

4. U. S. Nuclear Regulatory Commission, *Safety Evaluation Report: Edwin I. Hatch Nuclear Plant, Unit No. 2*, NUREG-0411 , (1978).

5 GE Nuclear Energy, *Power Uprate Safety Analysis Report for Edwin I. Hatch Plant Units 1 & 2,* GE Proprietary Document: NEDC-32405P, (Dec. 1994).

6. GE Nuclear Energy, *Extended Power Uprate Safety Analysis Report for Edwin I. Hatch Plant Units 1 & 2,* GE Proprietary Document: NEDC-32749P, (July 1997).

4. POTENTIAL MARGIN REDUCTIONS FOR PLANT LIFE EXTENSION

In addition to power uprates, industry is aggressively moving toward the goal of maximizing investment recovery from its aged population of nuclear power plants. Of the approximately 100 nuclear units currently in operation, upwards of 80 may apply for life extensions beyond their current 40-year license, including the License Renewal Application (LRA) of Feb. 2000 for the Edwin Hatch Units 1 & 2. Here we assess the implications of license renewal as it relates to potential reductions in plant safety margins and again use the Hatch plant as the basis for our assessment. First however, a brief overview is presented of the LAR process and primary safety issues involved; we then go on to estimate potential margin reductions related to the Hatch plant life extension.

4.1 Overview of the License Renewal Process

Plant renewal application requirements and NRC review considerations are governed by the License Renewal Rule specified in 10CFR/Part-54. The hart of the renewal application is the so-called *Integrated Plant Assessment (IPA)* of structures and components requiring aging management review (AMR) and oversight. The purpose of the IPA is to demonstrate that the effects of aging on passive systems, structures, and components for the plant will be managed by the licensee in satisfactory manner so that level of safety during the period of extended operation is consistent with the Current License Basis (CLB). It should be noted that the AMR process applies only to passive systems and components that perform there intended function without moving parts or without a change in configuration, and that are not subject to periodic replacement. Active components are generally not subject to the AMR process, since such equipment is considered to be adequately monitored/maintained by existing surveillance and maintenance programs. Thus, no additional requirements are placed on active components for the LRA; although active equipment surveillance/maintenance programs are required to be continued throughout the entire period of plant operation.

Passive systems, structures, and components (SSC) within the scope of LRA review include all safety-related SSCs relied upon to function during and following design-basis events. For example the integrity of the reactor coolant pressure boundary and containment must be demonstrated, as well as the capability to prevent or mitigate the consequences of accidents which could result in potential off-site exposures. Any non-safety-related systems which are required to assure performance of safety-related SSCs are also included in the aging review process, including systems for fire protection, protection form the effects of pressurized thermal shock (10CFR50.61), anticipated transients without scram (10CFR50.62), and station blackout (10CFR50.63).

NRC requires that each LRA contain an integrated plant assessment (IPA) which identifies all passive systems, structures and components subject to aging management. Examples of such structures and components include (but not limited to) the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category-I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, ,switchgear, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies. For each, the licensee must demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained during the complete period of extended operation and be consistent with the CLB. If found satisfactory, the renewal license will be issued for a fixed period of time, which is the sum of the additional amount of time beyond the expiration of the operating license (not to exceed 20 years) that is requested in a renewal application plus the remaining number of years on the operating license currently in effect. The term of any renewed license may not exceed 40 years. Each plant renewal application is subject to review by the Advisory Committee on Reactor Safeguards (ACRS) for a review. A principal concern of the ACRS in its review to date of LRA has been potential reductions in design basis "margins" for renewal plants, particularly in regards to the total risk impact or margin reductions for multiple licensing actions of aged plants, that is plant life extensions in combination with power uprates, requests for a longer fuel cycle at ever higher burnups, reduced inspections, etc.

Finally it is noted that a principal requirement of a license renewal application is what is referred to as the time-limited aging analyses (TLAAs). Time-limited aging analysis (TLAA) are plant-specific analyses to demonstrate, through acceptable engineering principals, potential degradation of passive systems, structures, and components owing to the corrosive/radiation environment associated with operation of the nuclear plant over its extended license period. Such aging/degradation analysis should include, but are not limited to, an assessment of material loss from components and structures via corrosion, wear, or other processes; evaluation of changes in material micro-properties such as loss of toughness, yield strength or ductility; changes in structure or component macro-properties such as pre-stress properties, settlement, or cracking; loss of dielectric properties; etc. Under 10CFR54.21stipulations, TLAA calculations must be shown to be valid for the period of extended operation. An examination of these TLAA calculations, largely forms the basis for our estimation of the types of margins potentially impacted by plant life extension. Again, we use the Edwin Hatch plant as our case study.

4.2 Overview of Time-Limited Aging Analyses (TLAA)

Pursuant to 10CFR54.21, a license renewal applicant is required to provide a listing of plant-specific TLAA that has been performed and cite supporting documentation of such calculations. This listing of TLAAs should be of sufficient detail to identify the type of calculations performed, applicable national codes and standards, and summarize TLAA calculational results. A good example is provided by an overview of TLAA for reactor vessel degradation via neutron embrittlement.

During plant service, neutron irradiation reduces the fracture toughness and ductility of ferritic steel in the reactor vessel; thus, TLAA calculations to cover the extended period of operation must be performed to demonstrate that the reactor vessel has adequate fracture toughness and ductility to prevent brittle failure during normal and off-normal conditions. TLAA calculation procedures are stipulated in the ASME Boiler and Pressure Vessel Code to estimate fracture toughness and ductility, and include estimation procedures for (a) upper-shelf energy, (b) pressurized thermal shock (PTS) for pressurized water reactors (PWRs), (c) heat-up and cool-down pressure-temperature limits to assure ductility, and (b) boiling water reactor (BWR) Vessel and Internals Project (VIP) VIP-05 analysis for elimination of circumferential weld inspection and analysis of the axial welds. The NRC staff's findings on the adequacy of these TLAA evaluations are documented in the NRC Safety Evaluation Report (SER) for the renewal application.

In the following section we examine results of several TLAA calculations performed as part of the Edwin Hatch License Renewal Application (LRA), which are used in our estimation of the types of margins potentially impacted by plant life extension.

4.3 Estimation of Margin Reductions from Hatch TLAA

In Feb. 2000 the Southern Co. submitted its LRA request for both Edwin Hatch units 1 and 2 for a period of 20 years beyond the current license expirations of August 6, 2014 for Unit 1 and June 13, 2018 for Unit 2. The operating license for Unit-l was issued in 1974 and for Unit-2 in 1978. Each unit consists of a General Electric (GE) boiling water reactor (BWR) nuclear steam supply system, currently licensed to generate 2558MWt.

Southern Co. first performed a review of design analyses and calculations for each unit to determine the scope of the passive system. structures, and components for which TLAA evaluations were required to meet criteria of 10CFR54. The review was performed by the Southern Co. in conjunction with consulting services of the original architect engineer for the plant (Bechtel Power Corporation) and the nuclear steam supply system vendor (GE-General Electric Company). Independently, Southern Co. also performed a review of the Current Licensing Basis (CLB) for time-limited or age-related statements that met the criteria or 10CFR 54. Table 4.1 summarize the primary TLAA performed as part of the Hatch license renewal application. Results of several such TLAA calculations are reviewed here to assess the impact of aging on potential margin reductions. Specifically the fatigue/stress analyses for the torus structure and nozzle connections (Item-2, Table 4.1) and calculations for the nil-ductility pressure-temperature limits (Item-7, Table 4.1) for the reactor coolant pressure boundary and vessel due to radiation embrittlement are examined.

Table 4.1 Summary of Time-limited Aging Analysis for the Hatch License Renewal

1. Piping stress analyses are provided that consider thermal fatigue cycles defined by the life of the plant for 60 years of operation.
2. Fatigue/stress analyses are provided for the torus structure and nozzle connections for 60 years of operation.
3. Piping wall thickness calculations are given that develop acceptable as-measured criteria for pipe walls based upon an anticipated corrosion rate that, in turn, is based upon the life of the plant for 60 years of operation.
4. Calculations of the corrosion allowance for the reactor vessel for 60 years of operation are provided.
5. Environmental equipment qualification calculations that qualify electrical components for 40 years are extended for 60 years of operation.
6. A containment penetration structural analysis is given that assumes a number of pressurization cycles over the extended 60 years of operation for the plant.
7. Calculations are provided for the nil-ductility temperature (pressure-temperature limits) for the reactor coolant pressure boundary and vessel materials due to radiation embrittlement. The results of the evaluation for 60 years of operation are provided.
8. Estimates are given for the end-of-life equivalent Charpy upper-shelf energy margin for 60 years of operation are provided.
9. Analyses are provided to demonstrate the acceptability of a technical alternative to the ASME Boiler Code requirements for inspection of reactor pressure vessel circumferential welds for the extended 60 years of operation.
10. Change in the anticipated operating cycles of the main steam isolation valves (MSIVs) from the number of cycles assumed for 40 years in the original Hatch FSAR are augmented for 60 years of operation.

4.3.1 Hatch Piping Fatigue Usage Estimates

Table 4-1 indicates that the license renewal rule requires that licensee perform stress analyses for critical plant piping which is subjected to cyclic loading; specifically thermal fatigue cycle analysis is required for critical piping to estimate the total number of thermal cycles such piping may experience over the full 60 years of extended operation. This requirement stems from experience with operating plants, which reveal numerous fatigue failures of LWR piping components, nozzles, valves, and pumps. As discussed in NUREG/CR-5704, in most cases such fatigue failures have been associated with cyclic thermal or mechanical/vibration loads. Cyclic loading on components occur because of changes in the mechanical and thermal loadings as the system goes from one set of pressure, temperature, moment, and force loading to another. The effect of these loadings can be aggravated by component corrosion due to exposure to high-temperature aqueous environments. Fatigue cracks have been observed in pressurizer surge lines in PWRs, in feedwater lines and nozzles in BWR, in PWR steam generators, etc. Such cracks have been attributed to corrosion fatigue (NRC-IE Bulletin: 79-13) or strain induced corrosion cracking caused by cyclic loading associated with thermal stratification during startup and shutdown.

Although the ASME Boiler and Pressure Vessel Code contains design rules to account for fatigue effects on steel piping and other reactor components, these rules were not originally intended to address the effects of the coolant environment on fatigue life. Specifically the design of older plants were based on ASME code methods that did not account for environmental effects (corrosion, etc) on fatigue; thus uncertainty exists concerning the effects of environment on fatigue resistance of materials used in operating reactor plants. The License Renewal Rule specifically requires a re-evaluation of fatigue limits as part of the Time Limited Aging Analysis (TLAA), for certain passive systems, structures, and components which may be subject to fatigue induced degradation.

The TLAA fatigue requirements are essentially estimates of the total number of stress cycles, based on plant-specific operational and historical data, that a component or system might reasonably be expected to experience during its 60 year extended life. Such TLAA fatigue estimates are formulated in terms of the so-called "*cumulative usage factor*" (CUF), which essentially involves an assessment of the stress impact of various cyclic operational and off-normal transients which contribute to the total cumulative fatigue to that specific component or system. In its most simple form CUF can be expressed as:

$$CUF = N_{OBE}/f_1 + N_{Scram}/f_2 + N_{Startup}/f_3 + \ldots\ldots N_{other}/f_n$$

where

N_{OBE} = number of operating basis earthquakes
N_{Scram} = number of reactor scrams
$N_{startup}$ = number of reactor startups
N_{other} = other operational transients (i.e boltups, relief valve lifts, etc.)

and f_1, f_2, $f_{3,}$ and f_n are scaling factors indicative of the maximum number of allowable cycles for a particular transient or event and its associated impact on fatigue. The ASME Code requires that Class-1 components have an initial design predicted CUF less than or equal to 1.0. When the extended license term is considered, NRC requires that Class-1components also have a CUF less than one. If CUF is found to be greater than 1.0, then that component is subject to special inspection considerations or other remedial action during the license extension period.

For the Hatch plant, the licensee, in conjunction with Bechtel, GE, and various subcontractors, estimated the cumulative usage factor (CUF) for all Class-1 piping and components at its 1998 condition, as well as at the end of 40 years of operation and for the full 60 year plant life. The CUF estimates are based on a review of the operating history for each unit and include estimates of the total startup events, scrams, shutdowns, boltup operations, etc. Results of the Hatch TLAA piping fatigue analysis are summarized in Table 4-2. As indicated, certain components with minimal cycling, such as the core spray piping are predicted to have rather low CUF values. On the other hand, the feedwater and steam condensate drainage piping have predicted CUF values approaching one after 60 operational years, due to the fact that they experience cyclic coolant temperatures changes associated with normal startup and shutdown events, as well anticipated operational reactor scrams. For the feedwater piping, estimated CUF values increase from about

0.4 after about 20 years operation, to 0.6 at 40 years, and to 0.83 at the end of the 60 year extension period.

Table 4-2. Piping Fatigue Usage Estimates for Hatch Renewal (Ref. 3).

		Cumulative Usage Factor, CUF		
Component	**Unit**	**CUF at1998 (Apprx. as 20 yr)**	**CUF at 40 years**	**CUF at 60 years**
Residual Heat Removal Suction Piping	2	0.3644	0.5704	0.772
Reactor Vessel Equalizer Piping	1	0.1265	0.5188	0.6385
Core Spray Replacement Piping	1	0.0684	0.1610	0.1860
Feedwater Piping	2	0.3970	0.6111	0.8312
Standby Liquid Control Piping	1	0.0238	0.2371	0.2508
Feedwater (FW), High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), and Reactor Water Cleanup (RWCU) Piping	1	0.4264	0.5589	0.7224
Steam Condensate Drainage Piping	2	0.4859	0.6632	0.8856
Main Steam Piping (Line B)	1	0.0528	0.0747	0.1020
Main Steam Piping (Line D)	2	0.0087	0.0156	0.0226

Notes:

CUF-98 = Cumulative Usage Factor as of 1998 (date of most recent RPV cycle counts).
CUF-40 = Cumulative Usage Factor for forty years.
CUF-60 = Cumulative Usage Factor for sixty years.

Initial criticality for Unit-1= 9/12/74; thus, N-98 represents 24 years of operation for Unit-1.
Initial criticality for Unit-2= 7/04/78; thus, N-98 represents 20.5 years of operation for Unit-2.

Similar to our assessment of "margin changes" for power uprates, we also attempt here to estimate potential margin reductions associated with plant life extension. Since "margin" is a rather general term, any "quantitative" evaluation of its value is largely based on user definition. In its most general sense, margin can simply be expressed as the difference between the actual parameter value versus some limit criteria, usually the design limit, thus:

Margin = Design Limit - Actual

From the discussion above, it is noted that the ASME Code requires that Class-1 components have a design predicted CUF less than or equal to 1.0 at the end of the intended period of operation; where CUF=1 implies a design limit to assure against fatigue failure. We use this definition to estimate a *fatigue residual margin* (or simply 'residual margin') for components to 60 years plant life extension, based on the TLAA piping fatigue estimates presented above; i.e:

$$\boxed{\text{Residual Margin} = 1.0 - \text{CUF}}$$

Table 4-3 summarizes fatigue margin estimates for Hatch. Predictions show that although feedwater and steam condensate drainage piping are most sensitive to fatigue, which is largely due to the number of thermal transients and the intensity of the thermal loads they experience, nevertheless the residual fatigue margin is estimated to be about 39-% and 34-% respectively at the end of 40 years plant life. However, TLAA analysis indicate that the residual fatigue margin for such piping are reduced considerably after 60 years of plant operation, namely to 17-% for feedwater piping and only 11-% residual margin for the steam condensate piping. It is also noted from inspection of Figure 4-1, that the change in the estimated cumulative usage factor (CUF) with time is different for each piping component and can exhibit non-linear behavior. As indicated the CUF for the steam condensate drain pipe is shown to increase with time, indicative of an acceleration of fatigue degradation with time. On the other hand, the vessel equalizer piping is shown to exhibit a less dramatic increase in CUF with time, although still increasing with plant operating time.

Table 4-3. Residual Margin Estimates from Piping Fatigue Usage Analysis for Hatch Renewal (CUF at two significant figures)

Component	Unit	CUF at 40 years	Residual Margin at 40 years, %	CUF at 60 years	Residual Margin at 60 years, %
Residual Heat Removal Suction Piping	2	0.57	43-%	0.77	23-%
Reactor Vessel Equalizer Piping	1	0.52	48-%	0.64	36-%
Core Spray Replacement Piping	1	0.16	84-%	0.19	81-%
Feedwater Piping	2	0.61	39-%	0.83	17-%
Standby Liquid Control Piping	1	0.24	76-%	0.25	75-%
Feedwater (FW), High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), and Reactor Water Cleanup (RWCU) Piping	1	0.56	44-%	0.72	28-%
Steam Condensate Drainage Piping	2	0.66	34-%	0.89	11-%
Main Steam Piping (Line B)	1	0.08	92-%	0.10	90-%
Main Steam Piping (Line D)	2	0.016	>98-%	0.02	98-%

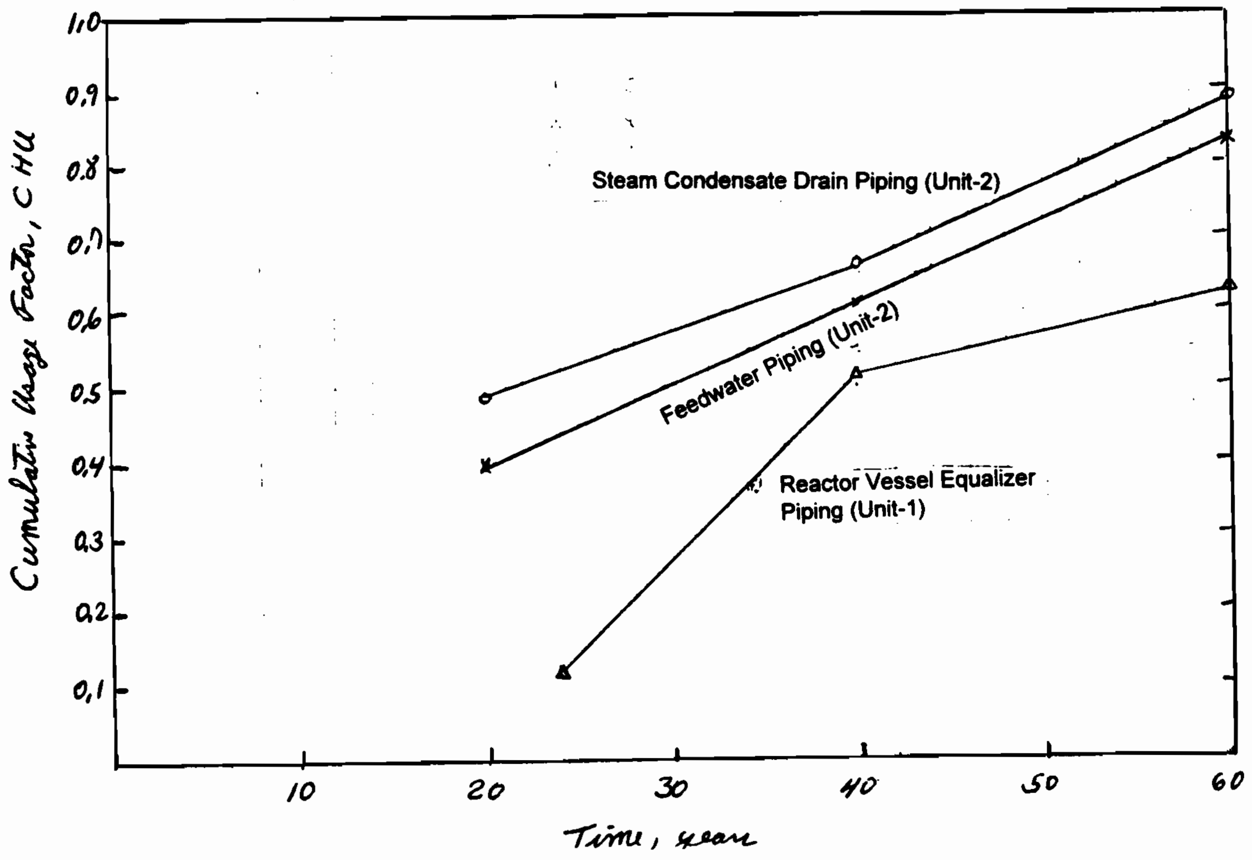


Figure 4-1. Predicted Cumulative Usage Factor (CHU) versus plant operation time (t) for several Hatch plant Class-1 pipes.

4.3.2 Hatch Torus Fatigue Usage Estimates

Similar to the cumulative usage factor (CUF) estimates of cyclic loadings of Class-1primary coolant piping and other pressure boundary components, the license renewal rule also requires CUF estimates for the torus region of BWRs, including associated piping, nozzle, and safety relief valve (SRV) components. This requirement is indicated as item-2 in Table 4-1. As part of the Hatch TLAA assessment, CUF estimates were made for torus, including the vessel, the SRVs, nozzles, and attached piping penetrations. Different CUF equations were developed for the different locations and components because of variances in thermal/cyclic loadings or because of differences in the ability to track (count) loading events at the different locations.

To estimate the number of count events that contribute to fatigue loading of the Hatch torus for each unit, a review was first conducted the prior power uprate reports, as well as LERs (License Event Reports), scram and alarm reports, and annual operating reports. This historical data was used in the development of the torus CUF equations. Results are summarized in Table 4-3 for the torus vessel at two time periods indicated in Ref. 4-4, that is at 05-31-1999 and at the end of the license renewal period of 60 years. For the Unit-1 torus vessel, CHU is estimated to be 0.35 as of 05-31-1999, while CHU is 0.214 for Unit-2 (at 05-31-1999). These values are shown to increase to 0.955 for Unit-1 and 0.799 for Unit-2 at the end of the 60 year renewal period. The residual margin for fatigue shown in Table 4-3 is estimated in a similar manner as that for the primary piping, i.e.:

Residual Margin = 1.0 - CHU-X

where CHU-X is the estimate of the cumulative usage factor at X-years of operation. The residual margin for the Unit-1 torus vessel is shown to be reduced considerably after 60 years of plant operation, namely to only 4.5-% margin based on ASME fatigue code allowance guidelines for total cumulative usage cycles. For Unit-2, a larger margin of 20-% is indicated at the end of the 60 year plant extension, due primarily to the shorter total period of operation (about 4 years less than Unit-1).

Table 4-4. Torus Vessel Fatigue Usage and Residual Margin Estimates for Hatch License Renewal

	CUF @ 5/31/99	Residual Margin @ 5/31/99, %	CUF @ 60 years	Residual Margin @ 60 years, %
Unit-1	0.350 @ 24.6yr	65-% @ 24.6yr	0.955	4.5-%
Unit-2	0.214 @ 20.9yr	78.6-%@ 20.9yr	0.799	20.1-%

Initial criticality for Unit-1= 9/12/74; thus 5/31/99 represents about 24.6 years of operation for Unit-1.
Initial criticality for Unit-2= 7/04/78; thus 5/31/99 represents about 20.9 years of operation for Unit-2.

4.3.3 Hatch Coolant Pressure Boundary P-T Limits

General Design Criterion 14 (GDC-14: Reactor Coolant Pressure Boundary) of 10CFR50 App.-A, requires that the reactor coolant pressure boundary be designed, fabricated, and tested in order to assure the low probability of pressure boundary failure or abnormal leakage. GDC-31 (Fracture Prevention of Reactor Coolant Pressure Boundary) additionally requires that the reactor coolant pressure boundary be designed with sufficient margin to assure that when stressed under operating and maintenance/testing conditions, the pressure boundary behaves in a non-brittle manner. Likewise, GDC-32 (Inspection of Reactor Coolant Pressure Boundary) requires an appropriate materials surveillance and testing programs for the reactor vessel belt-line region. These design criteria are satisfied by the imposition of pressure-temperature limits on the reactor coolant pressure boundary during reactor operation, abnormal transients, and testing/surveillance procedures, which are reviewed under procedures specified in Section 5.3.2 of the Standard Review Plan (SRP, NUREG-0800). The bottom line of these requirements is the assurance that the structural materials constituting the reactor coolant pressure boundary possess adequate fracture toughness to resist rapidly propagating failure and act in a non-brittle manner when stressed under operating, maintenance, testing, and anticipated operational conditions.

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The fracture toughness requirements for ferritic materials for the pressure retaining components of the reactor coolant pressure boundary (RCPB) are specified by criteria outlined in App.-G of the ASME Boiler and Pressure Vessel Code. The code specifies the methodology to determine an adjusted reference temperature (ART) to account for irradiation induced loss of ductility of steel materials. The ART is defined as the sum of the initial unirradiated temperature to assure ductility (reference nil-ductility temperature-RNDT), a mean value of an adjustment in this reference temperature to account for loss of ductility due to irradiation induced steel embrittlement, and a margin term to account for uncertainties in copper and nickel content of the steel, uncertainties in irradiation fluence, as well as uncertainties in calculational procedures. The code includes procedures to calculate a pressure-temperature map to assure adequate fracture toughness over a range of conditions, including procedures to assure fracture-toughness properties of materials resulting from neutron irradiation and thermal cycling (see also Regulatory Guide 1.99: Effect of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials).

As part of the FSAR (Final Safety Analysis Report) any licensee for a commercial nuclear power plant must submit temperature-pressure limits for anticipated operational conditions of the plant, which includes upset conditions, startup and shutdown procedures. These operating pressure-temperature limit curves must show the maximum permissible pressure at any temperature from cold shutdown conditions to full pressurization conditions. Reactor vendors have developed computer codes to perform the necessary calculations, because thermal stresses must be included, and hand calculations of even moderate sophistication are very time consuming. Either allowable pressure at a given temperature, or allowable temperature at a given pressure can be calculated. It is usually more convenient to calculate allowable minimum temperature.

As part of the effort to evaluate the reactor pressure vessel (for both Hatch 1 and 2) for the license renewal term, the effects of irradiation on the core belt-line region have been evaluated. The purpose of this evaluation was to provide input to the pressure-temperature (P-T) operating limits, as required by 10CFR50, Appendix G. The evaluation, was performed for the expected lifetime of 54 effective full-power years (EFPY) of extended life for both units. In addition, intermediate P-T limit predictions were generated for Unit-1 at 36, 40, 44, 48, and 54 EFPY, due to the expected irradiation shift for the Hatch-1 vessel.

One of the major considerations for extended life of the reactor pressure vessel (RPV) is irradiation of the core region, or belt-line. The effect of irradiation is to shift the reference nil-ductility transition temperature (RFNDT) of the belt-line materials. This shift must be evaluated in order to conform to the requirements of 10CFR50/ Appendix-G. To encompass the effects of irradiation for the license renewal term, a maximum lifetime of 54 EFPY was used to incorporate the effects of irradiation embrittlement on the pressure-temperature (P-T) limits (curves) for the reactor coolant pressure boundary (RCPB). The P-T limit predictions (curves) were developed in the form of reactor vessel steam dome pressure versus minimum vessel metal temperature, for both the belt-line and other non-belt-line regions of the RCPB. These non belt-line predictions encompass regions of stress discontinuity such as nozzles, penetrations, and flanges which affect the P-T curves. The non belt-line limits are based on generic analyses which are adjusted to the maximum reference temperature of nil ductility transition (RTNDT) for the applicable Hatch 1 or 2 vessel components. Predicted P-T limits from time-limited ageing analysis for the Hatch Unit-1 plant are given in Table 4-4 for *non-nuclear* heatup/cooldown conditions at 100 ^{o}F/hr, while Table 4-5 presents similar information at *core critical* operation. As indicated, ever higher material temperatures are required to retain adequate ductility and offset the cumulative impact of irradiation induced material embrittlement associated with increased plant lifetime, i.e. effective full-power operation years (EFPY). For example Table 4-4 indicates a minimum temperature of 265.2^{0}F at the belt-line region (mid-region of vessel where neutron fluence is highest) to assure material ductility at 36 EFPY (at operational pressure of about 1000 psig), which increases to 291.4^{0}F at 54 EFPY. These values can be compared with a significantly lower temperature limit for the bottom head region, which is shown to remain at 158.7^{0}F even at the extended plant life of 54 EFPY, which is due to the nil impact of irradiation damage to the bottom head (low neutron fluence at this location). A similar trend is shown in Table 4-5 for core-critical conditions, that is an increase in the minimum temperature to offset material irradiation embrittlement effects with increased plant operational time.

Table 4-4. Time Limited Aging Analysis Predictions for Hatch Unit-1 Reactor Coolant Pressure Boundary

Minimum temperature prediction to assure adequate ductility and fracture toughness of the reactor coolant pressure boundary (RCPB), for <u>non-nuclear</u> heatup/cooldown conditions versus effective full-power years (EFPY).

Non-nuclear heatup/cooldown rate at 100 ^oF/hr	Operational Pressure, 1000 psig		Over-Pressure, 1200 psig	
	Bottom Head	Belt-line	Bottom Head	Belt-line
Min. Temperature @ 54 EFPY	157 ^oF	291.4 ^oF	172.4 ^oF	306.4 ^oF
Min. Temperature @ 48 EFPY	157 ^oF	283.6 ^oF	172.4 ^oF	298.6 ^oF
Min. Temperature @ 44 EFPY	157 ^oF	277.6 ^oF	172.4 ^oF	292.9 ^oF
Min. Temperature @ 40 EFPY	157 ^oF	271.7 ^oF	172.4 ^oF	286.7 ^oF
Min. Temperature @ 36 EFPY	157 ^oF	265.2 ^oF	172.4 ^oF	280.2 ^oF

Table 4-5. Time Limited Aging Analysis Predictions for Hatch Unit-1 Reactor Coolant Pressure Boundary

Core-critical operation with heatup/cooldown rate at 100 ^oF/hr	Operational Pressure, 1000 psig	Over-Pressure, 1200 psig
	Reactor Pressure Vessel	Reactor Pressure Vessel
Min. Temperature @ 54 EFPY	331.4 ^oF	346.4 ^oF
Min. Temperature @ 48 EFPY	323.6 ^oF	338.6 ^oF
Min. Temperature @ 44 EFPY	317.9 ^oF	332.9 ^oF
Min. Temperature @ 40 EFPY	311.7 ^oF	326.7 ^oF
Min. Temperature @ 36 EFPY	305.2 ^oF	320.2 ^oF

Although the above P-T estimates provide a signature of the impact of increased irradiation exposure on loss of material ductility, with ever higher temperatures (at a specific pressure) required to assure ductility of the steel pressure vessel at the increased neutron that accumulates with increased plant life, it is difficult to ascribe a "margin" value to such temperature-pressure requirements. Results from the piping and torus TLAA fatigue analysis could more easily be expressed in terms margin, since the NRC license renewal requirements specify that the cumulative usage factor (CUF) can not exceed 1 for any component at the end of the intended period of operation; where CUF=1 implies a design limit to assure against fatigue failure. Thus we were able to use this stipulation on CUF to estimate a residual fatigue margin for components to 60 years plant life extension, i.e:

$$\boxed{\text{Residual Margin} = 1.0 \ - [\text{CHU-X}]}$$

where CHU-X is the estimate of the cumulative usage factor at X-years of operation. In most other cases we were able to define marge as the difference between the actual parameter value versus some limiting criteria, usually the design limit, i.e.:

$$\boxed{\text{Margin} = \text{Design Limit} - \text{Actual}}$$

To apply the above margin definitions to the P-T limits requires some limiting condition on temperature, but the P-T temperature estimates are in themselves limiting conditions. However, it is noted from inspection of Table 4-4 that the temperature for the bottom head region remains constant (158.7^{0}F at 1000 psig and 172.4^{0}F at 1200 psig) over the full extended plant life of 54 EFPY, which is due to the nil impact of irradiation damage to the bottom head (low neutron fluence) at this location. We thus make use of the bottom-head temperature limit as a benchmark signature of margin.

Here we shall define the term "Relative Residual Margin" from P-T limits in terms of an increase in temperature to overcome the irradiation damage effects, over and above the bottom head temperature requirement. The term *'relative'* is used to signify the ductility temperature requirements relative to that for the bottom head. This definition is essentially a measure of the excess P-T temperature limit required to compensate for irradiation damage at high fluence areas, compared to the P-T temperature limit at the bottom head which experiences little such irradiation embrittlement.

$$\text{Margin(@ 1000 psig)} = 157 - T_{limit}\text{ (@ EFPY)}$$

$$\text{Relative Residual Margin (@ 1000 psig)} = 1 - \frac{T_{limit}\text{ (@ EFPY)} - 157}{157}$$

Similarly for over-pressure conditions at 1200 psig, the margin is expressed as:

$$\text{Margin}(@\ 1200\ \text{psig}) = 172.4 - T_{limit}\ (@\ \text{EFPY})$$

$$\text{Relative Residual Margin}\ (@\ 1200\ \text{psig}) = 1\ - \frac{T_{limit}\ (@\ \text{EFPY}) - 172.4}{172.4}$$

Table 4-6 summarizes residual margin estimates for the reactor vessel belt-line region at two pressures for non-nuclear vessel heatup, while Table 4-7 shows similar results for core-critical conditions. A trend of decreased residual margin is indicated with increased effective full-power years (EFPY) of operation. Of particular note is significant increase in the vessel temperatures required to assure ductility at the end of plant life extension at 60 years (EFPY = 54 years). Using the above definition of 'relative residual margin', results show a residual margin of 21-% at 36 EFPY for non-nuclear heatup, which reduces to only 4.8-% residual margin at 54 EFPY, as shown in Table 4-6. For core-critical heatup the predicted residual margin is considerably less, with essentially nil margin by our definition at the end of the life-extension period of 54 EFPY, as indicated in Table 4-7.

Table 4-6. Time Limited Aging Analysis Predictions for Hatch Reactor Vessel At Non-Nuclear Heatup Conditions

Non-nuclear heatup/cooldown rate at 100 °F/hr	Belt-line @ 1000 psig		Belt-line @ 1200 psig	
	P-T Limit	Relative Residual Margin, %	P-T Limit	Relative Residual Margin, %
Min. Temperature @ 54 EFPY	291.4 °F	14.4	306.4 °F	4.8
Min. Temperature @ 48 EFPY	283.6 °F	19.4	298.6 °F	9.8
Min. Temperature @ 44 EFPY	277.6 °F	23.2	292.9 °F	13.4
Min. Temperature @ 40 EFPY	271.7 °F	26.9	286.7 °F	17.4
Min. Temperature @ 36 EFPY	265.2 °F	31.1	280.2 °F	21.5
Nil-irradiation damage T-limit taken to be bottom head temperature of 157°F				

Table 4-7. Time Limited Aging Analysis Predictions for Hatch Reactor Vessel At Core-Critical Conditions

Core-critical operation with heatup/cooldown rate at 100 ^{0}F/hr	Belt-line @ 1000 psig		Belt-line @ 1200 psig	
	P-T Limit	Relative Residual Margin, %	P-T Limit	Relative Residual Margin, %
Min. Temperature @ 54 EFPY	331.4 ^{0}F	7.8	346.4 ^{0}F	0; signifies more than doubling of nil irradiation damage T-limit of 172.4^{0}F for bottom head
Min. Temperature @ 48 EFPY	323.6 ^{0}F	12.3	338.6 ^{0}F	3.6
Min. Temperature @ 44 EFPY	317.9 ^{0}F	15.6	332.9 ^{0}F	6.9
Min. Temperature @ 40 EFPY	311.7 ^{0}F	19.2	326.7 ^{0}F	10.5
Min. Temperature @ 36 EFPY	305.2 ^{0}F	23.0	320.2 ^{0}F	14.3
Nil-irradiation damage T-limit taken to be bottom head temperature of 172.4^{0}F				

4.4 Summary

Results presented here give a brief overview of margin trends for several passive components for which time limited aging analysis (TLAA) was performed for the Hatch plant license renewal application. As would be expected, TLAA results show the clear trend of margin decease with increased plant operational time, independent of 'margin definition'. The cumulative usage factor (CUF) estimates for cyclic loadings of Class-1primary coolant piping and pressure boundary components are considered a more direct signature of margin reduction or residual margin. CUF results plainly demonstrate the trend of reduced margins at the plant renewal period of 60 years. Indeed for some passive pressure boundary components the residual margin at the end of the 60-year extension period is quite minimal, for example only 11-% residual margin at for the steam condensate drainage piping (see Table 4-3). An even smaller residual margin is estimated for the torus suppression-pool vessel, that is 4-5% for Unit-1 at 60 years end of plant life (see Table 4-4).

4.5 References

1. Southern Company, *Edwin I. Hatch Nuclear Plant License Renewal Application*, Docket: 50-321 and 50-366, (Feb. 2000).

2. U. S. Nuclear Regulatory Commission, *Safety Evaluation Report: License Renewal of the Edwin I. Hatch Nuclear Plant, Units 1 and 2,* Docket: 50-321 and 50-366, (Feb. 2001).

3. Structural Integrity Associates, Inc., *Development of Class-I Piping Fatigue Formulas and Fatigue Usage Estimates for the Hatch Nuclear Power Plant, Units-1 and* 2, Structural Integrity Associates Report, SIR-99-078, (August 1999).

4. O. K. Chopra, *Effects of LWR Coolant Environments on Fatigue Design Curves of Austentictic Stainless Steels,* NUREG/CR-5704, (April 1999).

5. J. Keisler, O. K. Chopra, and W. J. Shack, *Fatigue Strain-Life Behavior of Carbon and Low-Alloy Steels, Austenitic Stainless Steels, and Alloy-600 in LWR Environments,* NUREG/CR-6335, (August 1995).

6. M. A. Khaleel, et al, *Fatigue Analysis of Components fro 60-year Plant Life,* NUREG/CR-6674, (June 2000).

7. Southern Company Services, Inc., *Torus Fatigue Formulas and 60-Yr CUF Projection*, Southern Co. Internal Report, DCR-REA-HT-98674, (Nov. 9, 1999).

5. MARGINS and RISK ANALYSIS METHODS

In this report reductions in margins for power uprates and plant life extension were estimated from changes plant operational and off-normal conditions. A case study was made for the Hatch plant, owing to the fact that it received approval for two power uprates (5-%, 8-%) and is under review for plant renewal. For power uprates, margin estimates were based on licensee provided information regarding changes in operational parameters, i.e. temperatures, pressures, flow rates, as well as predicted off-normal loads (stresses) at uprated conditions. These parameters were then compared with ASME design limits for specific plant components (primary and feedwater piping, allowable bolt stress, etc) to assess impact on margins. For plant renewal, margin trends were estimated for several passive components for which time-limited aging analysis (TLAA) was performed, i.e. estimates of the cumulative usage factor (CUF) for cyclic/fatigue loadings of certain structures and components. Predictions for CUF at 40 and 60 years plant life were compared with the allowable CUF limit of one. For both uprates and plant renewal margin reductions to design and CUF limits were evident. Although results indicate reduced margins for specific plant components and for the individual impact of power uprates and plant life extension, such estimates do not provide a *holistic or integrated* assessment of margin impact for the plant as a whole.

Probabilistic Risk Assessment (PRA) methods provide a structure for an integrated approach to overall plant analysis. As a discipline, PRA is a collection of analysis techniques that serve to identify potential failures of individual components in a complex system of many components, and the consequences of such failures. First developed in the aerospace industry, PRA methods have been adopted for nuclear plant risk analysis. Indeed PRA for nuclear plants have matured to the point that they are now commonly used to identify dominant failure sequences, the consequences (risk) of such failures, guidance for prioritization of maintenance and inspection activities, as well as providing a risk-informed basis for regulatory oversight. It is from the perspective of an integrated assessment of the plant as a whole, that PRA techniques might well be adopted to an assessment of the margin impact for the plant as a whole.

As discussed in the recent ACRS report on the agency's research program [1], although the NRC has set upon a course of making greater use of risk information in the regulatory process, current regulatory reviews of license renewal applications and power uprates are largely being addressed from a deterministic approach and as separate/non-associated actions. Although uprate and renewal reviews include an evaluation of safety related components and systems to assure that current regulatory requirements are satisfied and that such safety equipment perform their intended function; uprate and renewal regulatory reviews are essentially done independently of one another, so that a *holistic or integrated* assessment of the plant stemming from such multiple licensing actions is lacking. There is little question however, that the useful life of nuclear plant systems and components are being consumed by the higher demand imposed by one licensing action after another for the same plant. Vessels are more embrittled at 60 years of life than at 40, mechanical components are closer to their fatigue limits at extended plant life, while higher piping pressures and temperatures associated with power increases leave less margin to design levels and result in higher core inventories of radionuclides. In general plant PRAs do not account for either age related equipment degradation or decreases in margins for components to their design limits owing to uprated

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power conditions. With some development efforts, it is believed that PRA techniques could provide a more integrated assessment of risk owing to aging effects and component margin reductions.

Recently the Swiss Federal Nuclear Safety Inspectorate sponsored a risk study for the Leibstadt BWR-6 plant, where an assessment was made of the risk impact owing to a 14.7-% power increase [2]. Although the impact of margin reductions to design limits for individual safety related components was not explicitly modeled in that study, the impact of higher decay heat and higher fission product inventories associated with the power increase were modeled. Although results indicate only a small increases in CDF (core damage frequency) and LERF (large early release fraction) owing to the higher power level; a 30-% increase in latent cancer effects and land contamination were indicated. This increase in latent cancers and land contamination were attributable to the higher fission product inventory at the uprated power level and the acceleration of events associated with the higher decay heat level, which left less time for operator assisted mitigative actions. This study demonstrates that when metrics other than CDF are considered, there indeed appears to be risk impact owing to higher power levels. It is for this reason that the ACRS has recommended [1] that NRC consider additional criteria to judge changes in risk for power uprates and license renewal. Regulatory judgements based principally on CDF and LERF may lead to a false sense of the safety significance of such licensing actions.

Although the Hatch case study of margin reductions for power uprates and plant life extension indicate a quite different metric of safety impact then CDF or LERF, or for that matter latent cancers or land contamination; nevertheless, the same trend line is indicated.....i.e. some reduction in safety for uprates and renewal. Extension of PRA techniques to incorporate the effects of component aging and margin reductions to design limits, would go a long way in clarifying the totality of safety implications for such licensing actions. This effort is recommended.

References

1. Advisory Committee on Reactor Safeguards, *Review and Evaluation of the Nuclear Regulatory Commission Safety Research Program*, NUREG-1635 (Vol.-4), (May 2001).

2. U. Schmocker, M. Khatib-Rahbar, E. Cazzoli, and A. Kuritzky, *An Assessment of the Risk-Impact of Reactor Power Upgrade fro a BWR-6 Mark-III Plant*, Proc. of PSAM-3 Meeting, Crete, Greece (1997).

6. DISCUSSION, CONCLUSIONS, and RECOMMENDATIONS

Results of a case study for the Hatch-BWR plant indicate evident margin reductions stemming from power uprates and plant life extension. Such margin reductions were estimated from changes in plant operating conditions, stress loads, or cyclic/fatigue analysis for plant components, compared to their design limits specified by the ASME Boiler & Pressure Vessel Code. Power uprates generally result in some increase in core coolant enthalpy, exhibited by higher primary system pressures, temperatures, net coolant through-flow, or some combination thereof. To facilitate higher power output, thermal-hydraulic conditions likewise are altered for balance of plant systems. For plant components that are not replaced or upgraded, such changes generally result in some degradation of component margins to their design temperature/pressure limits. For the Hatch power uprate, the most notable margin impact stems, not from changes in operational thermal-hydraulic conditions, but rather from increased stress loads under design basis/loss-of-coolant accident (LOCA) conditions.

With regards to Hatch plant life extension, margin trends were estimated for several passive components for which time-limited aging analysis (TLAA) was performed. TLAA estimates largely center on estimates of the cumulative usage factor (CUF) for cyclic loadings on passive components, with an allowable limit of one. Estimates for Hatch invariably indicate higher CUF values at the end of 60 years than at 40 years, again indicating margin reductions.

Although this study involved solely an examination of the Hatch plant, similar changes in system conditions can be expected for other plants involving similar licensing actions. Because of such similarities, one is drawn the conclusion of *generic margin reductions* for power uprates and plant life extension; although plant-to-plant variations are expected. Although this conclusion may not be surprising, licensee applications for power uprates do not generally point to such margin reductions. Rather the emphasis of the uprate application centers on discussions of continued safety assurance so long as design limits are not violated. For power uprate, consideration of margin reductions to component design limits, as estimated in this report, are generally not given or at best remain opaque. On the other hand regulatory guidance for license renewal applications stipulate aging analysis (CUF analysis) requirements for passive components; thus margin reductions to the allowable CUF limit of one are clearly evident. A primary recommendation stemming from this investigation, is the need for similar indicators of component margin reductions for uprates. This recommendation is noteworthy, in view of a considerable number of anticipated power uprate requests and in light of the magnitude of the uprates (10-20 %) for an ever-aging fleet of plants.

It should be noted that the margin estimates presented in this case study are for individual components and for the separate licensing actions of either power increase or plant life extension. The more difficult problem is to translate changes in component-specific margins to the plant as a whole, that is a more holistic assessment of plant safety or overall margin of safety. The compounding effects of multiple licensing actions should be included in such an integrated assessment. In this regard, the agency has recently initiated a research effort where interacting phenomena and potential synergies for multiple licensing actions are to be examined. Since Probabilistic Risk Assessment (PRA) methods provide a structure for an integrated approach to plant analysis, PRA techniques might well be adopted to examine the impact of margin reductions for individual components and separate actions, to the plant as a whole.

One of the more frustrating aspects of this examination has been the scarcity of information provided in licensee Uprate Safety Analysis Reports (SARs) with regards to the impact of the uprate on individual component performance and fragility, and for the plant as a whole. For example, although a re-examination of DBA-LOCA stress loads is stipulated for power updates under 10CFR50.92 requirements, the Hatch uprate SAR contained only a summary of predicted loads/stresses for a very limited number of components. Such predictions were generally presented in tabular form and provide solely information on the maximum stress for a few components. A schematic of the component and location of maximum stress, the time-development of the stress, and other signature information were generally lacking. Likewise, little information was provided as to boundary conditions and/or model assumptions employed in such calculations. The case study for the Hatch plant clearly demonstrates the need for considerably more information, if one desires a broad view of margin impact on the plant as whole. This author is lead to the conclusion that the paucity of information provided in recent uprate SARs and SERs is too limited in scope and depth, to provide an accurate picture of the full impact of the power increase on plant safety. A much clearer indication of margin impact was noted for the Hatch License Renewal Application (from CUF estimates), which largely stems from information requirements stipulated in the Standard Review Plan (SRP) for license renewal. It is thus concluded that development of similar type SRP for power uprates, would go a long way to remedy the critique of deficient information for uprate applications.

It is also noted that in the examination of margins for power updates in this report, it was assumed that design limits remain constant over the operational period of the uprate. This however may not be the case, as demonstrated by indications of crack welds in an access hole cover plate for the Hatch plant, and the associated reduction in plate design strength due to such flaws. Indeed one might expect some degree of degradation in various component design limits during the operation period at the uprated power level, owing to such factors as thermal and mechanical cycling-fatigue, material loss due to corrosion, stress assisted cracking, etc. Reductions in design limits were not accounted for here, but should be included as part of the recommended Uprate SRP.

It is finally noted that although the NRC has set upon a course of making greater use of risk information in the regulatory process, current regulatory reviews of license renewal applications and power uprates are largely being addressed from a deterministic approach and as separate/non-associated actions. Although uprate and renewal reviews include an evaluation of safety related components and systems to assure that current regulatory requirements are satisfied and that such equipment perform their intended function; uprate and renewal regulatory reviews are essentially done independently of one another. A consequence of this approach is that the lack of a *holistic or integrated* assessment of plant safety stemming from such multiple licensing actions. Clearly component margins to design limits are being consumed by the higher demands imposed by uprates and life extension for the same plant. Vessels are more embrittled at 60 years than at 40, while mechanical components are closer to their fatigue limits as the plant ages. Likewise, higher piping pressures and temperatures at increased power leave less margin to their design limits, while higher decay heat leaves less time for mitigative actions, and higher radionuclide inventories pose a potentially greater source term. With some development efforts, it is believed that PRA techniques could provide a more integrated assessment of risk owing to the combined influence of plant life extension and power increase.

The recent risk study for the 14.7-% power increase for the Swiss Leibstadt BWR plant serves as noteworthy example of how PRA methods yield insight into the risk for uprated conditions. Although the impact of margin reductions to design limits for individual components was not explicitly modeled in that study, the impact of higher decay heat and higher fission product inventories associated with the power increase were modeled. Results indicate only a small increases in CDF (core damage frequency) and LERF (large early release fraction) owing to the higher power level; however a 30-% increase in latent cancer and land contamination effects were indicated. This increase stems from the higher fission product inventory at the uprated power and the acceleration of events associated with a higher decay heat level. This study demonstrates that when metrics other than CDF are considered, there indeed appears to be risk impact owing to power uprates. It is from this perspective that the ACRS has recommended that NRC consider additional criteria to judge changes in risk for power uprates and license renewal. Regulatory judgements based principally on CDF and LERF may lead to a false sense of the safety significance of such licensing actions. Although the Hatch case study of component margin reductions to design limits for power uprates and plant life extension indicate a quite different metric of safety impact then CDF, latent cancers, or land contamination, the same trend-line is indicated. Extension of PRA techniques to incorporate the effects of component aging and margin reductions to design limits, would go a long way in clarifying the totality of safety implications for power uprates and plant life extension. This effort is recommended. In view of these observations, conclusions can be summarized as follows:

- Margin reductions to design limits of specific plant components were noted for the Hatch power uprates and license renewal. Since similar changes in component conditions can be expected for other plants involving similar licensing actions, one is drawn to the conclusion of *generic margin reductions* for power uprates and license renewal, although plant-to-plant variations would certainly exist.

- The Standard Review Plan for License Renewal and associated regulatory guidance define aging analysis (CUF analysis) requirements for passive components that must accompany such license applications; thus margin reductions to the CUF design limit of one are clearly evident in such submittals. At present, there is no corresponding regulatory requirements or review acceptance criteria for power uprates, and likewise no regulatory stipulations for indicators of component margin reductions to design limits. In the absence of uprate regulatory requirements, indicators of margin reductions to design limits are much less evident in uprate applications. In view of anticipated requests for significant power uprates (10-20 percent) to an ever-aging fleet of plants, this author is lead to the conclusion of a need for an Uprate Standard Review Plan and associated uprate submittal guidance, as is the case for license renewal. Uprate submittal guidance should include stipulations for indicators of margin reductions.

- One of the more frustrating aspects of this examination has been the paucity of information provided in licensee Uprate Safety Analysis Reports (SARs) and associated NRC Safety Evaluation Reports (SERs), with regards to the effect(s) of the power uprate on individual component performance and fragility, as well as for the plant as a whole.

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The case study for the Hatch plant clearly demonstrates the need for considerably more information, if one desires a broad view of margin impact on individual components and the plant. It is believed that the development of an Uprate Standard Review Plan (SRP) and associated regulatory guidance would go a long way in remedying this situation. The uprate SRP should include not only stipulations for margin impact, but also requirements for assurance of continued component conformance to their design limits at the expected life at uprated conditions.

- Margin estimates presented in this case study were for individual components and for separate license actions. No attempt was made to translate changes in component-specific margins to that for the plant as a whole, or to assess the compounding effects of multiple licensing actions. Such margin integration efforts are recommended. In this regard, the agency has recently initiated a research effort for FY2002-2003, where interacting phenomena and potential synergies for power uprates and license extension are to be examined. The need for such an examination is supported by conclusions drawn from the Hatch case study investigated in this report.

APPENDIX-A

Replacement of Access Cover Plates for Hatch Units 1 & 2

Note: This appendix is largely abstracted from a description of the Hatch plant access cover plate inspection and replacement efforts, which was provided by Mr. Robin Dyle, Southern Nuclear Operating Co., Birmingham, AL (Ref. A-1), and which is gratefully acknowledged. Neither Mr. Dyle nor Southern Nuclear Operating Co. are responsible for any miss-use or inaccuracies in this appendix. Figures were obtained from other sources (see Refs. A-2 and A-3).

A.1 Background

Figures A-1 and A-2 (see Ref. A-2) provide a schematic of typical GE-BWR reactor pressure vessel (RPV) designs, illustrating the think outer steel pressure vessel wall and an inner core shroud (either Inconel or steel clad in Inconel), with annular spacing between these structures. As indicted, the re-circulation jet pumps are contained within this spacing and supported by shroud support plate, also made of Inconel, which is welded to both the RPV and shroud walls. To allow access to the annular spacing between the RPV and shroud, two access holes are provided in the shroud support plate (see Figures A-2 and A-3, Ref. A-2), which are located approximately 180-degrees apart. These access holes are closed during normal operation by means of Inconel cover plates, which are either welded to (original design) or bolted to (replacement design) the shroud support plate. The access hole cover plates are only removed if maintenance or component replacement is required.

During a maintenance inspection of the Peach Bottom BWR-4 plant, cracks to the Inconel welding of the original access hole cover plate was noted using ultrasonic examination techniques. Following this discovery, General Electric (GE) issued a Service Information Letter, SIL-462, dated Feb.-1988, to alert owners of GE-BWR plants of this finding. NRC also issued an Information Notice to BWR owners, IN 88-03, of the Peach Bottom observations. During the following four years GE provided updates on industry inspection results and issued revisions and supplements to SIL-462 to inform BWR owners of the probable cause of cracking. The weld cracks were attributed to stress corrosion cracking (SCC) of the Inconel weld metal.

Subsequent ultrasonic examinations of the Hatch 1 & 2 access hole cover plates also indicated potential cracking at the welding material, which lead to licensee preemptive replacement of these cover plates during refueling outages in 1993 for Unit-1 and 1994 for Unit-2.

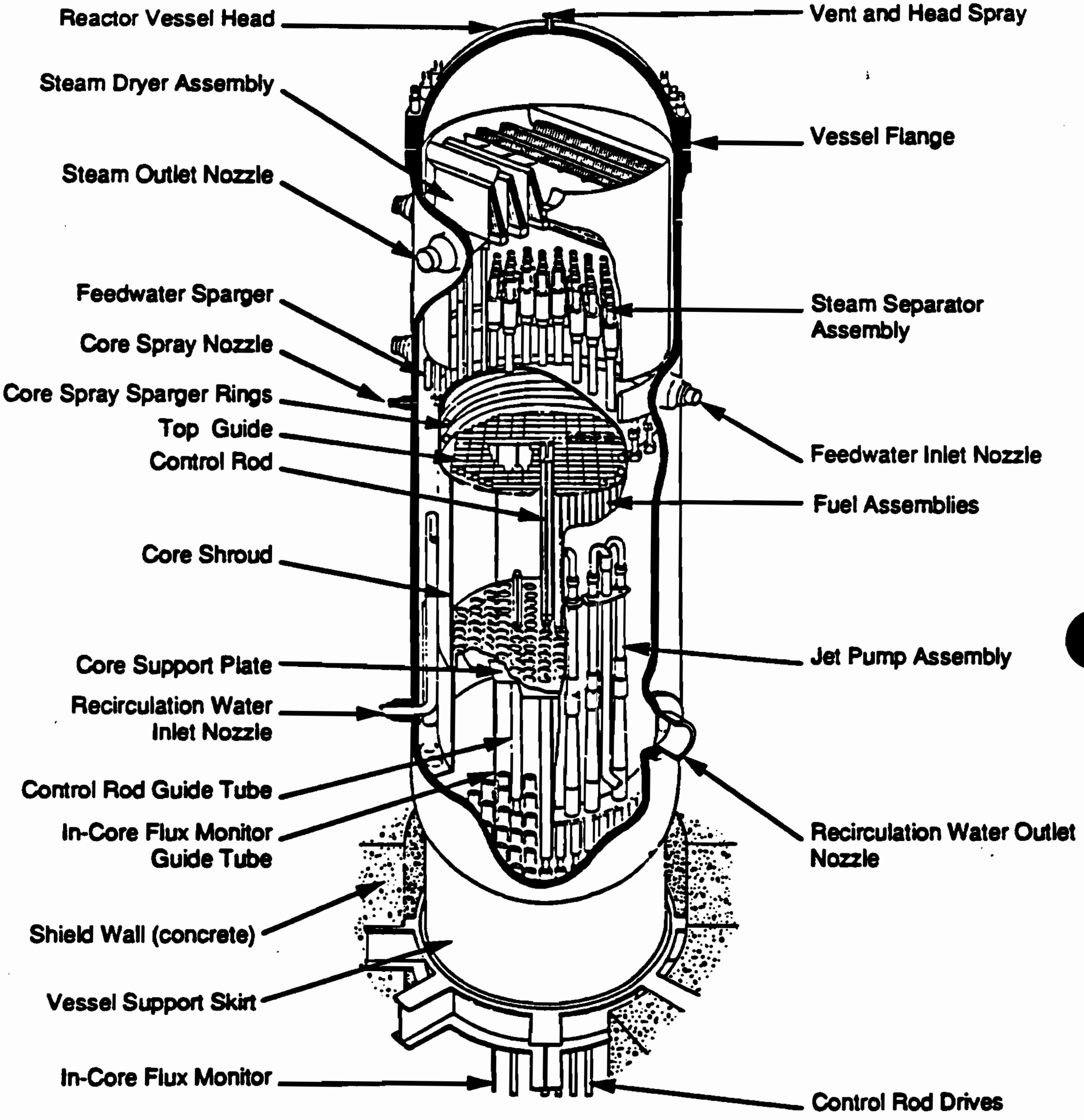

Figure A-1. Illustration of the reactor pressure vessel (RPV) and internals for typical GE-BWR type 3 and 4 plants. Note internal core shroud (Ref. A-2).

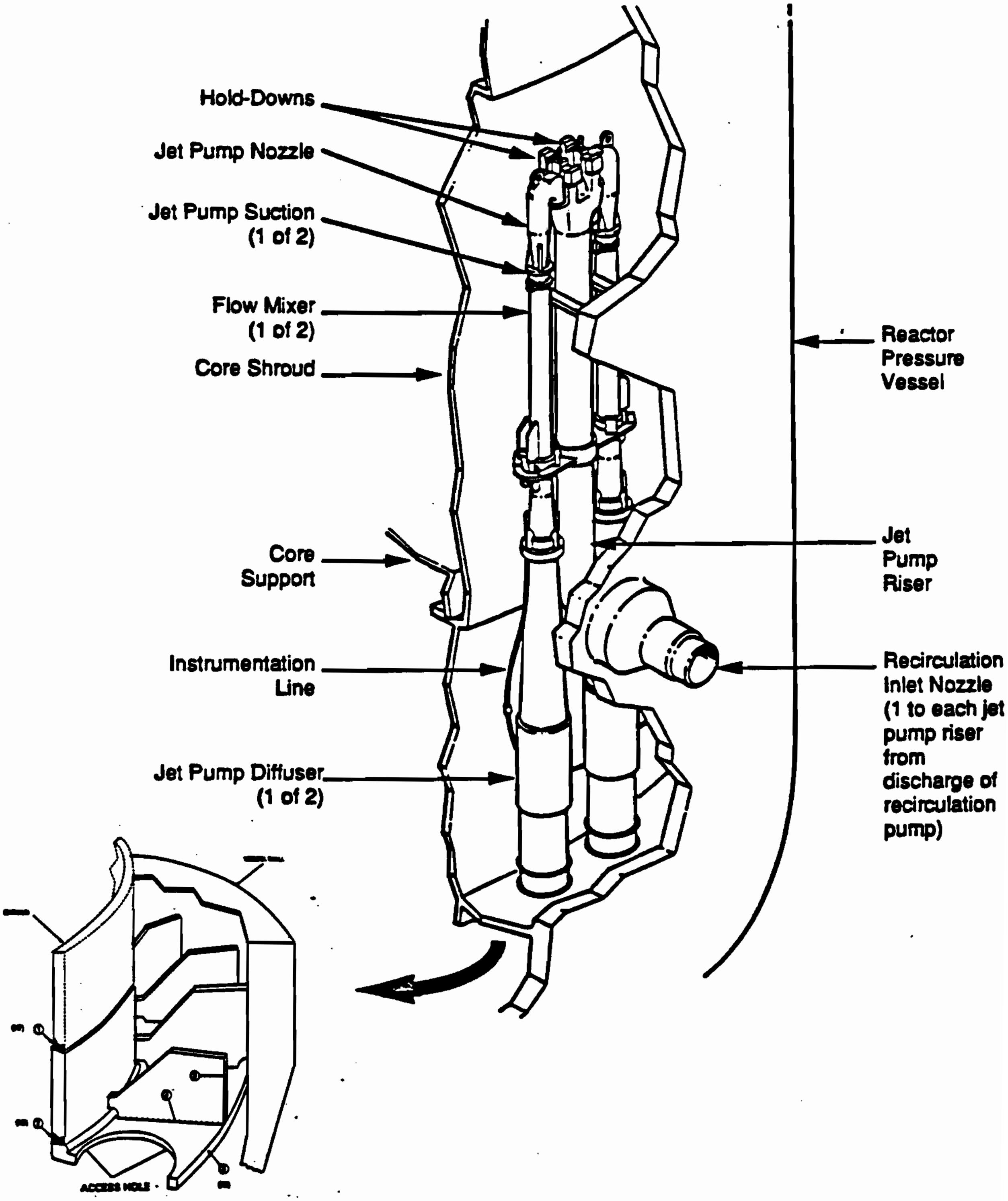

Figure A-2. Enlarged illustration of the reactor pressure vessel (RPV) and core shroud, in the region of the re-circulation jet pumps. Note shroud support plate which supports the re-circulation jet pump assembly and access hole in shroud support plate (Ref. A-2).

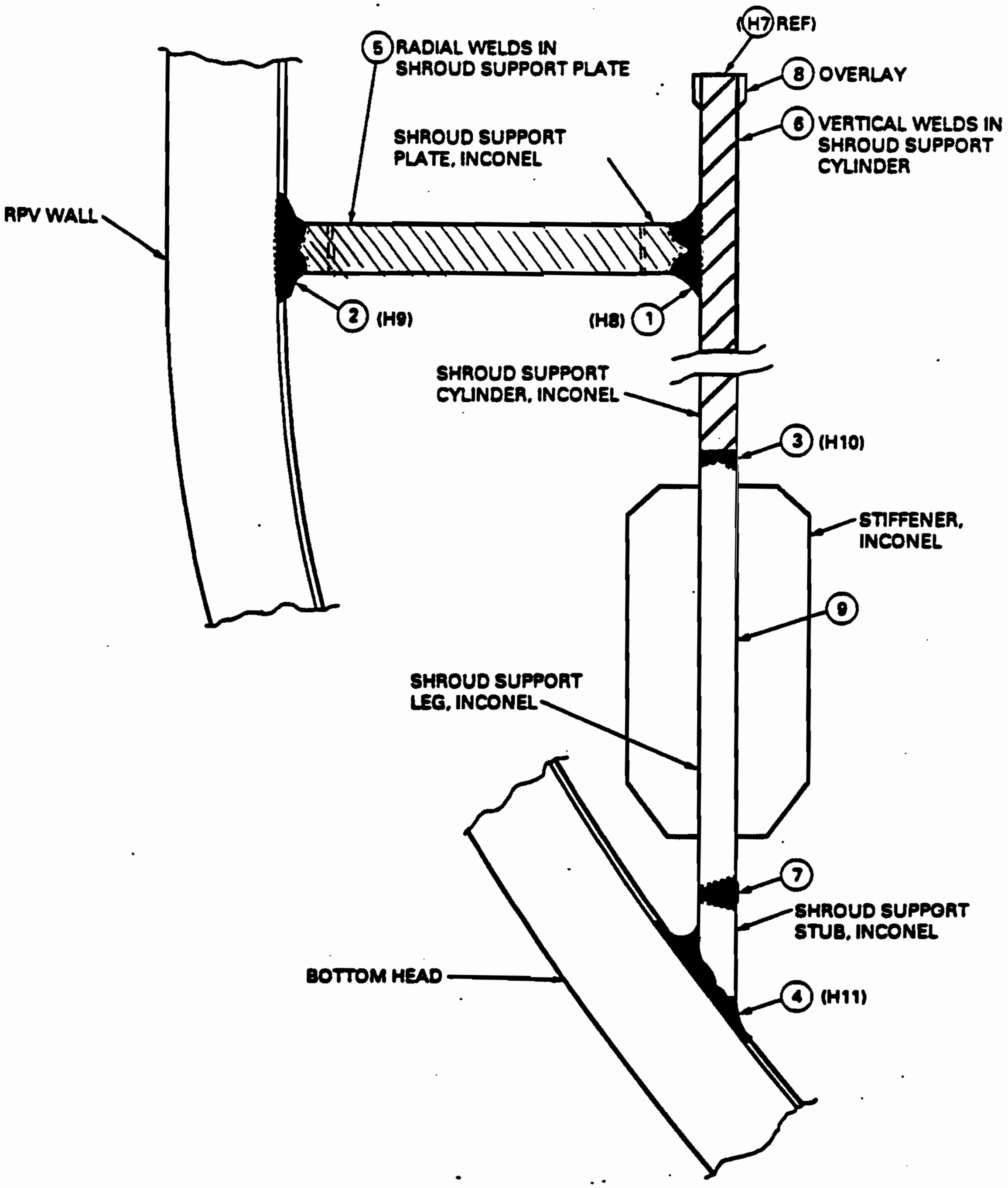

Figure A-3. Illustration of shroud support plate region and welding (Ref. A-2).

A-2. Hatch Access Cover Plate Inspections

Figure A-4 shows the basic features of the original Hatch-1 and Hatch-2 shroud support plate and access hole covers (AHC), which are somewhat different for these sister plants. Hatch-1 incorporated what is called the "thick" cover design, with a 2" thick Inconel-600 cover plate welded to a 2-1/2" thick Inconel-600 shroud support plate. Inspections were conducted during the Fall 1991 outage. Both cover plates in Unit-1 were inspected visually and one cover plate weld was inspected ultrasonically. The ultrasonic examinations were performed from the cover side and shroud support side of the weld. No crack indications were found at that time. Based on the subsequent recommendations regarding the potential for cracking described in GE SIL-462, the Unit 1 covers were scheduled for reinspection during the Spring 1993 outage. That inspection was not performed due to the subsequent preemptive repair discussed below.

Hatch-2 incorporated a unique access hole cover (AHC) design, the so-called "thin" cover design, with a 5/8" thick Inconel-600 cover welded to a 9" thick carbon steel shroud support plate clad with Inconel-182. The use of a steel shroud support plate clad with Inconel is unique to the Hatch-2 (see upper portion of Figure A-4). The Hatch-2 covers were initially inspected during the an outage in the spring of 1988, shortly after the Peach Bottom discovery. Both Hatch-2 covers were inspected visually and ultrasonically, with no crack indications at that time. The ultrasonic examinations in 1988 were performed from the cover side of the weld only.

Based on the subsequent recommendations in GE-SIL-462 (Supplement-3), the Hatch-2 covers were again inspected during another refueling/maintenance outage in the fall 1992. Visual and ultrasonic examinations were performed from both the cover side and shroud support side of the weld, with scans for both radial and circumferential indications. Circumferential crack indications were identified in Inconel-182 weld material at the 180° cover plate, with indications of up to 58-% through-wall cracking. Due to anomalies in the inspection data, it could not be confirmed that the indications were actually SCC-related. Georgia Power Company (GPC), the licensee at the time, elected to conservatively treat the indications as a SCC flaws and perform fracture mechanics evaluations, based on the assumption that the indications were indeed stress-corrosion cracks (SCCs). The evaluation concluded that sufficient margin was available to safely operate for an additional fuel cycle without additional corrective actions other than flow/power monitoring.

A meeting was held at the NRC on October 27, 1992 to discuss the examination observations. A physical description of the Hatch- 2 access hole cover design and its uniqueness among BWRs was given, the sequence of events for industry and Hatch responses to the indications of AHC weld cracking, inspection results for Hatch-2, a discussion of ultrasonic (UT) examination techniques, the extent of the Hatch-2 examination, location and characterization of the UT indications for Hatch-2, anomalies between this examination and other plants where cracking was observed, and results of fracture mechanics evaluations performed by GE. The consequences of a access cover failure were discussed, including the detachment of the cover plate and potential blockage of the re-circulation suction line. GPC concluded that there would be sufficient structural margin to operate for at least one more cycle without repair. GPC's plans were to operate for one more cycle, pursue alternative examination techniques to aid in flaw characterization, re-examine the Unit 2 covers in the following outage, and continue to pursue a long-term fix. The NRC advised that another operation cycle for Unit 2 was acceptable provided

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that: (a) GPC inspect the AHCs in both units every outage until the issue was resolved, (b) GPC recognize that restart of a Unit with through-wall cracks would not be approved in the future, (c) and that GPC inspect the AHCs as early as possible in subsequent outages.

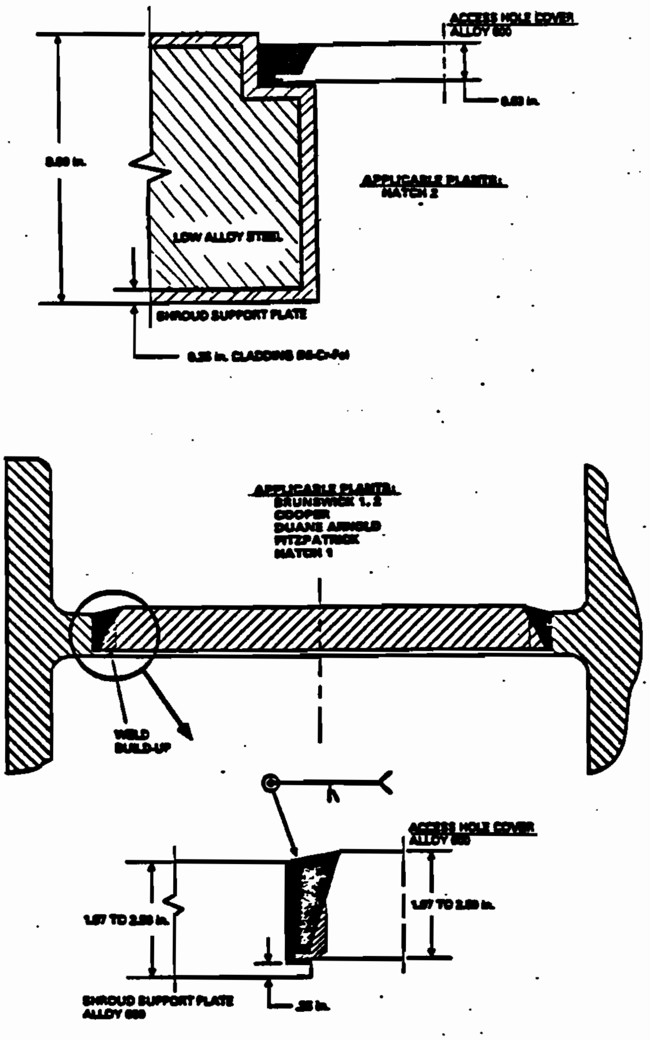

Figure A-4. Illustration of the original access hole cover plate design for the Hatch-1 and Hatch-2 (Ref. A-2).

Subsequent stress analyses for both Hatch Unit- 1 and Unit-2 access cover/support plate configurations were performed to evaluate the potential for radial and circumferential crack growth. For radial cracking it was found that it would take over 50 months (4.2 years) for an assumed 5/8" crack to grow to 2" on Unit-1. That same crack growth would require over 300 months (25 years) on Unit-2. The most critical location for a radial crack would be in either the ligament between the cover and the vessel wall or between the cover and the shroud wall. Analyses performed by GE in support of the generic evaluation indicated that the RPV could tolerate long through-wall flaws; therefore, significant structural margin would be available even in the unlikely event a radial crack propagated to the RPV wall. For circumferential cracking, Hatch Unit 1 and Unit 2 were determined to have essentially the same potential for crack initiation/growth and that a crack would grow at a rate of approximately 1inch per year circumferentially. Regarding the inspection results from Hatch Unit 2 in 1992, there were sufficient anomalies to cast doubt that the covers are actually cracked. These include:

a) There was no indication of surface cracking. This is contrary to all other reported cases of AHC cracking.

b) Indications observed from the shroud support side could not be verified from the cover side. In all other cases, verification from the cover side has been obtained.

c) The ultrasonic signal identified the interface between the Inconel clad and the carbon steel from the cover side of the weld. This would not have been possible if a crack existed.

d) There was no ultrasonic indication of cracking in the crevice area. This is where the crack should have originated from if the indication had been a true flaw.

e) Only one cover had indications. In all other reactor examinations, both covers on a given plant were cracked.

However, based on reported industry cracking experience and technical evaluations, the Hatch covers could still be susceptible to cracking at some juncture. If a pre-emptive repair was not performed, very costly inspections would be required at each outage, until a technical basis for extending the inspection interval could be developed. If repaired, only a visual exam of the bolting would be required as part of the normal in-vessel inspection program. Cost estimates indicated that temporary and permanent repairs involved similar expense. Considering these factors and the uncertainty of future situations, a pre-emptive replacement of access covers was determined to be the best course of action.

A-4. Hatch Cover Plate Replacement

A preemptive repair/replacement of the access cover for Hatch Unit 1 was made during a Spring outage in 1993, followed by a similar repair/replacement for Unit-2 the following year (spring 1994). The modifications employed materials resistant to inter-granular stress corrosion cracking. No welds were used (except for tack welds on the bolting retainers to prevent rotation) but rather bolting, thus eliminating welded crevices associated the stress corrosion cracking concern (SCC) for the prior cover welds. Due to the location of the access covers, irradiation levels are not significant and bolt relaxation is not a concern.

Post-modification inspections have been performed at least once on each new cover, with no evidence of cover degradation. Since installation of the new access covers, power uprates have been implemented for both Hatch units. In each case, the impact of the power increase on the AHC modification has been evaluated and shown to be within design margins. Finally, as a part of the Hatch 1 and 2 license renewal effort, the condition and adequacy of the AHC modifications are to be evaluated. It is expected that the modification are adequate for continued service during the current term and for the planned extended period of operation.

A-5. References:

1. Robin Dyle, *Plant Hatch Units 1 & 2 RPV Shroud Access Hole Cover Cracking and Repair*, Southern Nuclear Operating Co., Birmingham, AL, E-mail Memo, (April 17, 2001).

2. *Nuclear Power Plant System Source Book,* prepared by SAIC for the U. S. Nuclear Regulatory Commission, SAIC 89/103, (1989).

3. Electrical Power Research Institute, *BWR Vessel and Internals Project: Safety Assessment of BWR Reactor Internals (BWRVIP-06),* EPRI-TR-105707, (Oct. 1995).

ATTACHMENT 4

ATTACHMENT 5

To: Paul Boehnert, Senior Staff Engineer rm2E21 MS2E26

From: Larry Rossbach, Project Manager, PD3-2

Subject: **Dresden and Quad Cities Extended Power Uprate - 7 Additional Submittals**

Attached are seven additional submittals made by Exelon to support their extended power uprate (EPU) amendment request for Dresden, Units 2 and 3, and Quad Cities, Units 1 and 2. This information is to support the ACRS Thermal-Hydraulic Phenomena Subcommittee meeting on September 27 and 28 and the full ACRS meeting in October 2001. Please contact me (415-2863, Email lwr) if you have any questions.

Attached are:

1) 8/7/1 letter answering some plant systems questions.

2) 8/8/1 letter answering some mechanical engineering questions.

3) 8/13/1 letter answering the remaining mechanical engineering questions.

4) 8/13/1 letter answering additional plant systems questions.

5) 8/14/1 letter answering the remaining plant systems questions.

6) 8/14/1 letter answering some risk questions.

7) 8/29/1 submittal with revisions to the original EPU amendment request.

LWR:8/30/1

/

Exelon Nuclear

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10 CFR 50.90

RS-01-175

August 29, 2001

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Supplement to Request for License Amendment for Power Uprate Operation

References: (1) Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

(2) Letter from R. M. Krich (Exelon Generation Company, LLC) to U. S. NRC, "Supplement to Request for License Amendment for Power Uprate Operation," dated April 13, 2001

(3) Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 13, 2001

(4) Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for Technical Specifications Changes, Transition to General Electric Fuel," dated September 29, 2000

Pursuant to 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company (EGC), LLC, formerly Commonwealth Edison (ComEd) Company, is requesting additional changes to the Operating License (OL) and Technical Specifications (TS) relative to the changes proposed in References 1 and 2 for the Dresden Nuclear Power Station (DNPS), Units 2 and 3, and the Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2. These proposed changes include the following.

- A revision to the proposed credit for containment overpressure specified in the OL for DNPS, Unit 2.
- Deletion of the definition of maximum fraction of limiting power density (MFLPD) from TS Section 1.1, "Definitions," for DNPS, Units 2 and 3.
- Revision of the allowable value for the reactor vessel water level – low low function in TS Table 3.3.6.1-1, "Primary Containment Isolation Instrumentation," for DNPS, Units 2 and 3.
- Revision of the allowable value for the reactor vessel water level – low function in Table 3.3.6.2-1, "Secondary Containment Isolation Instrumentation," for DNPS, Units 2 and 3 and QCNPS, Units 1 and 2, and Table 3.3.7.1-1, "Control Room Emergency Ventilation (CREV) System Isolation Instrumentation," for QCNPS, Units 1 and 2.
- Revision of the allowable value for main steam flow – high in Table 3.3.7.1-1, "Control Room Emergency Ventilation (CREV) System Isolation Instrumentation," for QCNPS, Units 1 and 2.

In References 1 and 2, ComEd submitted various proposed OL and TS changes for DNPS and QCNPS to allow operation with an extended power uprate (EPU). One of the proposed changes was a revision to the proposed credit for containment overpressure specified in the OLs for DNPS, Units 2 and 3. In Reference 3, in response to NRC questions regarding this proposed change, EGC indicated that it would revise the proposed values for containment overpressure. This supplemental amendment request provides the revised proposed values for DNPS Unit 2. As discussed in Reference 3, revised proposed values for DNPS, Unit 3 and QCNPS, Units 1 and 2 will be provided in a future submittal.

In Reference 4, ComEd submitted various proposed TS changes to support a change in fuel vendors from Siemens Power Corporation, now Framatome, to General Electric (GE) Company, and a transition to GE14 fuel. One of the proposed changes was to include the definition of MFLPD in the DNPS TS. However, once the EPU proposed changes are approved, the use of limits related to MFLPD is no longer required. Since the GE14 proposed changes will be approved before approval of the EPU proposed changes, this supplemental amendment request proposes deletion of the definition of MFLPD from the TS for DNPS, Units 2 and 3.

During review of instrumentation setpoints for the EPU project, it was determined that the allowable value for the main steam line isolation on reactor vessel water level – low low was based on an assumed instrument temperature range that was inconsistent with the assumed temperature ranges for instruments in the same loop. The EPU analyses did not change the temperature range for this instrument or the analytical limit for the low low water level function. However, to correct this inconsistency in the assumed temperature range, a change is proposed in the allowable value for this function.

The EPU proposed changes identified the allowable value changes in TS Tables 3.3.1.1-1, "Reactor Protection System Instrumentation," and 3.3.6.1-1, "Primary Containment Isolation Instrumentation." During implementation reviews for the EPU, it was recognized that the same allowable value changes are required in Table 3.3.6.2-1, "Secondary Containment Isolation Instrumentation," for DNPS and QCNPS, and Table 3.3.7.1-1, "Control Room Emergency Ventilation (CREV) System Isolation

Instrumentation," for QCNPS. Upon discovery of this oversight, EGC initiated a corrective action program condition report (CR) to determine the cause and corrective actions for the oversight. We have determined that, while the EPU technical reviews were thorough, there was an inadequate focus on assuring completeness of the TS changes. Subsequently, we have completed additional reviews of the TS and we have not identified any additional changes needed to support the EPU amendment request beyond those described in this supplemental request.

EGC has determined that with the exception of the main steam line isolation function that occurs on reactor vessel water level – low, low (DNPS only), the information contained in this letter does not affect the information provided in Reference 1 supporting a finding of no significant hazards consideration.

This supplement to the Reference 1 and 2 amendment requests contains separate enclosures for DNPS and QCNPS. Each enclosure is subdivided as follows.

1. Attachment A contains a detailed description of the additional proposed changes.
2. Attachment B provides the proposed mark-ups to the TS and OL (DNPS Unit 2 only) for the proposed changes.
3. Attachment C provides a supplement to the information supporting a finding of no significant hazards consideration for the proposed changes in accordance with 10 CFR 50.92(c), "Issuance of Amendment," for DNPS only.
4. Attachment D provides information supporting an Environmental Assessment for DNPS only.

The proposed changes have been reviewed by the Plant Operations Review Committees and approved by the Nuclear Safety Review Boards at DNPS and QCNPS in accordance with the Quality Assurance Program.

EGC is notifying the State of Illinois of this license amendment request by transmitting a copy of this letter and its attachments to the designated State Official.

EGC requests that these additional changes be reviewed and approved as part of the proposed changes for power uprate operation previously submitted in References 1 and 2.

Should you have any questions related to this request, please contact Mr. Allan R. Haeger at (630) 657-2807.

Respectfully,

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Attachments:

Affidavit
Enclosure 1: Dresden Nuclear Power Station
Attachment A: Description and Summary Safety Analysis for Proposed Changes
Attachment B: Marked-Up TS and OL Pages for Proposed Changes
Attachment C: Information Supporting a Finding of No Significant Hazards Consideration
Attachment D Information Supporting an Environmental Assessment

Enclosure 2: Quad Cities Nuclear Power Station
Attachment A: Description and Summary Safety Analysis for Proposed Changes
Attachment B: Marked-Up TS Pages for Proposed Changes

cc: Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station
NRC Senior Resident Inspector – Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

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bcc Dresden Project Manager - NRR
Quad Cities Project Manager - NRR
Manager of Energy Practice - Winston & Strawn
Director – Licensing, Mid-West Regional Operating Group
Manager – Licensing, Dresden and Quad Cities Station
Site Vice President – Dresden Station
Site Vice President – Quad Cities Station
Regulatory Assurance Manager – Dresden Station
Regulatory Assurance Manager – Quad Cities Station
D. Tubbs – MidAmerican Energy Company
W. Leech – MidAmerican Energy Company
Document Control Desk Licensing (Hard Copy)
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STATE OF ILLINOIS)

COUNTY OF DUPAGE)

IN THE MATTER OF:)

EXELON GENERATION COMPANY, LLC) **Docket Numbers**

DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3) **50-237 and 50-249**
QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2) **50-254 and 50-265**

SUBJECT: Supplement to Request for License Amendment for Power Uprate Operation

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Subscribed and sworn to before me, a Notary Public in and

for the State above named, this 29th day of

August, 2001

" OFFICIAL SEAL "
Timothy A. Byam
Notary Public, State of Illinois
My Commission Expires 11/24/2001

Notary Public

ENCLOSURE 1 - ATTACHMENT A

Supplement to Request For Power Uprate Operation
Dresden Nuclear Power Station, Units 2 and 3

DESCRIPTION AND SUMMARY SAFETY ANALYSIS FOR PROPOSED CHANGES

A. SUMMARY OF PROPOSED CHANGES

Pursuant to 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company (EGC), LLC, formerly Commonwealth Edison (ComEd) Company, is requesting additional changes to the Technical Specifications (TS) relative to the changes proposed in References I.1 and I.2 for the Dresden Nuclear Power Station (DNPS), Units 2 and 3 and Operating License (OL) for DNPS, Unit 2. These proposed changes include the following.

- A revision to the proposed credit for containment overpressure specified in the OL for DNPS, Unit 2.
- Deletion of the definition of maximum fraction of limiting power density (MFLPD) from TS Section 1.1, "Definitions," for DNPS, Units 2 and 3.
- Revision of the allowable value for the main steam line isolation reactor vessel water level – low low function in TS Table 3.3.6.1-1, "Primary Containment Isolation Instrumentation," for DNPS, Units 2 and 3.
- Revision of the allowable value for the reactor vessel water level – low function in Table 3.3.6.2-1, "Secondary Containment Isolation Instrumentation," for DNPS, Units 2 and 3.

In References I.1 and I.2, ComEd submitted various proposed OL and TS changes for DNPS to allow operation with an extended power uprate (EPU). One of the proposed changes was a revision to the proposed credit for containment overpressure specified in the OLs for DNPS, Units 2 and 3. In Reference I.3, in response to NRC questions regarding this proposed change, EGC indicated that it would revise the proposed value for containment overpressure. This supplement to our amendment request provides the revised proposed values for DNPS, Unit 2. As discussed in Reference I.3, revised proposed values for DNPS, Unit 3 will be provided in a future submittal.

In Reference I.4, ComEd submitted various proposed TS changes to support a change in fuel vendors from Siemens Power Corporation, now Framatome, to General Electric (GE) Company, and a transition to GE14 fuel. One of the proposed changes was to include the definition of MFLPD in the DNPS TS. However, once the EPU proposed changes are approved, limits related to MFLPD are no longer required. Since the GE14 proposed changes will be approved before approval of the EPU proposed changes, this supplement to our amendment request proposes deletion of the definition of MFLPD from the TS for DNPS, Units 2 and 3.

During review of instrumentation setpoints for the EPU project, it was determined that the allowable value for the main steam line isolation on reactor vessel water level – low low was based on an assumed instrument temperature range that was inconsistent with other assumed temperature ranges for instruments in the same loop. The EPU analyses

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did not change the temperature range for this instrument or the analytical limit for the low low water level function. However, to correct this inconsistency in the assumed temperature range, a change is proposed in the allowable value for this function.

Reference I.1 proposed changes to allowable values in TS Tables 3.3.1.1-1, "Reactor Protection System Instrumentation," and 3.3.6.1-1, "Primary Containment Isolation Instrumentation." During implementation reviews for the EPU, it was recognized that the same allowable value change is required in Table 3.3.6.2-1, "Secondary Containment Isolation Instrumentation."

B. DESCRIPTION OF THE CURRENT REQUIREMENTS

B.1 OL Condition on Containment Overpressure

DNPS, Unit 2 has an OL condition associated with TS Amendment 157 that states the following.

> "The license is amended to authorize changing the UFSAR to allow credit for containment overpressure as detailed below, to assure adequate Net Positive Suction Head is available for low pressure Emergency Core Cooling System pumps following a design basis accident."

Time (seconds)	Containment Pressure (PSIG)
0-240	9.5
240-480	2.9
480-6000	1.9
6000-accident end	2.5

B.2 TS Section 1.1, "Definitions"

In the Reference I.4 amendment request, ComEd proposed to add the definition of MFLPD to the TS.

B.3 TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

Table 3.3.6.1-1, "Primary Containment Isolation Instrumentation," Function 1.a, identifies the allowable value for the main steam line isolation that occurs on reactor vessel water level – low low. The allowable value is ≥ -56.77 inches.

B.4 TS Section 3.3.6.2, "Secondary Containment Isolation Instrumentation"

Table 3.3.6.2-1, "Secondary Containment Isolation Instrumentation," Function 1, identifies the allowable value for the reactor vessel water level – low function. The allowable value is ≥ 10.24 inches.

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C. BASES FOR THE CURRENT REQUIREMENTS

C.1 OL Condition on Containment Overpressure

To ensure that there is adequate net positive suction head (NPSH) to support the operation of the emergency core cooling system (ECCS) pumps during design basis accident (DBA) conditions, the analyses take credit for containment overpressure. This allowance was approved in TS Amendment 157 for DNPS Unit 2 (Reference I.5).

C.2 TS Section 1.1, "Definitions"

The definition of MFLPD is included in the Reference I.4 amendment request to support the use of reactor thermal limits using this GE parameter.

C.3 TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

The function of the primary containment isolation on low-low reactor vessel water level is to limit fission product release during and following postulated DBAs.

C.4 TS Section 3.3.6.2, "Secondary Containment Isolation Instrumentation"

A low reactor vessel water level indicates that the capability to cool the fuel may be threatened. Should the reactor vessel water level decrease too far, fuel damage could result. An isolation of the secondary containment and actuation of the standby gas treatment system are initiated in order to minimize the potential of an offsite release.

D. NEED FOR REVISION OF THE REQUIREMENTS

D.1 OL Condition on Containment Overpressure

The analysis associated with the postulated LOCA at increased power levels results in an increase in suppression pool water temperature. Because of the increase in water temperature, the need for additional credit for containment overpressure to maintain adequate NPSH for the ECCS pumps has been identified.

D.2 TS Section 1.1, "Definitions"

One of the proposed changes in the Reference I.4 amendment request for GE14 fuel was to include the definition of MFLPD in the DNPS TS. The Reference I.1 amendment request for EPU proposed to delete the thermal limits related to MFLPD and substitute power and flow dependent limits known as the Average Power Range Monitor (APRM) Rod Block Monitor (RBM) TS changes (i.e., ARTS changes). Therefore, once the EPU proposed changes are approved, the use of limits related to MFLPD is no longer required. Since the GE14 proposed changes will be approved before approval of the EPU proposed changes, this supplement to our amendment request proposes deletion of the definition of MFLPD from the TS for DNPS, Units 2 and 3.

D.3 TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

During a review of instrumentation setpoints for the EPU project, it was determined that the allowable value for the main steam line isolation on reactor vessel water level – low low was based on an assumed instrument temperature range that was inconsistent with other assumed temperature ranges for instruments in the same loop. The EPU analyses did not change the temperature range for this instrument or the analytical limit for the low low reactor vessel water level function. However, to correct this inconsistency in the assumed temperature range, a change is proposed in the allowable value for this function.

D.4 TS Section 3.3.6.2, "Secondary Containment Isolation Instrumentation"

The loss of feedwater transient was reanalyzed under EPU conditions. Due to increased core heat generation as a result of EPU, the reactor pressure vessel (RPV) water level decreases more rapidly in this transient. Therefore, the Reference I.1 amendment request proposed to lower the reactor vessel low water level scram setpoint in order to increase the potential for recovery before reaching the scram setpoint and thus prevent unnecessary challenges to safety systems and provide additional time for operator action.

The proposed change to the allowable value for the secondary containment isolation function on reactor vessel water level – low is directly related to the proposed change for the reactor scram setpoint reduction. To maintain the secondary containment isolation function at the same level as the reactor scram, the allowable value for TS Table 3.3.6.2-1, Function 1, must also be revised.

E. DESCRIPTION OF THE PROPOSED CHANGES

E.1 OL Condition on Containment Overpressure

The allowance for containment overpressure in the DNPS, Unit 2 OL condition is revised to state the following.

> "The license is amended to authorize changing the UFSAR to allow credit for containment overpressure as detailed below, to assure adequate Net Positive Suction Head is available for low pressure Emergency Core Cooling System pumps following a design basis accident."

Period	Requested Credit (psi)
0 – 290 sec	9.5
290 - 5,000 sec	4.8
5,000 – 30,000 sec	6.6
30,000 - 40,000 sec	6.0
40,000 - 45,500 sec	5.4
45,500 - 52,500 sec	4.9
52,500 - 60,500 sec	4.4
60,500 - 70,000 sec	3.8

//

70,000 - 84,000 sec	3.2
84,000 - 104,000 sec	2.5
104,000 - 136,000 sec	1.8
136,000 sec – accident end	1.1

E.2 TS Section 1.1, "Definitions"

The definition of MFLPD is deleted.

E.3 TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

The allowable value for TS Table 3.3.6.1-1, Function 1.a, is revised from ≥ -56.77 inches to ≥ -56.34 inches.

E.4 TS Section 3.3.6.2, "Secondary Containment Isolation Instrumentation"

The allowable value for Table 3.3.6.2-1, Function 1, is revised from ≥ 10.24 inches to ≥ 2.65 inches.

F. SUMMARY SAFETY ANALYSIS OF THE PROPOSED CHANGES

F.1 OL Condition on Containment Overpressure

Additional credit for containment overpressure is required because the suppression pool temperature increases at a faster rate and peaks at a higher value compared to the pre-EPU conditions during a loss of coolant accident (LOCA). Because vapor pressure increases as the suppression pool temperature increases, the net positive suction head available (NPSHa) for each ECCS pump is reduced. To offset this reduction in NPSHa, more overpressure credit is required. More overpressure is also available, since the containment and suppression pool pressures also increase at a faster rate and peak at a higher value than before EPU.

Containment Response
The design basis accident (DBA) LOCA containment response for NPSH evaluations is analyzed for two time periods: short term (i.e., before 600 seconds), and long term (i.e., after 600 seconds). The long term temperature and pressure conditions of the suppression pool are determined based on assumptions that maximize the pool temperature and minimize the overpressure, including operation of containment sprays and vacuum breakers. Specific assumptions include the following.

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

2. The reactor is operating at 102% of EPU (i.e., 3016 megawatts-thermal (MWt)) with an initial reactor pressure of 1005 pounds per square inch - gauge (psig). Concurrent with occurrence of the break, reactor scram occurs.

3. The reactor core power includes fission energy, fuel stored energy, metal-water reaction energy and decay heat calculated in accordance with American Nuclear Society (ANS) Standard 5.1-1979, "Decay Heat Source Term for Containment Long-Term Pressure and Temperature Analysis," for a 24 month fuel cycle with two sigma adder.

4. The initial suppression pool water volume corresponds to the low water level to maximize the suppression pool temperature response.

5. Containment cooling is achieved by operating one low pressure coolant injection (LPCI)/ containment cooling loop at 600 seconds in the containment spray mode, with drywell and wetwell sprays. This minimizes the containment pressure response, since cold water sprays will bring down the pressure.

The short term conditions are based on similar assumptions, with the following exceptions.

1. There is a single failure of the loop selection logic. Consequently, the flow from all four LPCI pumps goes into the broken recirculation loop and subsequently discharges into the drywell directly. The maximum runout flow rate is assumed.

2. Both core spray pumps are operating with the maximum flow rate.

Procedures

Existing plant emergency operating procedures include cautions concerning exceeding ECCS pump NPSH limits. The procedures also contain ECCS pump curves of pump flow versus torus pressure and temperature conditions. The same cautions and NPSH curves are included in the emergency operating procedures that control use of containment sprays. Thus, the operators have sufficient procedural direction to control both ECCS pump flow and containment pressure within limits.

Methodology and Results for DNPS

That the proposed overpressure credit is based on the methodology previously approved for DNPS in a 1997 license amendment regarding containment overpressure (Reference I.5). This methodology followed the original design basis of one ECCS suction strainer completely blocked, with the remaining three strainers in a clean condition. The head loss across the three clean strainers was assumed to be the same as the head loss for the original suction strainers, although those strainers were subsequently replaced with higher capacity strainers. Thus, the assumed head loss is slightly higher than the actual head loss expected with the new strainers. This assumption maintains consistency with the basis for approval of the Reference I.5 amendment request. We also expect that the head loss used to develop the requested overpressure will result in adequate overpressure when compared to the results of future calculations of suction strainer head loss discussed in the paragraph below.

NRC Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors," requested that licensees calculate suction strainer head loss assuming that debris from the primary containment is distributed across all of

the ECCS suction strainers. In accordance with this request, we will perform calculations of the suction strainer head loss and will submit a description of the calculational methods and the results to the NRC.

NPSH calculations have been performed for EPU conditions with the strainer head loss assumptions described above for two short term and two long term flow conditions. The limiting short term ECCS flow case is all four LPCI pumps and both core spray pumps operating at maximum flow conditions. The limiting long term ECCS flow rate is the same as in the 1997 calculations that formed the basis of the currently approved overpressure credit. This limiting flow rate is 19,000 gallons per minute (gpm) distributed as follows: two core spray pumps operating at 4,500 gpm each, one LPCI pump at 5,000 gpm, and two additional LPCI pumps at 2,500 gpm each. This flow case is significantly more than the minimum long term flow of 9,750 gpm required to maintain adequate core and containment cooling after EPU. The minimum flow case, one core spray pump operating at 4,750 gpm and one LPCI pump operating at 5,000 gpm, is the other case analyzed in the calculations.

The graphs showing the results of the ECCS NPSH calculations for the limiting short term and long term flow cases are provided in Figures 1 and 2. Core spray flow is the limiting NPSH case in the short term, and LPCI flow is limiting for NPSH in the long term. Figures 1 and 2 also show NPSH required (NPSHr) for both the old strainer and new strainer cases (e.g., one blocked, three clean). The higher head loss of the old strainers, as indicated above, is the basis for the requested overpressure.

In the short term, there is a period from approximately 290 seconds to 600 seconds during which some ECCS pump cavitation may occur, since the available NPSH is less than the required NPSH. This period is after the time at which the peak cladding temperature (PCT) has been reached at approximately 240 seconds. Prior to 290 seconds, the requested overpressure ensures that adequate NPSH is available to meet the core cooling requirements assumed in the PCT calculations. After 600 seconds, ECCS pump throttling restores adequate NPSH. Pump cavitation for the brief time from 290 seconds to 600 seconds is not of concern due to the short duration of the cavitation, as discussed in Reference I.5.

The long term overpressure curves are plotted out to 200,000 seconds. From this point, NPSHa and NPSHr both vary directly as a function of the vapor pressure. The result is that both decrease in parallel fashion, maintaining a margin between available and required NPSH.

F.2 TS Section 1.1, "Definitions"

The Reference I.1 amendment request describes the safety analysis for removing the MFLPD limit from the TS. With the approval of the Reference I.1 proposed changes, the removal of the definition of MFLPD is an administrative change, since no other TS items make use of this definition.

F.3 TS Section 3.3.6.1, "Primary Containment Isolation Instrumentation"

The allowable value proposed does not represent a change in the analytical limit assumed in the safety analysis for the low-low reactor vessel water level. The allowable value was recalculated following the review of instrumentation setpoints described in Section D.3 above, using a wider and thus more conservative temperature range for the low-low reactor vessel water level instrumentation. This allowable value was calculated in accordance with the Exelon Nuclear Mid-West Regional Operating Group setpoint methodology procedure NES-EIC-20.04, "Analysis of Instrument Channel Setpoint Error and Instrument Loop Accuracy," Revision 3.

The current allowable values for other functions in the TS related to reactor vessel water level low and low-low have been determined using the appropriate temperature ranges and require no adjustment.

F.4 TS Section 3.3.6.2, "Secondary Containment Isolation Instrumentation"

The reactor vessel water level - low function is assumed in the analysis of the recirculation line break and is credited in the loss of normal feedwater flow event. The reactor scram associated with the function reduces the amount of energy required to be absorbed and, along with the actions of the emergency core cooling systems, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors." The associated secondary containment isolation function is initiated in order to minimize the potential of an offsite release. The allowable value for the secondary containment isolation function is chosen to be the same as the allowable value for the reactor protection system setpoint and is not analyzed separately. The proposed change in the reactor scram setpoint does not result in a change to the current safety analyses. Thus, the change in the allowable value for the secondary containment isolation function continues to ensure that any offsite releases are within the limits calculated in the safety analysis.

G. IMPACT ON PREVIOUS SUBMITTALS

All submittals currently under review by the NRC were evaluated to determine the impact of these proposed changes. These proposed changes supplement the changes proposed to support uprated power operation at DNPS in Reference I.1.

In addition, these proposed changes affect the proposed changes submitted in Reference I.6, which requested that the NRC consider the proposed changes to the reactor vessel water level – low setpoint separately from the EPU amendment request. The additional proposed change being submitted in this amendment request is also being submitted to the NRC separately as a supplement to the Reference I.6 amendment request.

No other submittals currently under review by the NRC are affected by the information presented in this supplement to our Reference I.1 license amendment request.

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H. SCHEDULE REQUIREMENTS

We request that these proposed changes be reviewed and approved as part of the proposed changes for power uprate operation previously submitted in References I.1 and I.2.

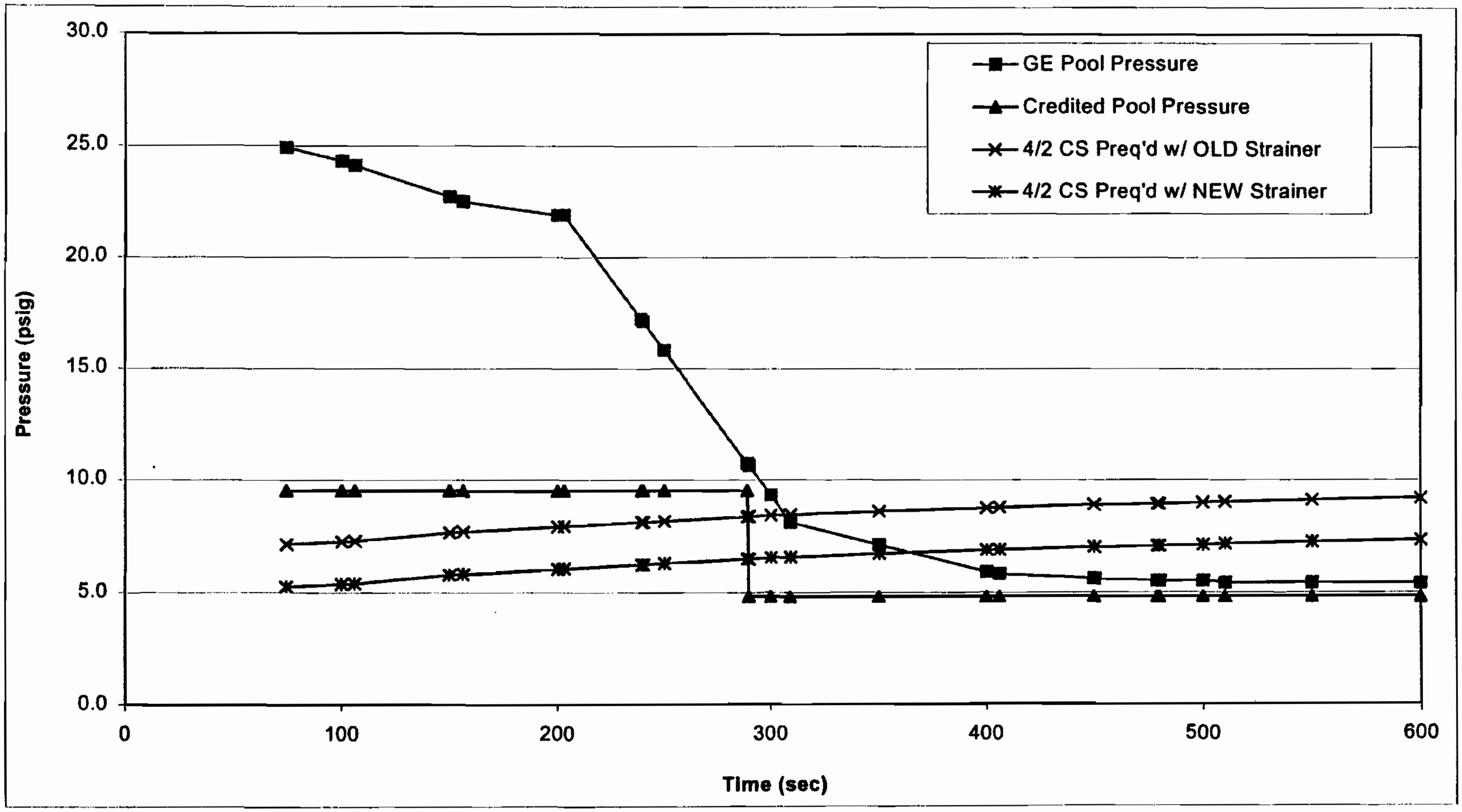
I. REFERENCES

1. Letter from R. M. Krich (ComEd) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000
2. Letter from R. M. Krich (EGC) to U. S. NRC, "Supplement to Request for License Amendment for Power Uprate Operation," dated April 13, 2001
3. Letter from K. A. Ainger (EGC, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 13, 2001
4. Letter from R.M. Krich (ComEd) to U. S. NRC, "Request for Technical Specifications Changes, Transition to General Electric Fuel," dated September 29, 2000
5. Letter from U. S. NRC to I. Johnson (ComEd), "Issuance of Amendments," dated April 30, 1997
6. Letter from R. M. Krich (EGC) to U. S. NRC, "Request for License Amendment for Reactor Vessel Low Water Level Setpoint," dated February 22, 2001

ENCLOSURE 1 - ATTACHMENT A

Supplement to Request For Power Uprate Operation
Dresden Nuclear Power Station, Units 2 and 3

Figure 1
Short Term NPSH Curves



ENCLOSURE 1 - ATTACHMENT A

Supplement to Request For Power Uprate Operation
Dresden Nuclear Power Station, Units 2 and 3

Figure 2
Long Term NPSH Curves

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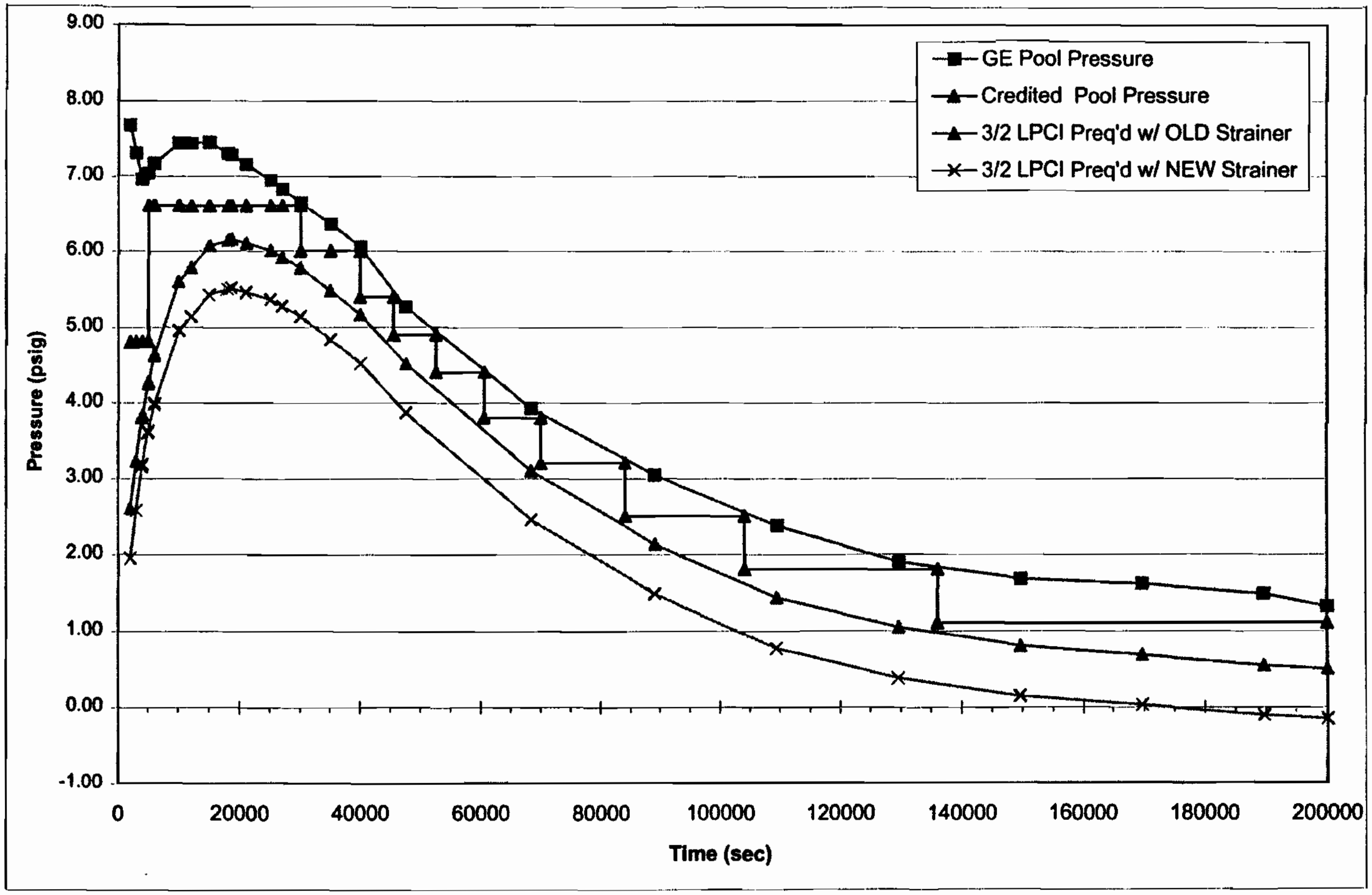

ENCLOSURE 1 - ATTACHMENT B
Supplement to Request For Power Uprate Operation
Dresden Nuclear Power Station, Units 2 and 3

MARKED-UP OPERATING LICENSE PAGE FOR PROPOSED CHANGES

<u>REVISED PAGE</u>
Appendix B, Page 1 (DPR-19)

MARKED-UP TS PAGES FOR PROPOSED CHANGES

<u>REVISED PAGES</u>
1.1-4
3.3.6.1-5
3.3.6.2-4

ENCLOSURE 1 - ATTACHMENT B

Supplement to Request For Power Uprate Operation
Dresden Nuclear Power Station, Units 2 and 3

MARKED-UP OPERATING LICENSE PAGE FOR PROPOSED CHANGES

REVISED PAGE
Appendix B, Page 1 (DPR-19)

MARKED-UP TS PAGES FOR PROPOSED CHANGES

REVISED PAGES
1.1-4
3.3.6.1-5
3.3.6.2-4

APPENDIX B

ADDITIONAL CONDITIONS

FACILITY OPERATING LICENSE NO. DPR-19

The licensee shall comply with the following conditions on the schedules noted below:

Amendment Number	Additional Condition	Implementation Date
157	The license is amended to authorize changing the UFSAR to allow credit for containment overpressure as detailed below, to assure adequate Net Positive Suction Head is available for low pressure Emergency Core Cooling System pumps following a design basis accident.	Effective as of the issuance of Amendment No. ~~157~~ and shall be implemented within 30 days.

~~Time (seconds)~~	~~Containment Pressure (PSIG)~~
~~0-240~~	~~9.5~~
~~240-480~~	~~2.9~~
~~480-6000~~	~~1.9~~
~~6000-accident end~~	~~2.5~~

Replace with Insert

Amendment Number	Additional Condition	Implementation Date
157	The EOPs shall be changed to alert operator to NPSH concerns and to make containment spray operation consistent with the overpressure requirements for NPSH.	Shall be implemented within 30 days after issuance of Amendment No. 157.
160	This amendment authorizes the licensee to incorporate in the Updated Final Safety Analysis Report (UFSAR), the description of the Reactor Coolant System design pressure, temperature and volume that was removed from Technical Specification Section 5.4, and evaluated in a safety evaluation dated June 12, 1997.	30 days from the date of issuance of Amendment No. 160.
163	The licensee shall review the Dresden Operation Annunciator and General Abnormal Conditions Procedures and revise them as required to ensure operator action is taken in a timely manner to limit occupational doses and environmental releases.	60 days from the date of issuance of Amendment No. 163

INSERT TO APPENDIX B (DPR-19)

Period	Requested Credit (psi)
0 – 290 sec	9.5
290 - 5,000 sec	4.8
5,000 – 30,000 sec	6.6
30,000 - 40,000 sec	6.0
40,000 - 45,500 sec	5.4
45,500 - 52,500 sec	4.9
52,500 - 60,500 sec	4.4
60,500 - 70,000 sec	3.8
70,000 - 84,000 sec	3.2
84,000 - 104,000 sec	2.5
104,000 - 136,000 sec	1.8
136,000 sec – accident end	1.1

1.1 Definitions (continued)

LINEAR HEAT GENERATION RATE (LHGR)	The LHGR shall be the heat generation rate per unit length of fuel rod. It is the integral of the heat flux over the heat transfer area associated with the unit length.
LOGIC SYSTEM FUNCTIONAL TEST	A LOGIC SYSTEM FUNCTIONAL TEST shall be a test of all required logic components (i.e., all required relays and contacts, trip units, solid state logic elements, etc.) of a logic circuit, from as close to the sensor as practicable up to, but not including, the actuated device, to verify OPERABILITY. The LOGIC SYSTEM FUNCTIONAL TEST may be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.
~~MAXIMUM FRACTION OF LIMITING POWER DENSITY (MFLPD)~~	~~The MFLPD shall be the largest value of the fraction of limiting power density (FLPD) in the core. The FLPD shall be the LHGR existing at a given location divided by the specified LHGR limit for that bundle type.~~
MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE – OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that

(continued)

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Table 3.3.6.1-1 (page 1 of 3)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	-56.34 ≥ ~~-56.77~~ inches
b. Main Steam Line Pressure – Low	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≥ 831 psig
c. Main Steam Line Pressure – Timer	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 0.280 seconds (Unit 2) ≤ 0.236 seconds (Unit 3)
d. Main Steam Line Flow – High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≤ 160.5 psid (Unit 2) ≤ 117.1 psid (Unit 3)
e. Main Steam Line Tunnel Temperature – High	1,2,3	2 per trip string	D	SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 200°F
2. Primary Containment Isolation					
a. Reactor Vessel Water Level – Low	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ 10.24 inches
b. Drywell Pressure – High	1,2,3	2	G	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.7	≤ 1.94 psig
c. Drywell Radiation – High	1,2,3	1	F	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 77 R/hr

(continued)

Table 3.3.6.2-1 (page 1 of 1)
Secondary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level − Low	1,2,3, (a)	2	SR 3.3.6.2.1 SR 3.3.6.2.2 SR 3.3.6.2.3 SR 3.3.6.2.5 SR 3.3.6.2.6	≥ ~~10.24~~ inches 2.65
2. Drywell Pressure − High	1,2,3	2	SR 3.3.6.2.2 SR 3.3.6.2.4 SR 3.3.6.2.6	≤ 1.94 psig
3. Reactor Building Exhaust Radiation − High	1,2,3, (a),(b)	2	SR 3.3.6.2.1 SR 3.3.6.2.2 SR 3.3.6.2.4 SR 3.3.6.2.6	≤ 14.9 mR/hr
4. Refueling Floor Radiation − High	1,2,3, (a),(b)	2	SR 3.3.6.2.1 SR 3.3.6.2.2 SR 3.3.6.2.4 SR 3.3.6.2.6	≤ 100 mR/hr

(a) During operations with a potential for draining the reactor vessel.

(b) During CORE ALTERATIONS and during movement of irradiated fuel assemblies in secondary containment.

ENCLOSURE 1 - ATTACHMENT C
Supplement to Request For Power Uprate Operation
Dresden Nuclear Power Station, Units 2 and 3

INFORMATION SUPPORTING A FINDING OF NO SIGNIFICANT HAZARDS CONSIDERATION

According to 10 CFR 50.92(c), "Issuance of Amendment," a proposed amendment to an operating license involves no significant hazards consideration if operation of the facility in accordance with the proposed amendment would not:

> Involve a significant increase in the probability or consequences of an accident previously evaluated; or
>
> Create the possibility of a new or different kind of accident from any accident previously evaluated; or
>
> Involve a significant reduction in a margin of safety.

In support of this determination, an evaluation of each of the three criteria set forth in 10 CFR 50.92 is provided below regarding the proposed license amendment.

Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

The proposed change revises the allowable value for the main steam line isolation function that occurs on reactor vessel water level – low low. The allowable value was recalculated using a wider and thus more conservative temperature range for the low low reactor vessel water level instrumentation. This primary containment isolation function is not involved in the initiation of accidents or transients previously evaluated. The proposed change does not result in any hardware changes. Existing operating margin between plant conditions and actual plant setpoints is not significantly reduced due to this change. As a result, the proposed change will not result in unnecessary plant transients or significantly increase the probability of an accident previously evaluated.

The purpose of the main steam line isolation function is to mitigate and thereby limit the consequences of accidents. The allowable value has been developed to ensure that the design and safety analysis limits will be satisfied. The methodology used for the development of the allowable value ensures the affected instrumentation remains capable of mitigating design basis events as described in the safety analyses and that the results and consequences described in the safety analyses remain bounding. Additionally, the proposed change does not alter the plant's ability to detect and mitigate events.

Therefore, this change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

Does the proposed change create the possibility of a new of different kind of accident from any accident previously evaluated?

The proposed change is the result of application of the instrumentation setpoint methodology specific to the analysis of instrument channel setpoint error and instrument loop accuracy. The proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated. This is based on the fact that the method and manner of plant operation is unchanged. The use of the proposed allowable value does not impact safe operation of the plant because the safety analysis limits will be maintained. The proposed allowable value involves no system additions or physical modifications to plant systems. This allowable value was developed using a methodology to ensure the affected instrumentation remains capable of mitigating accidents and transients. Plant equipment will not be operated in a manner different from previous operation. Since operational methods remain unchanged and the operating parameters have been evaluated to maintain the station within existing design basis criteria, no different type of failure or accident is created.

Therefore the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

Does the proposed change involve a significant reduction in a margin of safety?

The proposed change has been developed using a methodology to ensure safety analysis limits are not exceeded. As such, this proposed change does not involve a significant reduction in a margin of safety.

Conclusion

Therefore, the proposed change involves no significant hazards consideration.

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ENCLOSURE 1 - ATTACHMENT D
Supplement to Request For Power Uprate Operation
Dresden Nuclear Power Station, Units 2 and 3

INFORMATION SUPPORTING AN ENVIRONMENTAL ASSESSMENT

Exelon Generation Company (EGC), LLC has evaluated this proposed change against the criteria for identification of licensing and regulatory actions requiring environmental assessment in accordance with 10 CFR 51.21, "Criteria for and identification of licensing and regulatory actions requiring environmental assessments." EGC has determined that this proposed change meets the criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9), "Criterion for categorical exclusion; identification of licensing and regulatory actions eligible for categorical exclusion or otherwise not requiring environmental review," and as such, has determined that no irreversible consequences exist in accordance with 10 CFR 50.92(b), "Issuance of amendment." This determination is based on the fact that this change is being proposed as an amendment to a license issued pursuant to 10 CFR 50, "Domestic Licensing of Production and Utilization Facilities," which changes a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, "Standards for Protection Against Radiation," or that changes an inspection or a surveillance requirement, and the amendment meets the following specific criteria.

(i) The amendment involves no significant hazards consideration.

As demonstrated in Attachment C, the proposed change does not involve any significant hazards considerations.

(ii) There is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite.

The proposed change revises the allowable value for the main steam line isolation function that occurs on reactor vessel water level – low low. The change does not allow for an increase in the unit power level, does not increase the production, nor alter the flow path or method of disposal of radioactive waste or byproducts. Therefore, the proposed change does not affect actual unit effluents.

(iii) There is no significant increase in individual or cumulative occupational radiation exposure.

The proposed change will not result in changes in the operation or configuration of the facility. There will be no change in the level of controls or methodology used for processing radioactive effluents or handling of solid radioactive waste. The proposed change will not result in any change in the normal radiation levels within the plant. Therefore, there will be no increase in individual or cumulative occupational radiation exposure resulting from this change.

ENCLOSURE 2 - ATTACHMENT A

Supplement to Request For Power Uprate Operation
Quad Cities Nuclear Power Station, Units 1 and 2

DESCRIPTION AND SUMMARY SAFETY ANALYSIS FOR PROPOSED CHANGES

A. SUMMARY OF PROPOSED CHANGES

Pursuant to 10 CFR 50.90, "Application for amendment of license or construction permit," Exelon Generation Company (EGC), LLC, formerly Commonwealth Edison (ComEd) Company, is requesting additional changes to the Technical Specifications (TS) relative to the changes proposed in References I.1 and I.2 for the Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2. This proposed change identifies two additional TS tables that require changes to support the proposed change to the reactor vessel water level scram and isolation setpoint for QCNPS submitted in Reference I.1.

In Reference I.1, ComEd submitted a TS amendment request for QCNPS to allow operation with an extended power uprate (EPU). The amendment request proposed various TS changes, which included a change to the allowable value for the reactor vessel water level - low scram and isolation functions. The proposed change identified the allowable value change in TS Tables 3.3.1.1-1, "Reactor Protection System Instrumentation," and 3.3.6.1-1, "Primary Containment Isolation Instrumentation." During implementation reviews for the EPU, it was recognized that the same allowable value change was required in Table 3.3.6.2-1, "Secondary Containment Isolation Instrumentation," and Table 3.3.7.1-1, "Control Room Emergency Ventilation (CREV) System Isolation Instrumentation." The changes proposed in this attachment revise this allowable value in TS Tables 3.3.6.2-1 and 3.3.7.1-1.

Reference I.1 also proposed a change to the allowable value for the main steam line flow high isolation function contained in TS Table 3.3.6.1-1, "Primary Containment Isolation Instrumentation." During implementation reviews for the EPU, it was recognized that the same allowable value change should have been proposed for Table 3.3.7.1-1, "Control Room Emergency Ventilation (CREV) System Isolation Instrumentation." The changes proposed in this attachment revise this allowable value in TS Table 3.3.7.1-1.

B. DESCRIPTION OF THE CURRENT REQUIREMENTS

B.1 Reactor Vessel Water Level – Low

Table 3.3.6.2-1, Function 1, identifies the allowable value for the reactor vessel water level – low function. The allowable value is ≥ 11.8 inches.

Table 3.3.7.1-1, Function 1, identifies the allowable value for the reactor vessel water level - low function. The allowable value is ≥ 11.8 inches.

B.2 Main Steam Line Flow – High

Table 3.3.7.1-1, Function 3, identifies the allowable value for the main steam line flow – high function. The allowable value is ≤ 138% rated steam flow.

C. BASES FOR THE CURRENT REQUIREMENTS

C.1 Reactor Vessel Water Level - Low

A low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should the RPV water level decrease too far, fuel damage could result. An isolation of the secondary containment and actuation of the standby gas treatment system are initiated in order to minimize the potential of an offsite release. An isolation of the CREV system occurs since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

C.2 Main Steam Line Flow – High

High main steam line flow could indicate a break of a main steam line and therefore automatically initiates an isolation of the CREV system, since this could be a precursor to a potential radiation release and subsequent radiation exposure to control room personnel.

D. NEED FOR REVISION OF THE REQUIREMENTS

D.1 Reactor Vessel Water Level - Low

The loss of feedwater transient was reanalyzed under EPU conditions. Due to increased core heat generation as a result of EPU, the RPV water level decreases more rapidly in this transient. Therefore, the Reference I.1 amendment request proposed to lower the reactor vessel low water level scram setpoint in order to increase the potential for recovery before reaching the scram setpoint and thus prevent unnecessary challenges to safety systems and provide additional time for operator action.

The proposed changes to the allowable values for the secondary containment isolation and CREV system isolation functions on reactor vessel water level – low are directly related to the proposed change for the reactor scram setpoint reduction. To maintain the secondary containment isolation and CREV system isolation functions at the same level as the reactor scram function, the allowable values for TS Table 3.3.6.2-1, Function 1, and Table 3.3.7.1-1, Function 1, must be revised.

D.2 Main Steam Line Flow – High

The proposed change to the allowable value for the CREV system isolation on main steam line flow – high is directly related to the proposed change in Reference I.1 for the primary containment isolation function on main steam line flow – high in TS Table 3.3.6.1-1, Function 1.d. To maintain the CREV isolation function at the same level, the allowable value for TS Table 3.3.7.1-1, Function 3, must also be revised.

E. DESCRIPTION OF THE PROPOSED CHANGES

E.1 Reactor Vessel Water Level - Low

The allowable value for Table 3.3.6.2-1, Function 1, is revised from ≥ 11.8 inches to ≥ 3.8 inches.

The allowable value for Table 3.3.7.1-1, Function 1, is revised from ≥ 11.8 inches to ≥ 3.8 inches.

E.2 Main Steam Line Flow – High

The allowable value for Table 3.3.7.1-1, Function 3, is revised from ≤ 138% rated steam flow to ≤ 254.3 pounds per square inch differential (psid).

F. SUMMARY SAFETY ANALYSIS OF THE PROPOSED CHANGES

F.1 Reactor Vessel Water Level - Low

The reactor vessel water level - low function is assumed in the analysis of the recirculation line break and is credited in the loss of normal feedwater flow event. The reactor scram associated with the function reduces the amount of energy required to be absorbed and, along with the actions of the emergency core cooling systems, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46, "Acceptable criteria for emergency core cooling systems for light-water nuclear power reactors." The associated secondary containment isolation function is initiated in order to minimize the potential of an offsite release. Additionally, the CREV system isolation is initiated in order to minimize the potential dose to the control room operators. The allowable values for the secondary containment isolation function and CREV system isolation function are chosen to be the same as the allowable value for the reactor protection system setpoint and are not analyzed separately. The proposed change in the reactor scram setpoint does not result in a change to the current safety analyses. Thus, the change in the allowable value for the secondary containment isolation function continues to ensure that any offsite releases are within the limits calculated in the safety analysis. For the CREV system isolation function, the change in allowable value continues to ensure that the radiation exposure of control room personnel, as a result of a LOCA, does not exceed the limits set by GDC 19 "Control Room," of 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants."

F.2 Main Steam Line Flow – High

This proposed change is associated with the units of measurement for the allowable value. The proposed change revises the allowable value from units of percent rated steam flow to units of psid. This proposed change preserves the same allowable value in terms of percent rated steam flow (i.e., 254.3 psid is equivalent to 138% of uprated steam flow). Because of the increase in rated steam flow associated with the EPU, the proposed change increases the actual mass flow rate of steam required to actuate the isolation function. Since the maximum steam flow following a main steam line (MSL)

break does not change due to the flow restrictors, the proposed changes result in a decrease in the difference between the allowable value and the maximum flow. The purpose of the main steam line flow - High isolation function is to provide protection against pipe breaks in the MSL outside the drywell. For a complete severance of one MSL, steam flow increases almost instantaneously to the maximum steam flow as limited by the flow restrictors. Thus, the present and proposed setpoints would be attained virtually at the same time. Therefore, the consequences of a MSL break as evaluated in the UFSAR will remain unchanged with the increase in high flow setpoint.

G. IMPACT ON PREVIOUS SUBMITTALS

All submittals currently under review by the NRC were evaluated to determine the impact of these proposed changes. These proposed changes supplement the changes proposed to support uprated power operation at QCNPS in References I.1 and I.2.

In addition, these proposed changes affect the proposed changes submitted in Reference I.3, which requested that the NRC consider the proposed changes to the reactor water level – low setpoint separately from the EPU amendment request. The additional proposed change being submitted in this amendment request is also being submitted to the NRC separately as a supplement to the Reference I.3 amendment request.

No other submittals currently under review by the NRC are affected by the information presented in this supplemental license amendment request.

H. SCHEDULE REQUIREMENTS

We request that these proposed changes be reviewed and approved as part of the proposed changes for power uprate operation previously submitted in References I.1 and I.2.

I. REFERENCES

1. Letter from R. M. Krich (ComEd) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000
2. Letter from R. M. Krich (EGC) to U. S. NRC, "Supplement to Request for License Amendment for Power Uprate Operation," dated April 13, 2001
3. Letter from R. M. Krich (EGC) to U. S. NRC, "Request for License Amendment for Reactor Vessel Low Water Level Setpoint," dated February 22, 2001

ENCLOSURE 2 - ATTACHMENT B

Supplement to Request For Power Uprate Operation
Quad Cities Nuclear Power Station, Units 1 and 2

MARKED-UP TS PAGES FOR PROPOSED CHANGES

The marked-up Technical Specifications are provided in the following pages.

REVISED PAGES
3.3.6.2-4
3.3.7.1-4

Table 3.3.6.2-1 (page 1 of 1)
Secondary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level – Low	1,2,3, (a)	2	SR 3.3.6.2.1 SR 3.3.6.2.2 SR 3.3.6.2.3 SR 3.3.6.2.5 SR 3.3.6.2.6	≥ ~~11.8~~ 3.8 inches
2. Drywell Pressure – High	1,2,3	2	SR 3.3.6.2.2 SR 3.3.6.2.4 SR 3.3.6.2.6	≤ 2.43 psig
3. Reactor Building Exhaust Radiation – High	1,2,3, (a),(b)	2	SR 3.3.6.2.1 SR 3.3.6.2.2 SR 3.3.6.2.4 SR 3.3.6.2.6	≤ 9 mR/hr
4. Refueling Floor Radiation – High	1,2,3, (a),(b)	2	SR 3.3.6.2.1 SR 3.3.6.2.2 SR 3.3.6.2.4 SR 3.3.6.2.6	≤ 100 mR/hr

(a) During operations with a potential for draining the reactor vessel.

(b) During CORE ALTERATIONS and during movement of irradiated fuel assemblies in secondary containment.

Table 3.3.7.1-1 (page 1 of 1)
Control Room Emergency Ventilation (CREV) System Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level – Low	1,2,3, (a)	2	C	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.5 SR 3.3.7.1.6	≥ ~~11.8~~ inches 3.8
2. Drywell Pressure – High	1,2,3	2	C	SR 3.3.7.1.2 SR 3.3.7.1.4 SR 3.3.7.1.6	≤ 2.43 psig
3. Main Steam Line Flow – High	1,2,3	2 per MSL	B	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.5 SR 3.3.7.1.6	254.3 psid ≤ ~~130% rated steam flow~~
4. Refueling Floor Radiation – High	1,2,3, (a),(b)	2	B	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.4 SR 3.3.7.1.6	≤ 100 mR/hr
5. Reactor Building Ventilation Exhaust Radiation – High	1,2,3, (a),(b)	2	B	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.4 SR 3.3.7.1.6	≤ 9 mR/hr

(a) During operations with a potential for draining the reactor vessel.

(b) During CORE ALTERATIONS and during movement of irradiated fuel assemblies in the secondary containment.

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Nuclear

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RS-01-168

August 14, 2001

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

Reference: Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

In the referenced letter, Commonwealth Edison (ComEd) Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications (TS) for Dresden Nuclear Power Station (DNPS), Units 2 and 3, and Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2, to allow operation with an extended power uprate (EPU). In a July 18, 2001, telephone conference call between representatives of EGC and Mr. L. W. Rossbach and other members of the NRC, the NRC requested additional information regarding these proposed changes. The attachment to this letter provides a portion of the requested information. The remainder of the requested information will be provided in a separate letter.

Should you have any questions concerning this letter, please contact Mr. A. R. Haeger at (630) 657-2807.

Respectfully,

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

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Attachments:

Affidavit
Attachment: Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation

cc: Regional Administrator - NRC Region III
NRC Senior Resident Inspector - DNPS Nuclear Power Station
NRC Senior Resident Inspector - QCNPS Nuclear Power Station
Office of Nuclear Facility Safety - Illinois Department of Nuclear Safety

bcc: NRC Project Manager, NRR - DNPS Nuclear Power Station, Units 2 and 3
NRC Project Manager, NRR – QCNPS Nuclear Power Station, Units 2 and 3
Manager of Energy Practice - Winston and Strawn
Director-Licensing, Mid-West Regional Operating Group
Manager-Licensing, DNPS and QCNPS Stations
Regulatory Assurance Manager - DNPS Nuclear Power Station
Regulatory Assurance Manager – QCNPS Nuclear Power Station
D. Tubbs – MidAmerican Energy Company
W. Leech – MidAmerican Energy Company
Document Control Desk - Licensing (Hard Copy)
Document Control Desk - Licensing (Electronic Copy)

STATE OF ILLINOIS)

COUNTY OF DUPAGE)

IN THE MATTER OF)

EXELON GENERATION COMPANY, LLC) Docket Numbers

DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3) 50-237 AND 50-249

QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2) 50-254 AND 50-265

SUBJECT: Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Subscribed and sworn to before me, a Notary Public in and for the State above named, this 14th day of August, 2001.

Vicki L Farbo
Notary Public

OFFICIAL SEAL
VICKI L FARBO
NOTARY PUBLIC STATE OF ILLINOIS
MY COMMISSION EXP. NOV. 4, 2001

Attachment
Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 1 through 9, 12, and 13. Responses to NRC Questions 10 and 11 will be provided separately.

Question
1. *There is a modification being implemented in parallel with the extended power uprate that will install an automatic recirculation system runback following a feedwater pump trip. What is the impact of a spurious recirculation system runback at full or low power and what is the impact of a failure of the recirculation pump to runback at full or low power? How have these new events been addressed in the extended power uprate probabilistic safety assessment (PSA) model and what are their expected impacts on the trip initiating event frequency?*

Response
A brief summary of the responses is provided in the following tabular display followed by a more detailed description.

Failure Mode	Impact	EPU PRA	Trip Frequency
Spurious Initiation of Recirculation Pump Runback	Potential high reactor pressure vessel (RPV) water level, turbine trip, scram, and feedwater (FW) trip	Not quantitatively included; estimated as negligible	~1E-4/yr
Failure to Runback	Potential low RPV water level scram and turbine trip	Failure Probability estimated at 5.2E-3	None

Recirculation pump runback has been added to the design to avoid plant trips on loss of a single condensate or feedwater pump. This results in reducing the trip frequency for the extended power uprate (EPU) condition by avoiding the "new" scrams which are estimated at frequencies of 5E-2/yr for Quad Cities Nuclear Power Station (QCNPS) and 0.21/yr for Dresden Nuclear Power Station (DNPS).

There are, however, increases in scram frequency introduced by the addition of this control circuit due to spurious scrams. However, the increase in scram frequency is estimated at 1E-4/yr, or approximately two orders of magnitude less than the scram reduction achieved by the addition of the runback circuit.

Spurious Recirculation System Runback
The recirculation pump runback is designed to be an energize to actuate logic. This design was chosen to reduce any possibility of spuriously causing an RPV water level transient. Therefore, the logic failure that would induce a recirculation runback is calculated to be approximately 1.3E-2/yr, characterized as an "OR" gate of two relay failures (one to spuriously energize and one to spuriously de-energize) and an operating crew miscalibration. Spurious recirculation pump

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runback would lead to an RPV water level transient, which would challenge the feedwater control system. Spurious recirculation runback can be successfully mitigated by the feedwater control system maintaining RPV level below the high level scram setpoint to avoid a scram transient. Given a spurious recirculation system runback at full or low power, the feedwater control system is judged to adequately reduce feedwater flow to the RPV to match the decrease in recirculation flow. However, if the feedwater control system cannot reduce flow in sufficient time, the reactor would scram and the feedwater pumps would trip on high RPV level. The event would be similar to a turbine trip transient with the feedwater pumps remaining available to be restarted. Spurious runback is less likely at low power because the runback circuit is not enabled at power levels below current rated thermal power.

This combination of failures (spurious recirculation runback and failure of feedwater control) is estimated at 1E-4/yr.

The total turbine trip frequency is approximately 2.0/yr from all causes. Therefore, an increase of 1E-4/yr. is judged to be a negligible change to the initiating event frequency. Whether at full power or low power, spurious recirculation runback is a low frequency event that is subsumed by higher frequency initiating events already evaluated for the EPU condition (e.g., turbine trip).

Failure of the Recirculation System Runback

Failure of the recirculation system runback at full flow is explicitly evaluated for the EPU condition. Initial analyses indicated that the recirculation runback modification may not sufficiently reduce flow in the event of a feedwater or condensate/booster pump trip to prevent a low RPV water level scram. Therefore, the turbine trip initiating event frequency was increased to account for failure of any single feedwater or condensate/booster pump to result in a turbine trip. Based on plant specific analyses, the QCNPS turbine trip initiating event frequency increased from 2.0/yr to 2.05/yr and the DNPS turbine trip initiating event frequency increased from 1.14/yr to 1.35/yr. The risk associated with this initiating event frequency increase has been calculated and included in the delta risk calculations.

Subsequent analyses, however, indicate that the recirculation runback system would operate as designed and be able to prevent RPV level from reaching the low level scram setpoint given loss of a feedwater or condensate/booster pump (i.e., no increase in turbine trip initiating event frequency). Since the subsequent analyses was not available prior to completion of the EPU risk assessment, the increase in turbine trip initiating event frequency was incorporated into the base EPU risk model (see response to Question 3).

Failure of the recirculation pump runback at low flow is not explicitly evaluated for the EPU condition. When the reactor is at low power, the plant is likely to be operating in the pre-EPU condition with two of the three feedwater pumps and three of four condensate/booster pumps operating. For this condition, if a pump trips, the standby pump automatically starts and a low RPV level scram can be avoided.

Attachment
Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Question

2. There is a modification being implemented to trip the fourth running condensate pump during a loss of coolant accident (LOCA) to prevent an electrical overload. Is this modification being hardwired to a specific condensate pump? If the pump fails to trip or its breaker(s) fails to open, what is the impact on the electrical system? Were these new potential failure modes of the electrical system explicitly modeled? If not, please explain the basis for these failures modes being considered to have a negligible impact.

Response

The modification will add a logic circuit to automatically trip condensate/booster pump "D" in the event of a LOCA while all four condensate pumps are running. The intent of the modification is to prevent a potential overload condition on the reserve auxiliary transformer (RAT) in the event of a LOCA with offsite power available. The LOCA would cause a unit trip, resulting in deenergizing the unit auxiliary transformer. Running loads would then transfer to the RAT. Without this modification, the starting of emergency core cooling system (ECCS) pumps could result in undervoltage on the 4kV buses. The undervoltage signal would then result in ECCS loads being powered from the emergency diesel generators, but the condensate and feedwater pumps would trip. Therefore, the condensate and feedwater pumps would not be available for injection without further operator action. Since offsite power can still be manually restored to the 4kV buses, this scenario would be bounded by the LOCA with loss of offsite power (LOOP).

There are two contact inputs from the LOCA detection circuits, each from a different division circuit, arranged in parallel. Failure of either contact to actuate on a LOCA will not prevent the desired trip of condensate pump motor "D." Multiple failures or a common cause failure (CCF) across two divisions would be required to prevent the receipt of the trip signal. Since failure of the trip circuit only results in ECCS loads being powered from the diesels as designed, additional failures must be postulated for this sequence to result in core damage.

The quantitative impact of the new failure mode was conservatively calculated as follows.

Core damage frequency (CDF) = (LOCA signal initiating event frequency) x (Failure to trip condensate/ booster pump "D" x (Single unit LOOP induced))(1) x (Failure to cross tie alternating current (AC) buses to opposite unit) x (Failure of all diesel generators + other failure combinations)

= (1E-2/yr) x (1E-3) x (1.0) x [(1.1E-2) x (1E-3) + 3E-6]

= 1.68E-10/yr

where failure to trip pump "D" can be due to failure of the logic or failure of the breaker to open.

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(1) This quantitative assessment conservatively assumes that the failure of the breaker to trip ~~will~~ cause a LOOP event with a 1.0 probability, AND no offsite AC power recovery is credited even though the RAT and offsite power remain available.

The screening analysis was performed as follows:

- The frequency of any initiating event that could result in a LOCA signal was summed to find the potential for the load shed signal. This includes the sum over all frequencies for LOCAs, loss of drywell cooling, loss of service water (SW), and loss of reactor building closed cooling water (RBCCW).

- The conditional probability that the condensate pump was not shed is estimated using a common cause miscalibration of the control system, plus relay failure, plus a circuit breaker failure to trip (8E-5 + 1E-4 +1E-3)

- The conditional probability that BOP systems are not available because of the unavailability of non-safety related power is assumed to be 1.0 for this screening analysis.

- The conditional probability of subsequent failures leading to core damage is dominated by the failure to supply alternating current (AC) power. This is characterized by the failure of all diesels capable of supplying the unit (~1E-3) and failure to supply AC power from the opposite unit (~1.1E-2). Other failure combinations represent approximately 30% of this conditional probability or 3E-6.

The additional CDF contribution of 1.68E-10/yr from this failure mode is negligible compared to the base CDF of 4.6E-6/yr for QCNPS and 2.6E-6/yr for DNPS. Therefore, this failure mode was not explicitly evaluated for the EPU probabilistic risk assessment (PRA) sensitivity quantification.

Spurious Actuation Events
In addition to the above failure mode of failure to successfully load shed, there could be a spurious condensate pump trip event due to a failure in the new circuit. Spurious trip of a condensate pump due to the relay energizing spuriously is 4.4E-3/yr.

This represents a negligible increase in the turbine trip frequency because of the following.

- Relay spuriously energizes ~4.4E-3/yr
- Condensate pump trips ~1.0
- Recirculation pump does not runback ~5.2E-3

This results in a 2E-6/yr turbine trip initiating event frequency increase. The scram frequency change is already adequately encompassed by the change included in the recirculation pump runback circuit addition (see response to Question 3).

Question

3. The change in turbine trip initiating event frequency is stated to be the result of the need to operate the installed spare feedwater and condensate/condensate booster pumps.

3.1. How was the change in initiating event frequency determined? Was a plant-specific loss of feedwater initiating event model explicitly revised to include the potential failure of the required operating pumps or was the initiating event scaled to account for the additional failure modes? If the latter, please provide a justification for the applicability of the plant-specific initiating event data used in these calculations due to the change in operating conditions and configurations.

3.2. The DNPS information indicates that the loss of any single feedwater or condensate/condensate booster pump would lead to a reactor low level scram signal, but the QCNPS information indicates that this is estimated to occur only half of the time. Please explain why there is this difference between the DNPS and QCNPS loss of feedwater initiating event models.

Response

3.1 QCNPS

For QCNPS, the turbine trip initiating event frequency change associated with the configuration change was developed with a plant specific fault tree model for the initiating event to account for the additional failure modes. A simplified fault tree model was developed to estimate the increase in the turbine trip initiating event frequency due to the modified feedwater/condensate configuration to support EPU.

The EPU configuration increases the number of normally operating feedwater pumps from two to three and the number of normally operating condensate pumps from three to four. Due to the increased feedwater flow rate to accommodate EPU, preliminary analyses indicated that the recirculation runback logic may not sufficiently reduce flow in the event of a feedwater or condensate/booster pump trip to prevent a low RPV level scram. Subsequent analyses, however, indicate that the recirculation runback system would operate as designed and be able to prevent RPV level from reaching the low level scram setpoint given loss of a feedwater or condensate/booster pump (i.e., no increase in turbine trip initiating event frequency). However, the analyses were not available prior to completion of the EPU risk assessment. Therefore, the risk assessment incorporated the increase in turbine trip initiating event frequency in the base EPU risk model.

The simplified model includes the following assumptions:

- Failure of any single feedwater or condensate pump to run during the year may lead to a plant trip. The plant trip is classified as a turbine trip and not a loss of feedwater event because, in most cases, one or more feedwater pumps will remain available. Failure of the recirculation runback logic to automatically reduce flow and prevent a trip is assigned a failure probability of 0.5.

- Failure to run rates for feedwater pumps (i.e., 2.59E-6/hr) and condensate pumps (i.e., 8.44E-7/hr) are taken from the QCNPS 1999 PRA update.

- The run time is assumed to be 8760 hours (i.e., 1 year) per pump.

- Additional component failures have not been included in this simplified analysis (e.g., feedwater heaters, condensate booster pumps, lube oil pumps). These failures are assumed to be subsumed by the feedwater and condensate pump failure rates

The fault tree model results estimate that the turbine trip initiating event frequency increases from the base QCNPS PRA value of 2.0/yr to approximately 2.05/yr due to the power uprate configuration.

3.1 DNPS

For DNPS, the turbine trip initiating event frequency was also developed to account for the additional failure modes. Similar to QCNPS, a simplified fault tree model was initially developed to estimate the increase in the turbine trip initiating event frequency due to the modified feedwater/condensate configuration to support power uprate. However, the failure to run rates for feedwater pumps (i.e., 2.5E-5/hr) and condensate pumps (i.e., 3.0E-5/hr), taken from the DNPS 1999 PRA update, are an order of magnitude higher than QCNPS. Therefore, the simplified fault tree methodology resulted in a calculated increase in turbine trip frequency that was judged to be unrealistically conservative. The higher feedwater and condensate pump failure rates are based on the DNPS IPE. The higher feedwater and condensate pump failure rates have a negligible impact on the base DNPS PRA model results.

As an alternate methodology for DNPS, plant specific data was reviewed to determine how many feedwater and condensate pump trips have occurred that did not result in plant scrams in the pre-uprate condition but would have resulted in plant scrams in the post-uprate condition if the recirculation system runback was ineffective. Based on this review, three additional turbine trips over a seven year period would have occurred. This equates to an initiating event increase of 0.43/yr/2 units, or 0.21 turbine trips per unit.

The plant specific data analysis estimates that the turbine trip initiating event frequency increases from the base DNPS PRA value of 1.14/yr to approximately 1.35/yr due to the power uprate configuration.

As noted for QCNPS, subsequent analyses indicate that the recirculation runback system would operate as designed and be able to prevent RPV level from reaching the low level scram setpoint given loss of a feedwater or condensate/booster pump (i.e., no increase in turbine trip initiating event frequency). However, the analyses were not available prior to completion of the EPU risk assessment. Therefore, the risk assessment incorporated the increase in turbine trip initiating event frequency in the base EPU risk model with no credit for the recirculation pump runback.

Therefore, on a realistic basis the increase in risk associated with this turbine trip frequency increase should be removed, i.e., the quantified QCNPS EPU CDF risk would decrease by approximately 1% from 5% to 4%. Similarly, the DNPS EPU CDF would decrease by approximately 2.5% from 9% to 6.5%.

3.2 QCNPS and DNPS

For QCNPS, a value of 0.5 was used to estimate that the recirculation runback system would fail to prevent a low level scram signal given failure of a feedwater or condensate/booster pump. The value of 0.5 is based on a conservative judgement because preliminary analyses indicated that the recirculation runback system might not be capable of preventing a low level scram signal. Using a value of 1.0 instead of 0.5 for failure of the recirculation runback system for QCNPS would have resulted in a CDF and large early release frequency (LERF) increase of less than an additional 1% over the base EPU case.

The DNPS analysis was performed later and used a value of 1.0 to estimate that the recirculation runback system would fail to prevent a low level scram signal. The value of 1.0 was used to account for the additional uncertainty associated with using engineering judgement to determine if the failed feedwater or condensate/booster pump described in the event reports would lead to a scram in the post-uprate condition.

For both plants, failure of the recirculation runback system is modeled conservatively because subsequent analyses indicate that the recirculation runback system would function as designed to prevent a low RPV level scram signal given loss of a feedwater or condensate/booster pump. The use of the conservative values yielded acceptably small increases in the risk.

Question

4. It is expected that the time to initiate standby liquid control (SBLC) early would also be impacted, as well as its late initiation, but this impact is not identified. What was the impact on early SBLC initiation as a result of the extended power uprate in terms of available time and associated human error probability (HEP) and what was its overall impact on core damage frequency (CDF)?

Response

DNPS and QCNPS

The manual initiation of SBLC has been divided into two time phases. The two time phases are defined solely be for the purpose of characterizing the following.

- "Early" time phase is a condition corresponding to the expected operating crew response to follow procedures and take prompt action as specified by the symptom based procedures. This results in a more controlled response to the anticipated transient without scram (ATWS) event and the ability to avoid a demand for emergency depressurization due to exceeding the heat capacity temperature limit (HCTL).

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- "Late" time phase that characterizes the absolute latest time when crew action can be taken to prevent core damage. The plant condition would have deteriorated substantially and increased difficulty in controlling RPV injection is modeled to prevent core damage.

From a probabilistic risk assessment standpoint, the "early" success paths are more reliable. The demarcation time for the early time phase was conservatively represented in the pre-EPU PRA. The deterministic calculations performed as part of the EPU assessment indicated this time to be adequate and therefore no change was made to the timing or HEP associated with "early" SBLC initiation. The deterministic calculations show that the "late" time phase which was realistically assessed in the pre-EPU case does decrease for the post-EPU case.

The time available to initiate SBLC (early), prior to the condition where HCTL cannot be prevented, is estimated based on generic boiling water reactor (BWR) analysis to be approximately 6 minutes. The Modular Accident Analysis Package (MAAP) calculations for the power uprate configuration for QCNPS and DNPS confirm that SBLC initiation at 6 minutes is adequate to prevent reaching HCTL. Therefore, no change to the HEP for early SBLC initiation was required.

Question
5. The success criteria is stated to change in two areas: number of electromatic relief valves (ERVs) or safety relief valves (SRVs) required for reactor pressure vessel (RPV) depressurization and number of safety valves (SVs), ERVs, or SRVs required for overpressurization protection.

5.1. It is noted that the RPV depressurization sequences without a stuck open relief valve are dominated by operator action failures and common cause failures (CCFs). However, the CCF modeling, and thus its contribution, will be impacted due to the change in success criteria. Was the CCF modeling and associated values changed to reflect the change in success criteria for the post-uprate model? If so, what were the CCF values used in the pre- and post-uprate models and what was the quantified change in CCF contribution? If not, what is the basis for the conclusion that the impact is negligible?

5.2. The ATWS overpressure protection success criteria changes from 11 of 13 to 12 of 13 SVs, ERVs, or SRVs, which is stated to have a negligible impact on the results because it is dominated by CCF. Note that the post-uprate model would have to consider the CCF of any two valves, which was not considered in the pre-uprate model (it modeled the CCF combination of any three valves). Thus, the CCF contribution will be impacted due to this change in success criteria. Was the CCF modeling and associated values changed to reflect the change in success criteria? If so, what were the CCF values used in the pre- and post-uprate models and what was the quantified change in CCF contribution? If not, what is the basis for the conclusion that the impact is negligible?

Response

5.1 QCNPS

The success criteria for RPV depressurization for a transient without a stuck open relief valve (SORV) are the following:

Plant Condition	Depressurization Success Criteria[1] ERVs/SRVs	Failure Combination Required ERVs/SRVs
Pre-EPU	1 of 5	All 5
Post-EPU	2 of 5	Any 4

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(1) QCNPS includes 4 ERVs and 1 Target Rock SRV for depressurization.

The common cause treatment requires the failure combinations noted in the table. The data used for the common cause evaluation is based on Multiple Greek Letter (MGL) data contained in INEL 94/0064 (Reference 1), (including the identification of an additional failure mode noted in precursor events due to inadvertent insulation coverage on the valve top works), which is the predecessor to NUREG/CR-5497 (Reference 2).

These result in the following CCF probabilities used for QCNPS:

Plant Condition	ERV MGL CCF Probability 4 of 4	Precursor Failure Probability Failure of All SRVs/ERVs 4 of 5	Total Hardware Failure Probability[1]
Pre-EPU	2.8E-4	1.47E-4	1.47E-4 (5 of 5)
Post-EPU	2.8E-4	1.47E-4	4.27E-4 (Any 4)

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(1) Random contributions are neglected.

Class IA and IIIB (i.e., high pressure core damage) is increased by this change in CCF probability resulting in an increase in Class IA and IIIB of 1%. This change was identified in the risk evaluation performed to support the EPU.

The change in CDF remains relatively small because of the large diversity in high pressure makeup systems for QCNPS. The dominant contributors to Class IA and IIIB are related to DC power system failures that affect multiple ERVs and the SRV and multiple high pressure injection sources.

DNPS

The ERV/SRV configuration and success criteria are similar between DNPS and QCNPS. The dominant failures of the ERV/SRVs to depressurize the reactor at DNPS are also similar to QCNPS. Therefore, the results for DNPS are approximately the same (i.e., a 1% increase in CDF). The impact on CDF at DNPS is lessened by an isolation condenser (IC) that acts as a method to maintain RPV inventory and avoids challenging RPV makeup systems.

5.2 QCNPS and DNPS

The success criteria for RPV overpressure protection for an ATWS are the following:

Plant Condition	Overpressure Protection Success Criteria ERVs/SRVs/SVs	Failure Combination ERVs/SRVs/SVs
Pre-EPU	11 of 13	3
Post-EPU	12 of 13	2

The common cause treatment requires the failure combinations noted in the table. The data used for the common cause evaluation is based on NUREG/CR-5497 and its predecessors. NUREG/CR-5497 and its predecessors do not have CCF of the relief mode of BWR SRVs. Other estimates were used because the NUREG/CR-5497 evaluation found that the data identified no BWR safety valve CCF events and provided no other guidance.

The CCF estimates are based on industry data:

λ = 3E-3 (NUCLARR data)
β = 6.0E-2 (ALWR data)
γ = 1.0 (ALWR data)

The approach taken in the modeling is a BETA factor approach. If two valves fail, all valves are assumed to fail. Therefore, the probability of three valves failing due to common cause had conservatively already been assumed to be as high as the probability of two valves failing due to common cause. Multiplying these values results in the following failure probabilities for QCNPS and DNPS.

Plant Condition	ERV/SRV/SV MGL CCF
Pre-EPU 3 of 13	1.8E-4
Post-EPU 2 of 13	1.8E-4

<u>Question</u>

6. The DNPS (QCNPS) value for CDF is stated to change from 2.61E-6/year (4.61E-6/year) to 2.82E-6/year (4.85E-6/year) and the value for LERF is stated to change from 1.44E-6/year (3.30E-6/year) to 1.58E-6/year (3.43E-6/year). Typically, it is expected that the LERF value would be nearly an order of magnitude below the CDF value. Please explain why the LERF values at these sites are less than a factor of two below the CDF values.

<u>Response</u>

<u>QCNPS and DNPS</u>

DNPS and QCNPS have BWR Mark I containments. The NRC and the industry in the IPEs have evaluated these containments in the past (Reference 3). In nearly all the analyses, the failure modes associated with BWR Mark I containments that can lead to large releases have been quantified to have relatively high conditional probabilities. As an example, consider the results of the NRC evaluation of risk at a Mark I containment performed as part of NUREG-1150:

> "The important conclusions that can be drawn ... [are]: (1) there is a high mean probability (i.e., 50%) that the Peach Bottom containment will fail early for the dominant plant damage states; (2) early containment failures will primarily occur in the drywell structure resulting in a bypass of the suppression pool's scrubbing effects for radioactive material released after vessel breach; and (3) the principal cause of early drywell failure is drywell shell melt through. The data further indicate that the early containment failure probability distributions for most plant damage states are quite broad."

Quantitatively, NUREG-1150 cites the following:

> "...the mean conditional probability from internally initiated accidents of (1) early wetwell failure is about 0.03, (2) early drywell failure is about 0.52, (3) late failure of either the wetwell or drywell is about 0.04, and (4) no containment failure is about 0.27."

The containment failure analysis for QCNPS and DNPS, while resulting in slightly higher containment failure probabilities than those in NUREG-1150, are within the uncertainty ranges alluded to in the NUREG-1150 evaluation. The specific items that have impacted the QCNPS and DNPS calculations are as follows:

A. The analysis follows the simplified and conservative approach described in NUREG/CR-6595 (Reference 4). This introduces some conservatism into the analysis.
   - Dependencies are treated conservatively.
   - No credit is given to the reactor building for a decontamination factor on the release fraction.
   - No additional deterministic calculations were performed to support lower releases.

B. The use of drywell (DW) sprays with the latest severe accident management guidelines (SAMGs) (implemented after the PRA freeze date) has not been factored into the analysis. Therefore, the drywell shell melt through effect is higher than at other BWRs with the SAMGs included.

C. The ATWS induced failures of containment have been treated as LERF.
   - The frequency is based on the old ATWS conditional probabilities from NUREG-0460 (Reference 5), instead of the latest NUREG/CR-5500 (Reference 6) estimates. Because the QCNPS and DNPS CDF is relatively low, the ATWS fraction represents a substantial fraction of the overall CDF and release and these are all treated as LERF.
   - No deterministic calculations were performed to support lower releases under certain ATWS scenarios.

In summary, the QCNPS and DNPS evaluation of LERF is judged to be conservative. The reported conditional probability of LERF using the streamlined approach from NUREG/CR-6595 is at the high end of the spectrum of uncertainty for Mark I containments. There are, however, no unique or unusual plant configurations or hardware that make either QCNPS or DNPS more susceptible to LERF than other free-standing steel Mark I containments in the U. S.

Question

7. The response to the Human Factors RAIs implies there are different values used for HEPs at the different units at the same site, but this is not clear since the information provided seems to be primarily for one unit and only one set of CDF and LERF values is provided for a site. Are there different PRA models and data used for the individual units at each site or is a common model and data employed for both units at each site?

Response

QCNPS

Different operator actions and HEPs are not used in the EPU analysis. The HEPs used in the QCNPS EPU analysis are representative of operating crew interactions on both QCNPS Units 1 and 2. The calculated changes in CDF and LERF are approximately the same for both units; only Unit 1 results are quoted.

DNPS

The same holds true for the DNPS Units 2 and 3 EPU evaluations, i.e., only a single unit is assessed.

Question

8. Did the licensee re-perform the thermal hydraulic code analysis to establish the post-uprate PSA model success criteria and did this re-evaluation consider the numerous setpoint changes (e.g., reactor low water level, main steam line high flow, condenser vacuum), operational changes (e.g., recirculation pump runback feature, all feedwater and condensate pumps operating), and condition changes (e.g., higher decay heat load, higher ATWS peak pressures)? Did the evaluation specifically include the consideration of the operability of pumps (e.g., NPSH) that take suction from the torus, which will have a higher temperature condition as part of the extended power uprate? Please describe the supporting thermal hydraulic evaluations performed to determine the post-uprate PSA success criteria.

Response

DNPS and QCNPS

The MAAP is used to calculate changes in the thermal hydraulic profile for specific issues (e.g., boildown timing). The boildown time decreases as a result of increasing the power from 2511 megawatt-thermal (MWth) to 2957 MWth. The value of 2957 MWth represents the licensed power uprate. A thermal hydraulic analysis has been performed for a value of 2898 MWth that equates to the desired heat output of 912 MWe. This value comes from the heat balance developed for the EPU condition. For the power uprate configuration, the plant will be operated at 2898 MWth. Therefore, the MAAP runs performed to support the power uprate use a value of 2898 MWth instead of the licensed uprate value of 2957 MWth.

For the EPU project, the MAAP evaluations were performed for QCNPS as the base case for both QCNPS and DNPS, since the thermal hydraulic parameters are the same for the two sites.

MAAP is an industry recognized thermal hydraulics code used to evaluate design basis and beyond design basis accidents. MAAP (Version 3.0B) has been used to support the PRA for performing best estimate calculations. The QCNPS plant description is based on the plant specific MAAP parameter file Q1SIR10.PAR dated January 7, 1993. This parameter file contains plant specific parameters representing the primary system and containment.

The EPU changes were examined qualitatively to identify those that would potentially modify success criteria, timing, or equipment operability (e.g., net positive suction head (NPSH)). The result of that qualitative evaluation was the identification that:

- Emergency depressurization success criteria could be affected. Therefore, a special MAAP calculation was performed to support the revised success criteria used for EPU.
- ATWS overpressure success criteria was identified as another possible impact. General Electric (GE) calculations for EPU were used to support modification of the success criteria, not MAAP calculations.
- Timing for some operator crew actions were identified that could change or influence the HEP calculation. Therefore, selected MAAP runs were performed to support the changes in available time. These were all performed at the EPU initial power level.

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The NPSH for pump operability has been evaluated in the PRA. It is not limiting in the severe accidents evaluated except for those complete loss of decay heat removal (DHR) sequences with either a failed or vented containment. No change in this is found for the EPU conditions. Small changes in torus temperature do not impact pump operability due to NPSH.

MAAP is used for the power uprate evaluation to calculate the impacts of increased power level and changes to operating procedures (e.g., HCTL curve). Specifically, MAAP was used to calculate the revised accident timings or confirm existing success criteria for the following.

- Determine number of SRV/SVs required to be available for pressure control success criteria (transient and ATWS)
- Determine if 1 ERV/SRV is sufficient for emergency depressurization success criteria (transient and ATWS)
- Calculate time available for operator for emergency depressurization (transient, LOCA and ATWS)
- Verify for medium water break LOCA that initial HPCI/RCIC operation is sufficient for RPV depressurization success criteria.
- Verify that operator action time to initiate SBLC (early) and RPV level/power control (early) is sufficient to prevent reaching the HCTL
- Calculate the operator action time to initiate SBLC "late" and RPV level/power control "late" is sufficient to maintain suppression pool temperature below 260°F (the assumed containment failure criteria for ATWS)

Extensive analysis has also been performed to support the licensing and ATWS basis for EPU. The specific items are addressed as follows.

- Setpoint changes in main steam line flow and condenser vacuum are addressed in response to Question 13.
- The reactor low water level scram setpoint is discussed below.
- The recirculation runback feature is discussed in response to Question 1.
- The operation of all feedwater and condensate pumps is discussed in response to Question 3.
- The higher decay heat level was included in the revised thermal hydraulic calculations at the higher power level of 2898 MWth (full power).
- The higher peak ATWS pressures were explicitly evaluated using GE proprietary codes. These results were then factored into the revised EPU success criteria (see response to Question 5).
- The NPSH was monitored in the updated calculations to assess pump operability in the severe accident sequences as described in the above response.

Scram Setpoint

The reduction in scram setpoint on low RPV water level was not initially examined as part of the EPU PRA evaluation since it had not been identified as a change to the plant prior to the EPU PRA evaluation. This change has recently been evaluated consistent with the process used to evaluate identified plant modifications for PRA impact and has resulted in the following.

Initiating Events: Added margin to prevent a scram is obtained. This should decrease the initiating event frequency. Other hardware changes may increase the frequency of low RPV water level challenges. The net effect may be a zero impact (unquantifiable).

Success Criteria: The successful prevention of a scram given a transient such as loss of a single condensate pump may be improved. This would prevent initiating event scrams and reduce overall risk.

Accident Sequences: No new sequences or changes in sequence probability are identified.

Human Reliability Analysis: The time available for the crew to prevent scrams increases by a very small amount. Following a scram, the time for crew response to initiate make-up or RPV depressurization decreases by a very small amount. These effects are considered negligible.

Data: No quantifiable impact at this time.

Dependency: No dependency changes are identified.

Level 2: No quantifiable impact on severe accident progression or timing is identified.

Success Criteria and Accident Timing

The delay in scram on low RPV water level may result in slightly reduced operating crew action times for:

- RPV make up initiation
- Depressurization
- Time for DHR initiation

However, the change in setpoint of eight inches is judged to represent such a small incremental change that the impact on the system success criteria or operator error rate is not considered measurable.

A summary of the MAAP results to support EPU is provided in Table 8-1.

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered[3]	Max Core Temp (°F)	HCTL[2] (160°F)	Comments
Case QC1A1	Main steam isolation valve (MSIV) closure, no high pressure (HP) injection, delayed emergency depressurization (ED) at minimum steam cooling water level limit (MSCWLL)[1] and 1 containment spray (CS) pump • MSIV closure at t=0 • Only 3 SVs/ERVs available for initial pressure transient which operated as designed • No HP injection • ED at minimum steam cooling water level limit (using only 1 ERV) • Initiate 1 CS pump at low pressure (LP) interlock	• Verify 3 SVs/ERVs are still OK for pressure control to prevent exceeding RPV pressure operability limits (success criteria) • Verify that 1 ERV is still OK for RPV ED (success criteria)	39 min	1740	2.5 hrs.	Peak RPV pressure of 1130 psig ED at 37 min CS begins to inject at 59 min when shutoff head is reached

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered[3]	Max Core Temp (°F)	HCTL[2] (160°F)	Comments
Case QC1A2	MSIV Closure, no HP Injection, delayed ED (at 1/3 core height), and 1 CS pump • MSIV Closure at t=0 • Only 3 SVs/ERVs available for initial pressure transient • No HP injection • ED at 1/3 core height (using only 1 ERV) • Initiate 1CS pump at LP interlock	• Verify that 1 ERV is still OK for RPV ED (success criteria)[4] • Verify time allowable for manual initiation of automatic depressurization system (ADS) HEP (1ADOP-DEP-ADSH)[5]	40 min	Melt (> 4000°F)	2.28 hr	Peak RPV pressure of 1130 psig ED at 1.16 hr CS begins to inject at 1.4 hr when shutoff head is reached
Case QC1A3	Same as QC1A1 except: • 1 low pressure coolant injection (LPCI) instead of 1 CS • ED at –164" instead of –134"		40 min	2630	2.7 hr	LPCI flow > 0 at 1.1 hr ED at 45 min
Case QC1A4	Same as QC1A2 except: • 1 LPCI instead of 1 CS		40 min	Melt	1.9 hr	LPCI flow > 0 at 1.5 hr ED at 1.2 hr

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered(3)	Max Core Temp (°F)	HCTL(2) (160°F)	Comments
Case QC3B1	Medium water break LOCA, high pressure coolant injection (HPCI) available, 1 LPCI pump, and no ED • MLOCA 0.05 ft^2 (3" ID water break) at t=0 • HPCI auto cycling until RPV pressure below 100 psig • No ED • Initiate 1 LPCI pump when RPV pressure below shutoff head	• Verify viability of LP injection for MLOCA with HPCI and no ED (MLOCA ET success criteria)	N/A	Normal	3.4 hr	Peak RPV pressure of 1130 psig HPCI tripped when RPV pressure below 100 psig at 2.4 hrs HPCI level control between initiation level and +2 ft Operation of HPCI decreases RPV pressure LPCI flow > 0 at 18.8 min
Case QC3B2	Medium water break LOCA, no HP injection available, delayed ED (at 1/3 core height) and 1 LPCI pump • MLOCA 0.05 ft^2 (3" ID water break) at t=0 • No HP injection • ED at 1/3 core height (using only 1 ERV)	• Verify time allowable for manual initiation of ADS HEP (1ADOPMDEP-ADSH) for MLOCA	7.8 min	2250	3.4 hr	ED at 20 min due to 1/3 core height Peak RPV pressure of 1130 psig LPCI flow > 0 at 28 min

Attachment
Additional R sk Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered[3]	Max Core Temp (°F)	HCTL[2] (160°F)	Comments
	• Initiate 1 LPCI pump when RPV pressure below shutoff head					
Case QC4A1	Isolation ATWS, water controlled with HPCI, early SBLC injection • MSIV closure ATWS at t=0 • Recirculation pump trip (RPT) successful if high dome pressure reached • All SVs/ERVs available[6] • HPCI only injection source • Level controlled between top of active fuel (TAF) and TAF + 5' at 6 mins • SBLC w/2 pumps initiating at 6 min • Decay heat removal with 1 RHR loop (1 RHR pump and RHRSW pump) initiated at 10 min • DW sprays not available • All other presented actions in	• Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided[7]	3 min	Normal	15 min	Peak RPV pressure of 1870 psig ED on HCTL at 15 min Peak torus pressure of 22 psig To model effect of SBLC injection, power assumed to linearly decay from whatever level is predicted by Chexal-Layman correlation at 6 minutes and the time to shutdown of

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered[3]	Max Core Temp (°F)	HCTL[2] (160°F)	Comments
	EOPs to be taken e.g.: - RPV depressurization when HCTL - Vent containment at PCPL					6 + 24 = 30 min (24 minutes based on estimated time to inject SBLC inventory) RPT at 12 sec due to high RPV pressure Maximum pool temperature of 200°F
Case QC4A2	Same as Case QC4A1 except control RPV level with simultaneous FW and HPCI injection • FW injection until hotwell depleted • HPCI automatically initiated and cycling on level	• Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided[7]	3 min	Normal	14 min	Peak RPV pressure of 1940 psig ED at 14 min Peak torus pressure of 22 psig RPT at 13 sec due to high RPV press Maximum pool temperature of 200°F

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

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Case ID	T-H Run Description	Purpose	Core Uncovered[3]	Max Core Temp (°F)	HCTL[2] (160°F)	Comments
						FW tripped off when hotwell depleted at 30 sec
Case QC4A3	• All SVs/ERVs available • FW until hotwell depleted • HPCI automatically initiated and cycling on level • ED on HCTL • Level controlled between TAF and + 5ft at 20 min using 1 LPCI pump • SBLC w/2 pumps initiated at 20 mins • Decay heat removal with 2 RHR loops (1 RHR pump and 1 RHRSW pump per loop) initiated at 10 mins • DW sprays not available • All other presented actions in EOPs to be taken e.g.,	• Verify time available for delayed SBLC injection and RPV water level control[8]	3 min	Normal	11 min	Peak RPV pressure of 1940 psig ED on HCTL at 11 min Peak torus pressure of 39 psig RPT at 13 sec due to high RPV pressure Maximum pool temperature of 280°F FW tripped off when hotwell depleted at 30 sec

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR QCNPS AND DNPS 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered(3)	Max Core Temp (°F)	HCTL(2) (160°F)	Comments
Case QC4A3 cont'd	- RPV depressurization when HCTL - Vent when pressure reaches vent pressure					

Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR DRESDEN AND QUAD CITIES 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered[3]	Max Core Temp (°F)	HCTL[2] (160°F)	Comments
Case QC4A4	• Same as QC4A1 except pre-uprate power of 2511 MWt		3.4 min	Normal	13.8 min	Peak RPV pressure of 1630 psig ED at 13.8 min Peak pool temperature of 199°F
Case QC4A5	• Same as QC4A2 except pre-uprate power of 2511 MWt		17 min	Normal	9.5 min	Peak RPV pressure of 1230 psig ED at 9.5 min Peak pool temperature of 225°F
Case QC4A6	• Same as QC4A3 except pre-uprate power of 2511 MWt		25.4 min	Normal	9.1 min	Peak RPV pressure of 1230 psig ED at 9.1 min Peak pool temperature of 240°F

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Table 8-1

SUMMARY OF THERMAL-HYDRAULIC RUNS FOR DRESDEN AND QUAD CITIES 17% POWER UPRATE

Case ID	T-H Run Description	Purpose	Core Uncovered[3]	Max Core Temp (°F)	HCTL[2] (160°F)	Comments
Case QC4A7	- Same as QC4A1 except HCTL assumed at 190°F	- Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided(7)	2.6 min	Normal	N/A	Peak RPV pressure of 1870 psig No ED Peak pool temperature of 185°F
Case QC4A8	- Same as QC4A7 except pre-uprate power of 2511 MWt	- Verify time available for actions to initiate early SBLC and control RPV water level such that ED on HCTL is avoided(7)	3.2 min	Normal	N/A	Peak RPV pressure of 1630 psig No ED Peak pool temperature of 187°F

Notes to Table 8-1

(1) MSCWLL in the QCNPS general abnormal procedures (DNPS emergency operating procedures) is approximately -164"; however, the fuel zone water level instruments read high for these hot pressurized cases by 30" to 60". Therefore, ED can be anticipated to be called for at -134" to -104". Used -134" in the MAAP calculation as the most conservative representation.

(2) HCTL of 160°F based on a pool level of 14 ft at normal RPV operating pressure.

(3) Core uncovered when collapsed downcomer level drops below TAF (-142").

(4) Given that 1 ERV for ED results in core melt for Case QC1A2, the PRA conservatively assumes that 2 ERVs are required for the ED success criteria for the EPU configuration.

(5) For Case QC1A2, the time to core uncovery is 40 minutes. If 2 ERVs are credited for ED, the RPV is assumed to depressurize in sufficient time to allow low pressure injection and prevent core melt. The human reliability analysis (HRA) conservatively used a time estimate of 31 minutes for RPV depressurization. Case QC1A2 confirms that 31 minutes is still conservative.

(6) It would be more appropriate if Case QC4A1 used the number of valves available that is consistent with the ATWS success criteria. However, the purpose of this MAAP calculation is not to confirm the RPV overpressure success criteria. MAAP is not an accurate tool to use for calculating peak RPV pressure. The ATWS RPV overpressure success criteria is based on ODYN calculations and engineering judgement. Assuming that all SVs/ERVs are available should not significantly impact the results of the MAAP calculation (e.g., containment temperature).

(7) Case QC4A1 shows that the HCTL is reached at 15 minutes when the HCTL is conservatively set at 160°F. Subsequently, Case QC1A7 was developed to increase the HCTL to 190°F. The 190°F represents the HCTL if the operators manually depressurized to follow the HCTL curve. For Case QC1A7, the HCTL is not reached and confirms that the early SBLC initiation timing is adequate for the EPU configuration.

(8) The results of Case QC4A3 show that SBLC injection at 20 minutes results in a peak suppression pool temperature of 280°F. This is greater than the ATWS containment failure criteria of 260°F in the pool. The PRA conservatively assumes that SBLC must be initiated within 16 minutes to maintain pool temperature below 260°F and prevent containment failure.

Attachment
Additional Risk Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Question

Based on the recent QCNPS inspection report 2001-05, the staff has questions on how the licensee assures that the plants PSA models and associated data adequately reflect the plants current operating conditions, configurations, and practices.

9.1. Please describe how the plants assure that the system/equipment performance criteria as part of the maintenance rule implementation and the assumptions, data, and equipment unavailabilities (e.g., maintenance/testing, demand failure rates, etc.) used in the plants PSA are consistent with one another. Also include how the methodology implemented by the plants for establishing or revising performance criteria is consistent with Regulatory Guide 1.160, which indicates that the number of maintenance preventable functional failures allowed per evaluation period should be consistent with the assumptions of the PSA.

9.2. Does the PSA used in support of the extended power uprate also reflect, and is it consistent with, the current maintenance rule performance criteria? Please explain any differences between the performance criteria and the pre- and post-uprate PSA models and associated data.

9.3. Station procedures recommend updating the PSA every two years. Please state when the PSA models and the data were last updated, describe the major changes that have occurred since the last update, and discuss the potential impact of these changes on the PSA models and data, including consideration of the extended power uprate plant conditions.

9.4. The recent inspection findings indicate that there has been an increase in on-line maintenance activities, which is a programmatic change. This programmatic change, which may make past operating experience invalid in establishing maintenance unavailabilities, should be reflected in the PSA. How have the plants reflected this programmatic change in the PSA models for determining the unavailabilities of systems and equipment; specifically in determining the equipment maintenance unavailabilities? In addition, how has this change been reflected in the on-line risk monitoring tool used by the licensee to meet the maintenance rule a(4) criteria and how does this programmatic change affect other operating modes such as shutdown operations?

Response

9.1. Exelon Generation Company (EGC) assures the NRC Maintenance Rule reliability performance criteria (RPC) is consistent with the assumptions found in the PRA through the use of EPRI methodology. This methodology is described in the following EPRI documents:

- Monitoring Reliability for the Maintenance Rule, EPRI Technical Bulletin 96-11-01, November 1996
- Monitoring Reliability for the Maintenance Rule - Failures to Run, EPRI Technical Bulletin 97-3-01, March 1997

The methods use a statistical basis to determine when a failure rate experienced in the plant is significantly outside what would be expected based on the failure rate used in the PSA.

The recommended RPC is provided to the Maintenance Rule Program manager. In some cases, the system engineer, through the Maintenance Rule Program manager may request a higher RPC, in which case, a PRA sensitivity study is performed. This sensitivity study is performed in conjunction with setting the availability performance criteria (APC) as described below.

For APC, a sensitivity study is used to evaluate the risk impact of all of the performance criteria. Proposed APC values are obtained from system engineering. These proposed APC's along with RPC's (if any) that are set above the recommended value obtained using the EPRI methodology are converted to probabilities and input to the PRA. The PRA model is exercised to determine the resulting risk of core damage if all equipment were actually at their RPC and APC limits.

The APC and RPC are considered consistent with the PRA model if the quantitative screening criteria for permanent risk increases specified in the EPRI PSA Applications Guide are met.

The NRC Maintenance Rule inspection reports for the QCNPS Follow-up Inspection, LaSalle Baseline Inspection, and Braidwood Baseline Inspection indicate regulatory review and acceptance of this methodology. This methodology ensures that these RPC and APC are consistent with failure probabilities assumed in the PRA.

9.2 The PRA used in support of the EPU is consistent with the PRA used to support the NRC Maintenance Rule performance criteria as explained above. The NRC Maintenance Rule does not require that PSA models reflect the performance criteria. The NRC Maintenance Rule guidance is that the performance criteria are to be consistent with the PSA. The answer to Question 9.1, above, describes the analysis to show that the performance criteria are consistent with the base PSA. A similar analysis has not been performed for the PSA used for EPU, but given the small impacts of EPU on PRA parameters, EPU will have negligible impact on Maintenance Rule performance criteria. It should be noted that maintenance rule criteria will be reviewed following the next update.

9.3 Procedure ER-AA-600, Revision 2 (as well as previous revisions of ER-AA-600) recommends a 2 year update period, with completion permitted within 3 years. EPU risk assessments and the NRC Maintenance Rule performance criteria are based on the latest model revisions, which were completed in 1999. The 1999 models include updated equipment performance data for selected systems. All values used in the updates were reviewed for consistency with generic data. EGC risk management processes provide for ongoing review of plant design changes, procedure changes, and formal calculations, to ensure that PRA personnel are aware of actual and pending changes to the plant. Plant changes with potential impact on the PRA are recorded in a database called the Update Requirements Evaluation (URE) database, along with an assessment of whether immediate model change is required. For DNPS, there are approximately 175 entries in the URE database. For QCNPS, there are approximately 150. In no case was it concluded that an immediate model change is required. No URE issues to date, including plant changes, have been identified as having a major impact on the PRA requiring an immediate change.

9.4 Maintenance practices that have been introduced in recent years are reflected in the PSA models to the extent that data updates have captured these changes. Selected system unavailability basic events were updated in the 1999 update. If key systems are being made unavailable over significantly longer period of times than estimated, overall risk would trend significantly higher than the baseline risk. Such trends would be identified through the following process.

The plant engineers trend overall risk as part of the Maintenance Rule Program. In 2000, station engineers began quarterly evaluations of the 12 month rolling average CDF. Risk increases or decreases with respect to the base CDF are evaluated against the quantitative screening criteria for permanent risk increases as specified in the EPRI PSA Applications Guide (the guide recommends also applying these criteria to risk decreases). To date, the risk increases or decreases for either the periodic assessment period or the 12 month rolling average period have been in the "non-risk-significant" region specified by the EPRI PSA Applications Guide. These results indicate that the PRA model adequately reflects the current maintenance practices.

A 2-year rolling average data is currently available for Maintenance Rule equipment. EGC plans to utilize, for risk-significant equipment, the latest unavailability data from the Maintenance Rule database when a 3-year update is performed in 2002.

The online maintenance tool uses the "zero maintenance" PRA model, and, therefore, is unaffected by changes in the amount of hours unavailable from online maintenance. That is, online risk calculations reflect only the actual equipment out-of-service at the time of maintenance. Shutdown risk is assessed on an ongoing basis during outages using the deterministic Outage Risk Assessment and Management (ORAM) model. These models are based on defense-in-depth for key shutdown safety functions and are not affected by equipment unavailability values in the PRA model. Regardless, increased on-line maintenance reduces the need for equipment out-of-service during maintenance and refueling outages, thus reducing risk of those outages.

Question

12. What is the impact of the extended power uprate on other modes of operations; specifically shutdown operations? Please describe the impacts on these operations and provide an estimate of the impact on shutdown risk (i.e., CDF and LERF).

Response

QCNPS and DNPS

The CDF and LERF changes due to EPU have been evaluated qualitatively using the insights derived from the shutdown risk management tool used for QCNPS and DNPS and the insights gained in the application of a quantitative shutdown risk model to both sites.

The conclusion from these insights are that the changes in CDF and LERF due to EPU are negligible compared with the shutdown risk levels that are present in the pre-EPU case. Some of the insights which support this evaluation are discussed below.

The functional impacts of the EPU on shutdown risk are similar to the impacts on the at-power Level 1 PRA with the exception that reactivity additions have a different nature in the shutdown condition compared with the at-power condition.

The risk contributors include the following:
- loss of shutdown cooling
- RPV water makeup/injection failures
- Reactivity control failures

The first two functional challenges are similar in nature to the at-power risk assessment. The reactivity control functional impact at shutdown is related to mis-loaded fuel or mis-located fuel, as opposed to failure to scram issues for the at-power evaluation. The shutdown reactivity control issues are not a function of EPU and therefore their contribution to changes in CDF or LERF is assessed as zero.

The other areas of review for the shutdown risk evaluation included the following:
- Initiating Events
- Success Criteria
- Human Reliability Analysis

The following qualitative discussion applies to the shutdown conditions of Hot Shutdown (Mode 3), Cold Shutdown (Mode 4), and Refueling (Mode 5). The EPU risk impact during the transitional periods such as at-power (Mode 1) to Hot Shutdown and Startup (Mode 2) to at-power are subsumed by the at-power Level 1 PRA.

Important initiating events for shutdown include RPV draindown and loss of shutdown cooling, however, no new initiating events or increased potential for initiating events during shutdown (e.g., loss of DHR train) have been identified based on the EPU configuration. The at-power change which leads to a possible increase in the turbine trip initiating event frequency due to the need to operate the installed spare feedwater and condensate/condensate booster pumps (see response to Question 3) does not apply during shutdown conditions because the turbine has been already tripped.

The impact of the EPU on the success criteria during shutdown is similar to the Level 1 PRA. The increased power level decreases the time to boildown. However, because the reactor is already shutdown, the boildown times are relatively long compared to the at-power PRA. The boildown time is approximately 1 hour at 2 hours after shutdown (e.g., time of Hot Shutdown) and approximately 2-4 hours at 12-24 hours after shutdown (e.g., time of Cold Shutdown). The changes in the boildown time when comparing the pre-EPU cases with the EPU cases are small fractions of the total boildown time. These small changes in timing have a negligible effect on the calculated HEPs, which are found to be dominated by the Cause Based methodology inputs, and not the Time Reliability Correlation contribution.

The increased decay heat loads associated with the EPU impacts the time when low capacity DHR systems such as fuel pool cooling (FPC) and reactor water cleanup (RWCU) can be considered successful alternate DHR systems. The EPU condition delays the time after shutdown when FPC or RWCU may be used as an alternative to shutdown cooling (SDC). However, shutdown risk is dominated during the early time frame soon after shutdown when the decay heat level is high and FPC and RWCU would not be viable DHR systems for either pre-EPU or EPU conditions. QCNPS and DNPS assess the time in each outage when various DHR systems are viable. The RWCU and FPC systems would not be included in the defense-in-depth evaluation until the EPU decay heat level was sufficiently low for these systems to be successful. Therefore, the impact of the EPU on the FPC and RWCU success criteria has a negligible risk impact.

It is recognized in the shutdown risk quantifications that the SDC equipment is operating continuously for a significant portion of the outage. Therefore, for the post-EPU case, SDC would be required to run for a longer time than in the pre-EPU case before other systems with lower heat removal capacity are adequate for decay heat removal. These generally are very low risk periods during the outage. Therefore, for those low risk situations when FPC or RWCU could provide a backup in the pre-EPU case, they would become marginal in the post-EPU case for some short period of time. The time differential between the pre- and post-EPU conditions when FPC and RWCU may not be adequate alone as decay heat removal methods, is approximately 12 days in the time frame from 26 to 38 days following a shutdown based on conservative assumptions (e.g., no decay heat loss to structures or the environment). Because the shutdown risk profile is dominated by the risk at early times in the outage (i.e., 0 to 10 days), increasing the time when shutdown cooling is the only adequate decay heat removal system (during which the risk is low due to low decay heat) has a minor impact on the overall shutdown risk. With QCNPS and DNPS outages lasting less than 20 days, this change in success criteria has no impact on the integrated shutdown risk.

Other success criteria are marginally impacted by the EPU. The EPU has a minor impact on shutdown RPV inventory makeup requirements because of the low makeup requirements associated with the low decay heat level. The heat load to the suppression pool is also lower because of the low decay heat level such that the margins for suppression pool cooling capacity are adequate for the EPU condition.

The EPU impact on the success criteria for blowdown loads, RPV overpressure margin, and SRV actuation is estimated to be minor because of the low RPV pressure and low decay heat level during shutdown.

Similar to the at-power Level 1 PRA, the decreased boildown time decreases the time available for operator actions. The significant, time critical operator actions impacted in the at-power Level 1 PRA are related to RPV depressurization, SBLC injection, and SBLC level control. These operator actions do not directly apply to shutdown conditions because the RPV is at low pressure and the reactor is subcritical.

The risk significant operator actions during shutdown conditions include recovering a failed DHR system or initiating alternate DHR systems. However, the longer boildown times during shutdown results in the EPU having a minor impact on the shutdown HEPs associated with recovering or initiating DHR systems because the available time is relatively long and the HEPs are dominated by the Cause Based HRA performance shaping factors.

Based on a review of the potential impacts on initiating events, success criteria, and HRA, the EPU configuration will have a minor impact on shutdown risk.

Any quantitative impact on the EPU on shutdown risk is performed using the ORAM software. ORAM evaluates the planned plant configuration including systems available, RPV water level, RPV and containment status, and decay heat level (for calculating time to boil or time to uncover fuel). ORAM evaluates the planned outage schedule to ensure that adequate defense in depth is maintained throughout the outage. With respect to the EPU, based on the increased decay heat level, ORAM will be able to identify how much longer SDC needs to operate (e.g., 12 days longer) before alternate DHR systems (e.g., FPC and RWCU) could be placed in service.

Question

13. The allowable values for main steam isolation flow are raised variously as 120%/125% (DNPS Unit 2); 120%/140% (DNPS Unit 3); 138%/254.3 psid (QCNPS). The stated bases in NEDC-32424P-A is to keep the same basis (expressed as a percentage of steam flow) to assure that reactor trip avoidance is maintained. Thus, the setpoints will have the effect of significantly increasing the maximum size of steam line breaks that will go unisolated due to the increased steam flow under extended power uprate conditions. What analyses have been performed for the additional impact of this range of steam line breaks (e.g., on CDF or on HELB analyses)? How does this condition impact the accident progression for an unisolated main steam line break (e.g., how much quicker to core damage)?

Response

QCNPS and DNPS

Any steam line break large enough to depressurize the main steam line will result in an isolation signal on low steam line pressure. Breaks passing from 120%-140% flow are therefore still automatically isolated after EPU, even though they do not result in reaching the high flow setpoint.

There is a narrow window of main steam line breaks that could occur and not cause a high steam flow isolation signal. The setpoint changes do not significantly increase the maximum size of steamline breaks that could not receive a high steam flow logic isolation signal. The maximum change in break size that would not trigger the high steam flow logic for MSIV isolation is 3.6 inches in diameter of a break. The DNPS Unit 2 change in size is 1.2 inches in diameter. These are not considered as "significantly increasing" the maximum size of the steam line breaks that will go unisolated due to increased steam flow under EPU conditions. For example, a catastrophic break would clearly cause an isolation signal due to high steam flow and be unaffected by the small change in setpoint. In addition, the MSIVs are also isolated by high temperature sensors that would initiate an isolation given a steam break in the steam lines inside the steam tunnel for a large spectrum of steam line breaks. Further, low steam line pressure and low RPV water level logic also

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introduce additional MSIV isolation signals that provide diverse isolation capability.

High Energy Line Break (HELB)
The HELB evaluation is the subject of PUSAR Section 10.1.1.1. The results show no impact on the PRA.

PRA
The PRA characterizes the main steam line break as follows:

- The pipe failure frequency is characterized by a rupture frequency with a flow rate greater than 100 gpm equivalent.
- The effect of the break is characterized as the maximum break size.
- The failure to isolate is assessed to include the CCF of the isolation valves (where applicable) or a single valve when the break is inside the MSIV. The logic failure probability evaluation includes only the high temperature logic to initiate the isolation, not the high steam flow logic.

The failure to successfully isolate the main steam lines given a break is composed of the following failure modes:

- Logic failure that prevents the automatic signal to close the MSIVs
- Operator failure to back up the logic failure (assumed to be 1.0 failure probability in this analysis)
- Valves fail to close when signaled due to either valve fault or induced failure

The failure mode of interest in the RAI question requires failure of the following logic to prevent an isolation signal from reaching the MSIVs:

- Failure of the high temperature steam line break logic
- Failure of the high steam flow logic
- Failure of the low RPV water level logic (Level 2)
- Failure of the low RPV pressure logic

The logic will be effective over the spectrum of breaks that can also cause significant failures of equipment outside containment. Considering all the possible logic to cause MSIV closure on a steam line break, explicit modeling of the steam line break logic was not required because the core damage sequences were dominated by the valve failure to close probability.

Therefore, the change in the steam flow setpoint that would slightly increase the steam line break size that would not be isolated by high steam flow logic has no impact on the calculated CDF associated with this break outside containment (BOC) quantification.

QCNPS
Based on the QCNPS 1999 PRA results, the main steam BOC contribution to CDF is as follows:

CDF ($BOC_{Mainsteam}$) = 2.0E-11/yr

DNPS
The same approach was used for DNPS except the calculated CDF is different for DNPS due to the use of plant-specific data. Based on the DNPS 1999 PRA results, the main steam BOC contribution to CDF is as follows:

CDF ($BOC_{Mainsteam}$) = 1.5E-10/yr

Summary
No change in risk was calculated for QCNPS or DNPS because the change in isolation actuation failure probability was assessed as negligible. The change in risk could be estimated by assuming that one half the break frequency would not initiate a high flow isolation trip. This leaves the low steam line pressure trip, the low RPV water level trip and the high steam tunnel temperature logic to provide break detection and MSIV isolation. The failure probability of the actuation logic can be estimated for the two cases as follows:

Pre-EPU: P(logic)= 2E-3 x 2E-3 x 2E-3 x 2E-3 = 1.6E-11

Post-EPU: P(logic)= 2E-3 x 2E-3 x 2E-3 x 0.5 = 4E-9

The change in the logic failure probability is delta P(logic) = 3.98E-9

This causes a change in the initiating event frequency and CDF of

(3.98E-9/2E-3) = 2E-6 = 0.0002%

where, 2E-3 is the value for random failure of an MSIV to isolate credited in the base PRA model. The value 3.98E-9 represents the additional isolation failure probability (post EPU) over the base value of 2E-3. A ratio of the additional isolation failure probability to the base isolation failure provides an estimate of the small potential increase in CDF.

Time to Core Damage
The time to core damage has been evaluated for the large break LOCA event outside containment in the main steam line with no RPV injection and no MSIV isolation. The following summarizes the results of the comparison:

Large Break LOCA in Main Steam Line

Condition	Time to Core Damage
Pre-EPU	21 min

Post-EPU	18 min

No operator actions are credited for accident mitigation during this time period.

REFERENCES

1. Idaho National Engineering Laboratory, "Common Cause Failure Data Collection and Analysis System," Draft INEL-94/0064, December 1995.

2. F.M. Marshall/INEEL, D.M. Rasmussen/NRC, A. Mosleh/University of Maryland, "Common-Cause Failure Parameter Estimations," NUREG/CR-5497, October 1998.

3. "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," Final Summary Report, NUREG-1150, Vol. 1, December 1990.

4. "An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events," NUREG/CR-6595, November 1997.

5. "Anticipated Transients without Scram for Light Water Reactors," NUREG-0460, April 1978.

6. "Reliability Study, General Electric Reactor Protective System, 1984-1995," NUREG/CR-5500, Volume 3, February 1999.

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RS-01-167

August 14, 2001

U. S. Nuclear Regulatory Commission
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Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

References: (1) Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

(2) Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 7, 2001

(3) Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 13, 2001

In Reference 1, Commonwealth Edison (ComEd) Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications (TS) for Dresden Nuclear Power Station, Units 2 and 3, and Quad Cities Nuclear Power Station, Units 1 and 2, to allow operation at uprated power levels. In telephone conference calls on July 3, 2001, and July 17, 2001, between representatives of EGC and Mr. L. W. Rossbach and other members of the NRC, the NRC requested additional information regarding these proposed changes. The first portion of this information was provided in References 2 and 3. The Attachment to this letter provides the remainder of the requested information.

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Should you have any questions related to this letter, please contact Mr. Allan R. Haeger at (630) 657-2807.

Respectfully,

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Attachments:

Affidavit
Attachment: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation

cc:
Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station
NRC Senior Resident Inspector – Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

bcc Dresden Unit 2/3 Project Manager - NRR
Quad Cities Project Manager - NRR
Manager of Energy Practice - Winston & Strawn
Director – Licensing, Mid-West Regional Operating Group
Manager – Licensing, Dresden and Quad Cities Station
Site Vice President – Dresden Station
Site Vice President – Quad Cities Station
Regulatory Assurance Manager – Dresden Station
Regulatory Assurance Manager – Quad Cities Station
W. Leech – MidAmerican Energy Company
D. Tubbs – MidAmerican Energy Company
Document Control Desk Licensing (Hard Copy)
Document Control Desk Licensing (Electronic Copy)

STATE OF ILLINOIS)

COUNTY OF DUPAGE)

IN THE MATTER OF)

EXELON GENERATION COMPANY, LLC) Docket Numbers

DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3) 50-237 AND 50-249

QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2) 50-254 AND 50-265

SUBJECT: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Subscribed and sworn to before me, a Notary Public in and

for the State above named, this 14th day of

August, 2001.

VICKI L FARBO
MY COMMISSION EXP. NOV. 4, 2001

Vicki L Farbo
Notary Public

Attachment
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 34, 35, 36, 37, 38, and 39. Responses to NRC Questions 1 through 33 were provided in previous submittals (References 1 and 2).

Question

34. Section 4.1.1.2 on Containment Airspace Temperature response notes that the limiting accident for drywell airspace temperature is the small steam line break. Provide the peak drywell airspace temperature and the peak drywell shell temperature for the limiting case. Include an assessment of the impact of the EPU, e.g., are changes (if any) principally due to different codes or due to the increased power. Provide additional detail if the peak drywell airspace temperature is significantly above the drywell shell temperature structural limit (i.e. more than the 10°F exceedance for the DBA-LOCA for 10 seconds).

Response

The steam line break analysis at extended power uprate (EPU) conditions was performed for four break sizes: 0.01, 0.1, 0.3 and 0.75 ft^2. The results for these break sizes are summarized as follows:

Break Size (ft^2)	Peak Drywell Airspace Temperature (°F)	Peak Drywell Shell Temperature (°F)
0.01	257.9	213.3
0.1	325.4	273.9
0.3	337.9	275.4
0.75	337.7	277.9

The steam line break analysis was also performed for the pre-EPU power using the same computer code (i.e., SHEX) as used for the EPU to assess the impact of EPU on the peak drywell airspace and shell temperature responses. The results show that the difference between the EPU and pre-EPU results is within 1°F for both peak drywell airspace and shell temperature. Peak drywell temperature occurs early in the event, before drywell spray initiation which occurs at 600 seconds, and, therefore, is relatively insensitive to the power level.

For steam line breaks, the drywell airspace temperature increases rapidly right after initiation of the break, and high airspace temperature is maintained until the drywell spray is initiated at 600 seconds into the event. For instance, for the 0.75 ft^2 steam line break, a drywell airspace temperature of approximately 330°F is reached about 30 seconds into the event, and then rises slowly to the peak temperature. However, the drywell shell temperature stays below the limit of 281°F throughout the event, as explained below.

As specified in Appendix A of NUREG-0588 (Reference 3), the Uchida heat transfer correlation was used for steam line break accidents while in the condensing mode. This mode is applicable early in the event when the steam is superheated. After the condensation mode, a natural convection heat transfer coefficient was used in the analysis, as specified in NUREG-0588. Condensation heat transfer results in a rapid heatup of the drywell shell. The shell heatup rate decreases as the shell temperature approaches the steam saturation temperature, which is around 277°F corresponding to the drywell airspace steam partial pressure of 47 psia. Once the shell temperature increases above the saturation temperature, the primary heat transfer mode becomes natural convection, which is much less efficient than condensation heat transfer. This transition occurs around 400 seconds for a 0.75 ft^2 steam line break. The shell temperature continues to increase since the airspace temperature stays around 330°F. But, the shell temperature increase in the natural convection mode is relatively small (approximately 1°F/200 seconds). Consequently, right after the drywell spray is initiated at 600 seconds into the event, the drywell shell temperature peaks at 277.9°F. Thereafter, the drywell airspace temperature decreases rapidly due to spray, and the shell temperature also decreases.

Question

35. Section 4.1.1.2 on Containment Airspace Temperature response provides the peak value of wetwell airspace and suppression pool temperatures during a DBA-LOCA. Is the DBA-LOCA the limiting DBA/transient for these parameters? If not, provide the details of the limiting accident/transient considering the effects of EPU.

Response

Review of the results for the design basis accident loss of coolant accident (DBA LOCA) and steam line breaks analyzed at EPU conditions shows that the DBA LOCA is the limiting event for the wetwell airspace and suppression pool temperatures.

Question

36. Section 4.4, "Main Control Room Atmosphere Control System" (MCRACS)

36A. Explain how the increase in heat gain to the control room as a result of EPU for both normal and emergency modes is insignificant.

36B. Part of the second paragraph reads as follows: "The effect of EPU in combination with a 24 month fuel cycle on the post-LOCA iodine loading on the control room charcoal filter was evaluated. The post-LOCA iodine releases collected on the control room intake filters following EPU was estimated using the 0-2 hr X/Q values for the entire duration of the event, assuming no deposition or holdup of iodines in the main steam lines or in the secondary containment."

Provide the reference which serves as the basis for the evaluation and its assumptions, as noted above.

36C. State the filter efficiencies, for HEPA and charcoal filters of the MCRACS, which continue to be effective under EPU conditions.

36D. State what regulatory requirements continue to be met by MCRACS performance under EPU conditions (e.g., 10 CFR 50, Appendix A, General Design Criteria 19).

36E. Provide an example of calculated total iodine loading on MCRACS charcoal filters under EPU conditions and how these results compare with the allowable limit of 2.5 mg/gm of activated carbon, identified in Regulatory Guide 1.52.

Response

36A. The increases in heat loads due to EPU do not impact the MCRACS since these increases occur outside the control room areas. EPU does not change the way in which the plant systems operate. Thus, the major control devices in the control room remain unchanged. The small electrical currents transmitted to some indicating devices in the control room increase due to higher process temperature and electrical loads. The minor associated heat load increases from these signals have an insignificant effect on the pre-EPU design margin of the MCRACS in both normal and emergency modes.

36B. During a loss of coolant accident (LOCA), iodine is released to the environment via leakage through the main steam lines (MSL), and via leakage into secondary containment, which is released to the environment via the standby gas treatment system (SGTS). The iodine loading for the control room charcoal filter is estimated by quantifying the post-LOCA iodine release via the MSL leakage pathway and the SGTS release pathway and then addressing iodine concentrations resulting from atmospheric dispersion.

The leakage entering into the secondary containment is transported to the SGTS where it is treated by filtration before being released to the environment. The SGTS effluents are then dispersed in the atmosphere and enter the control room intake and into the control room filter. Similarly, containment leakage through the main steam isolation valves (MSIVs) is transported untreated to the control room intakes.

Listed below are the major assumptions used in this evaluation.

- There is no deposition or plateout of iodine in the MSLs. This is conservative as it results in a greater inventory of iodine available for adsorption on the control room filters.
- No credit is taken for holdup of iodine in the MSL or secondary containment. This is conservative as it increases the estimated iodine releases.
- No credit is taken for radioiodine decay. This maximizes both the containment source and the inventory accumulated in the control room filter.
- The 0 to 2 hour X/Qs are used to estimate air concentrations at the control room filter inlet for the duration of the LOCA. This assumption maximizes iodine concentrations at the control room filter inlet.
- The control room intake flowrate is increased 10% over design to account for equipment variation. This maximizes the potential deposition on the control room filters.
- The control room filters are online for the entire duration of LOCA. This is conservative as it maximizes the iodine inventory on the filters.
- To maximize the control room filter inventory, 100% filter efficiency is assumed.

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The core inventory is evaluated at 2% above the EPU rated thermal power in accordance with guidance of Regulatory Guide 1.49 (Revision 1), "Power Levels of Nuclear Power Plants."

Other design input utilized in the assessment, in addition to the Technical Specifications MSIV and containment leak rates, include the following.

- The design flow of 2000 cfm through the control room filters
- The control room atmospheric dispersion factors for the 0 to 2 hour time period for releases via MSIV leakage (1.29E-3 m^3/s) and SGTS (7.00E-4 m^3/s)
- Data on the control room charcoal filters (two banks of six trays each in series, a nominal flow rate per tray of 333 cfm, and a minimum of 46 pounds of 8 X 16 mesh charcoal per tray)

The iodine loading on the control room filters for Dresden Nuclear Power Station (DNPS) and Quad Cities Nuclear Power Station (QCNPS) is calculated to be 2.15E-3 and 2.26E-3 mg of iodine per gram of charcoal, respectively. This is a small fraction of the 2.5 mg of iodine per gram of charcoal design limit identified in Regulatory Guide 1.52 (Revision 2), "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants." The control room charcoal filter efficiency is, therefore, not impacted by EPU and a 24 month fuel cycle operation at DNPS and QCNPS.

36C. The 99% filter efficiency associated with the MCRACS high-efficiency particulate air (HEPA) and charcoal filters continues to be effective under EPU conditions.

36D. Existing commitments to regulatory requirements and guidelines included in the design bases for the MCRACS are unchanged for EPU. These requirements and guidelines include 10 CFR 50, Appendix A, General Design Criterion 19, "Criterion 19 – Control room," Regulatory Guide 1.52 (Revision 2) and Standard Review Plan Section 6.4, "Control Room Habitability System."

36E. This information is provided in the response to Question 36B.

<u>Question</u>
37. Section 4.5, "Standby Gas Treatment System"

37A. Part of the second paragraph reads as follows: "Despite the increase in iodine loading as a result of EPU and 24-month fuel cycles, test work at high iodine loading supports iodine removal efficiencies in excess of 99% at 60 mg/gm". Briefly explain the test work at high iodine loadings (on SGTS charcoal filters) that supports iodine removal efficiencies in excess of 99% at 60 mg/gm of activated carbon. State filter efficiencies, for HEPA and charcoal filters of the SGTS, which continue to be effective under EPU conditions.

37B. State what regulatory requirements continue to be met by SGTS performance under EPU conditions.

37C. Part of the third paragraph reads as follows: "The amount of cooling airflow needed to limit the adsorber temperature increase due to fission product decay heating is affected by EPU. The required minimum airflow increases from 48 cfm to 74 cfm, well below the available design flow of 300 cfm." Briefly describe how the required minimum airflow increase (from 48 cfm to 74 cfm) was determined.

Response

37A. The calculated post-LOCA total stable and radioactive iodine loading on the SGTS charcoal filters, evaluated with 2 percent additional margin in accordance with Regulatory Guide 1.49 (Revision 1) and 24 month fuel cycle operation, increases from the pre-EPU value of 6.0 milligrams of iodine per gram of charcoal (mg/gm) to 11.8 mg/gm for EPU. An industry study demonstrated that removal efficiencies over 99% for elemental iodine, which comprises 91% of the evaluated inventory, can be achieved with charcoal loadings as high as 60 mg/gm, even under adverse waterlogged conditions. The inlet concentration (nearly 200 mg/m^3) was very high for these tests, compared to approximately 0.3 mg/m^3 for a typical boiling water reactor (BWR).

For organic iodine, which comprises only 4% of the evaluated inventory, an industry study demonstrated 99% removal efficiencies are achieved with loadings as high as 4.4 mg/gm. This is approximately a factor of ten higher than the evaluated organic loading of 0.47 mg/gm for EPU. Therefore, both the elemental and organic charcoal loadings for EPU conditions are well below values that yield at least 99% removal efficiency from actual testing. Thus, the increased loadings from EPU are not sufficient to invalidate the design basis iodine removal efficiency of 95%. The design basis HEPA filter efficiency of 99% for removal of particulate iodine is unaffected by the small increase in loading resulting from uprate conditions.

37B. The testing and maintenance criteria of Regulatory Guide 1.52 (Revision 2) continue to be met in accordance with plant regulatory commitments.

37C. The fission product inventory for EPU conditions is affected by the increase in thermal power and the change to 24 month cycle GE14 fuel. Conversion of the fission product inventory to thermal heat rates, combined with a heat balance assuming no heat loss through the walls of the SGTS housing, determined the required airflow to maintain system temperature below 200°F to be conservatively less than 74 scfm. With the maximum allowable operating temperature of 250°F for components and the available cooling airflow of 300 cfm, no increase in cooling airflow is required as a result of EPU.

Attachment
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Question

38. Section 6.6, "Power Dependent Heating, Ventilation, and Air Conditioning"

38A. Provide an example showing how the increase in feedwater process temperature and the increase in the recirculation pump motor horsepower are within the margins of the heating, ventilation, and air conditioning (HVAC) system cooling capacity.

38B. Provide an example showing how the ECCS pump room coolers have adequate capacity to maintain the design basis ECCS room temperature.

38C. Explain how the heat load resulting from a temperature increase of approximately 9 degrees-F in the condensate pump area is accommodated by cooling systems, such that environmental operating temperature remains within design limits.

38D. The fifth paragraph reads as follows: "Based on a review of design basis calculations and environmental qualifications design temperatures, the design of the HVAC is adequate for the EPU."

Provide a worst-case example demonstrating how based on a review of design basis calculations and environmental qualification design temperatures, the total heat load increase is within the design margin at EPU conditions. State where the comparison with evaluations at EPU conditions is documented and would be available to the staff for review upon request.

Response

38A. The HVAC system is designed for heat loads from the recirculation pumps at QCNPS and DNPS of 1,870,000 BTU/hr and 2,190,000 BTU/hr, respectively. At EPU the expected heat load from the pump motors is 1,573,840 BTU/hr for both stations, providing a margin of approximately 296,000 BTU/hr for QCNPS and approximately 616,000 BTU/hr for DNPS.

At EPU the feedwater temperature increase is 13.8°F. The associated increase in feedwater piping heat load is 10,439 BTU/hr for each unit. The feedwater piping and the recirculation pump motors are in the same space and are cooled by the same cooling system. The margin in the HVAC design for the recirculation pump motor heat load is sufficient to compensate for the increase in feedwater piping heat load.

38B. The QCNPS residual heat removal (RHR) room heat load increases from 319,798 BTU/hr to 335,800 BTU/hr due to EPU, well within the room cooler capacity of 570,000 BTU/hr.

The high pressure coolant injection (HPCI) rooms at DNPS and QCNPS are unaffected by EPU since there are no process temperature, electrical or other heat load changes that affects the pre-EPU design heat loads.

38C. The operation of the fourth condensate/booster pump, as required for EPU operation, causes an increase in the heat load in this room. Since the cooling capacity of the ventilation system is not being changed, the pre-EPU design room temperature may be exceeded during times when the outdoor air is at the design temperature, but this will not be for extended periods of time. The normal operation of the non-safety related pumps in this area is not affected, based on a review of the motor insulation ratings, which exceed the EPU temperatures.

As discussed in Reference 4, all equipment in the EQ program affected by this temperature increase has been evaluated and is acceptable.

38D. Refer to the response to Question 38C for discussion of the worst case area temperature increase during HVAC operation. In several reactor building areas, the post-LOCA temperature increase is a few degrees due to higher EPU heat loads. The secondary containment is isolated post-LOCA and the HVAC systems for the general areas do not operate. The equipment in all such areas in the EQ program has been evaluated and found acceptable, as documented in the site EQ program documentation.

Question
39. Explain significant differences in the design and operation of the Dresden and Quad Cities HVAC systems and how such differences may impact the system evaluations at EPU conditions.

Response
The EPU evaluations for the ECCS related HVAC systems were performed separately for DNPS and QCNPS. Thus, any site differences were captured in the evaluations. The principal difference in the ECCS room coolers is that DNPS does not take credit for the operation of the LPCI and Core Spray room coolers. This was discussed in Reference 1.

The other HVAC systems are similar enough for normal operations that they could be evaluated together. The evaluations determined that no changes in the operation or configuration of these systems were required for EPU, and that all of the systems continued to meet design requirements.

Attachment
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References

1. Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 7, 2001
2. Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 13, 2001
3. "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," NUREG-0588, November 1979, (Rev. 1) July 1981
4. Letter from R. M. Krich (Exelon Generation Company, LLC) to U. S. NRC, "Additional Electrical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated July 23, 2001

Exelon Nuclear

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RS-01-161

August 13, 2001

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Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

References: (1) Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

(2) Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 7, 2001

In Reference 1, Commonwealth Edison (ComEd) Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications (TS) for Dresden Nuclear Power Station, Units 2 and 3, and Quad Cities Nuclear Power Station, Units 1 and 2, to allow operation at uprated power levels. In telephone conference calls on July 3, 2001 and July 17, 2001, between representatives of EGC and Mr. L. W. Rossbach and other members of the NRC, the NRC requested additional information regarding these proposed changes. Reference 2 provided a portion of the requested information. Attachment A to this letter provides the remainder of the requested information.

Some of the information in Attachment A is proprietary information to the General Electric Company, and EGC requests that it be withheld from public disclosure in accordance with 10 CFR 2.790(a)(4), "Public Inspections, Exemptions, Requests for Withholding." This proprietary information is indicated with sidebars. Attachment B provides the

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affidavit supporting the request for withholding the proprietary information in Attachment A from public disclosure, as required by 10 CFR 2.790(b)(1). Attachment C contains a non-proprietary version of Attachment A.

Should you have any questions related to this letter, please contact Mr. Allan R. Haeger at (630) 657-2807.

Respectfully,

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Attachments:

Affidavit
Attachment A: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Proprietary version)
Attachment B: Affidavit for Withholding Portions of Attachment A from Public Disclosure
Attachment C: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Non-proprietary version)

cc:
Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station
NRC Senior Resident Inspector – Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

bcc: Dresden Unit 2/3 Project Manager - NRR
Quad Cities Project Manager - NRR
Manager of Energy Practice - Winston & Strawn
Director – Licensing, Mid-West Regional Operating Group
Manager – Licensing, Dresden and Quad Cities Station
Site Vice President – Dresden Station
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STATE OF ILLINOIS)

COUNTY OF DUPAGE)

IN THE MATTER OF)

EXELON GENERATION COMPANY, LLC) Docket Numbers

DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3) 50-237 AND 50-249

QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2) 50-254 AND 50-265

SUBJECT: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Subscribed and sworn to before me, a Notary Public in and

for the State above named, this 13th day of

August, 2001.

V Lynn Bernhagen
Notary Public

"OFFICIAL SEAL"
V. LYNN BERNHAGEN
Notary Public, State of Illinois
My Commission Exp. 05/30/2004

Attachment A
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 9, 10, 11, 13, 14, 16, 17 (Dresden Nuclear Power Station), 31, 32, and 33. Responses to NRC Questions 1 through 8, 12, 15, and 17 through 30 were provided in a previous submittal (Reference 1).

Question

9. Provide the emergency core cooling system (ECCS) pumps net positive suction head (NPSH) calculations to support the requested additional credit for overpressure. Discuss the increased need for containment overpressure for NPSH following a design basis accident. Describe the procedures or equipment in place that will allow continued cooling flow with the drywell potentially depressurized to atmospheric conditions and the suppression chamber at the most conservative pressure associated with vacuum breaker operation (limiting case either torus/drywell or torus/reactor building). Additionally, discuss the methodology for determining the requested containment overpressure, including the headloss across the ECCS suction strainers.

Response

Additional credit for containment overpressure is required because the suppression pool temperature increases at a faster rate and peaks at a higher value compared to the pre-EPU conditions during a loss of coolant accident (LOCA). Because vapor pressure increases as the suppression pool temperature increases, the net positive suction head available (NPSHa) for each ECCS pump is reduced. To offset this reduction in NPSHa, more overpressure credit is required. More overpressure is also available, since the containment and suppression pool pressures also increase at a faster rate and peak at a higher value than before EPU.

Containment Response

The design basis accident (DBA) LOCA containment response for NPSH evaluations is analyzed for two time periods: short term (before 600 seconds), and long term (after 600 seconds). The long term temperature and pressure conditions of the suppression pool are determined based on assumptions that maximize the pool temperature and minimize the overpressure, including operation of containment sprays and vacuum breakers. Specific assumptions include the following.

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

- The reactor is operating at 102% of EPU (i.e., 3016 megawatts thermal (MWt)) with an initial reactor pressure of 1005 pounds per square inch - gauge (psig). Concurrent with occurrence of the break, reactor scram occurs.

- The reactor core power includes fission energy, fuel stored energy, metal-water reaction energy and American Nuclear Society (ANS) Standard 5.1-1979 decay heat with two sigma adder for fuel applicable to GE14 with 24 month fuel cycle.

- The initial suppression pool water volume corresponds to the low water level (LWL) to maximize the suppression pool temperature response.

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- Containment cooling is achieved by operating one low pressure coolant injection (LPCI)/ containment cooling (CC) loop at 600 seconds in the containment spray mode (drywell and wetwell sprays). This minimizes the containment pressure response, since cold water sprays will bring down the pressure.

The short term conditions are based on similar assumptions, with the following exceptions.

- There is a single failure of the loop selection logic. Consequently, the flow from all four LPCI pumps goes into the broken recirculation loop and subsequently discharges into the drywell directly. The maximum runout flow rate is assumed.

- Both core spray pumps are operating with the maximum flow rate.

Procedures

Existing plant emergency operating procedures include cautions concerning exceeding ECCS pump NPSH limits. The procedures also contain ECCS pump curves of pump flow versus torus pressure and temperature conditions. The same cautions and NPSH curves are included in the emergency operating procedures that control use of containment sprays. Thus, the operators have sufficient procedural direction to control both ECCS pump flow and containment pressure within limits.

Methodology and Results for DNPS

In discussions with the NRC, it was determined that the requested overpressure credit should be based on the methodology previously approved for DNPS in a 1997 license amendment regarding containment overpressure (Reference 2). This methodology followed the original design basis of one ECCS suction strainer completely blocked, with the remaining three strainers in clean condition. The head loss across the three clean strainers was assumed to be the same as the head loss for the original suction strainers, although those strainers were subsequently replaced with higher capacity strainers. Thus, the assumed headloss is slightly higher than the actual headloss expected with the new strainers. This assumption maintains consistency with the basis for approval of the Reference 2 amendment. EGC also expects that the headloss used to develop the requested overpressure will result in adequate overpressure when compared to the results of future calculations of suction strainer headloss discussed in the paragraph below.

NRC Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors," requested that licensees calculate suction strainer headloss assuming that debris from primary containment is distributed across all of the ECCS suction strainers. In accordance with this request, both DNPS and QCNPS will perform calculations of the suction strainer headloss and will submit a description of the methods and the results to the NRC for DNPS Units 2 and 3 and QCNPS Units 1 and 2.

NPSH calculations have been performed for EPU conditions with the strainer head loss assumptions described above for two short term and two long term flow conditions. The limiting short term ECCS flow case is all four LPCI pumps and both core spray pumps operating at maximum flow conditions. The limiting long term ECCS flow rate is the same as in the 1997 calculations that formed the basis of the currently approved overpressure credit. This limiting

flow rate is 19,000 gallons per minute (gpm) distributed as follows: two core spray pumps operating at 4,500 gpm each, one LPCI pump at 5,000 gpm, and two more LPCI pumps at 2,500 gpm each. This flow case is significantly more than the minimum long term flow of 9,750 gpm required to maintain adequate core and containment cooling after EPU. The minimum flow case of one core spray pump operating at 4,750 gpm and one LPCI pump operating at 5,000 gpm is the other case analyzed in the calculations.

The graphs showing the results of the ECCS NPSH calculations for the limiting short term and long term flow cases are provided in Figures 9-1 and 9-2. Core spray flow is the limiting NPSH case in the short term, and LPCI flow is limiting for NPSH in the long term. Figures 9-1 and 9-2 also show NPSH required (NPSHr) for both the old strainer and new strainer cases (e.g., one blocked, three clean). The higher head loss of the old strainers, as indicated above, is the basis for the requested overpressure.

In the short term, there is a period from approximately 290 seconds to 600 seconds during which some ECCS pump cavitation can occur, since the available NPSH is less than the required NPSH. This period is after the time at which the peak cladding temperature (PCT) has been reached at approximately 240 seconds. Prior to 290 seconds, the requested overpressure ensures that adequate NPSH is available to meet the core cooling requirements assumed in the PCT calculations. After 600 seconds, ECCS pump throttling restores adequate NPSH. Pump cavitation for the brief time from 290 seconds to 600 seconds is not of concern due to short duration of the cavitation.

The long term overpressure curves are plotted out to 200,000 seconds. From this point, NPSHa and NPSHr both vary directly as a function of the vapor pressure. The result is that both decrease in parallel fashion, maintaining a margin between available and required NPSH. The use of the described assumptions result in a need for overpressure credit as follows.

Period	Requested Credit (psi)
0 – 290 sec	9.5
290 - 5,000 sec	4.8
5,000 – 30,000 sec	6.6
30,001 - 40,000 sec	6.0
40,001 - 45,500 sec	5.4
45,501 - 52,500 sec	4.9
52,501 - 60,500 sec	4.4
60,501 - 70,000 sec	3.8
70,001 - 84,000 sec	3.2
84,001 - 104,000 sec	2.5
104,001 - 136,000 sec	1.8
136,001 sec – accident end	1.1

A revised proposed containment overpressure for DNPS Unit 3 will be addressed in a future submittal and will use the results of the suction strainer headloss calculations in accordance with NRC Bulletin 96-03 discussed above.

QCNPS

The overpressure credit requested for QCNPS will be addressed in a future submittal, which will use the results of ECCS suction strainer headloss calculations in accordance with NRC Bulletin 96-03 discussed above. These will be performed in support of both the Reference 3 proposed changes and the changes that were proposed in Reference 4 and discussed in the NRC response noted in Reference 5.

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Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

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Figure 9-1
DNPS Short Term Core Spray NPSH

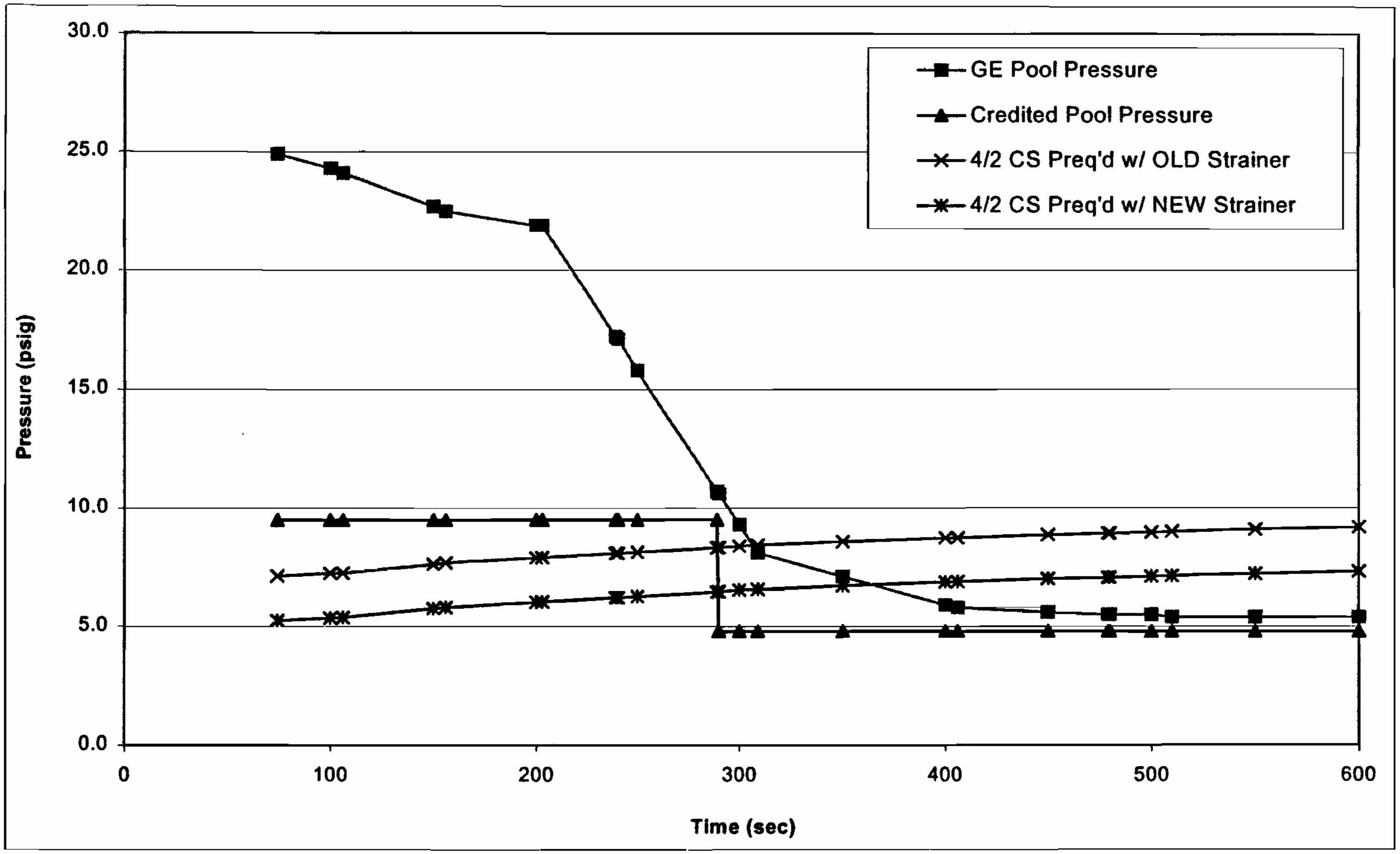
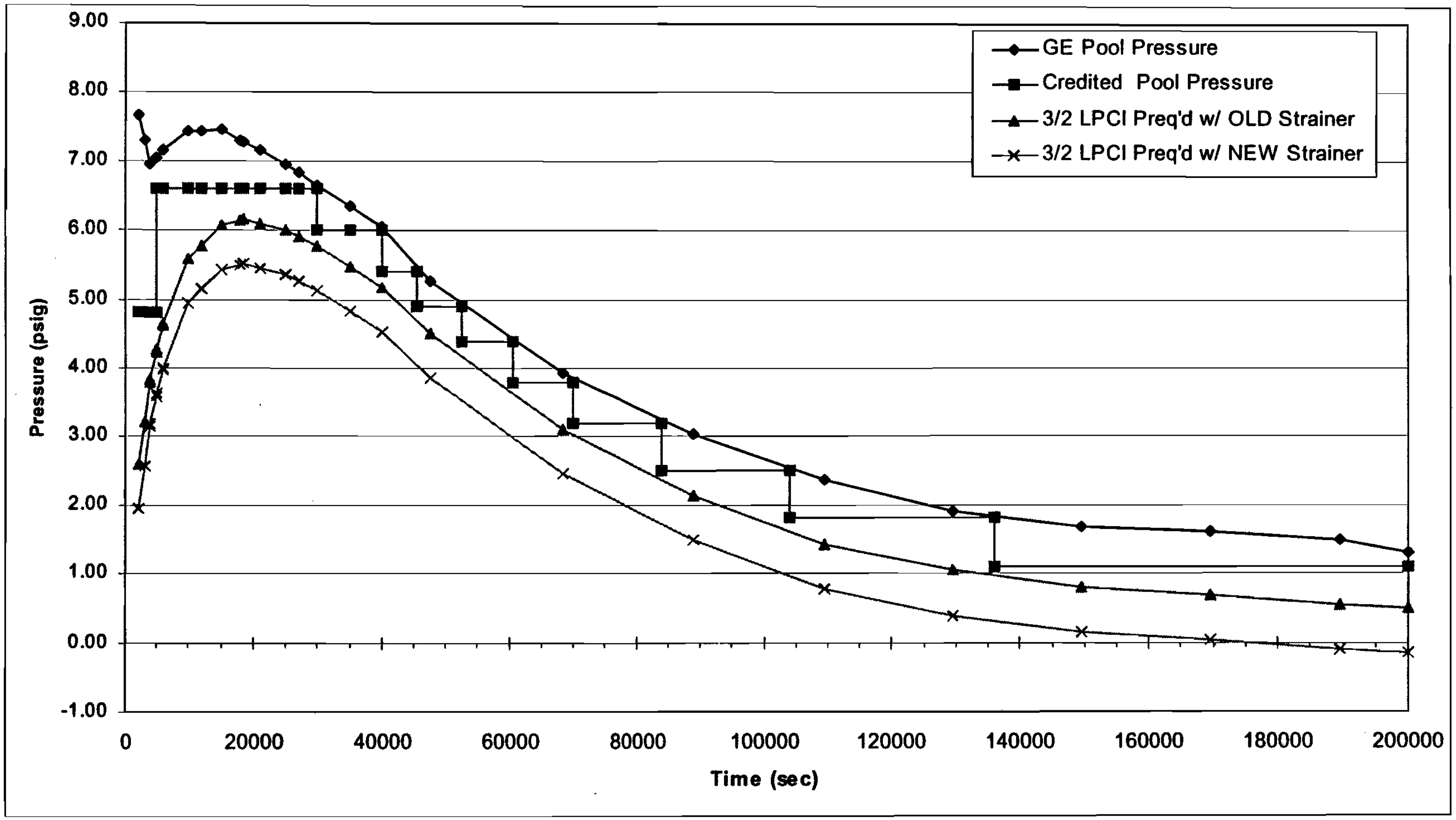


Figure 9-2
DNPS Long Term LPCI NPSH



Question

10. ELTR2 section 4.1.8.5 notes that the higher vapor pressure associated with increased suppression pool temperatures will reduce the NPSH available to the RHR and LPCS pumps and as a result the adequacy of the RHR and LPCS pumps will be evaluated at these increased temperature conditions. Were alternatives other than increased credit for overpressure considered, such as other means to enhance suction pressure, pump replacement or modification?

Response

The significant factors that determine the NPSHa for the ECCS pumps are as follows.

- The relative position and configuration of the associated piping and equipment, which controls suction elevation head and pressure flow losses
- Torus water temperature, which controls vapor pressure
- Torus overpressure, which contributes to suction pressure
- Pump flow rate, which relates to suction pressure losses
- Pump replacement

As discussed in Question 9, minimum pump flow, maximum water temperature and minimum overpressure were used in the NPSHr evaluation.

Changes to piping and equipment configuration and type were not considered as viable alternatives. To improve NPSHa, changes such as suction piping replacement or lowering of the pumps relative to the suppression pool would be required. Such changes are very difficult, require lengthy outages, and are very expensive, and are, therefore, considered impractical.

Question

11. The application is unclear or inconsistent regarding some of the requested changes for the license condition on containment overpressure. Clarify your request for these changes as noted in comment column of the following tables for Dresden and Quad Cities;

Dresden Containment Overpressure Credit (psi)

Time (seconds)	*Current license condition*	*Requested condition*	*NEDC-32962P Safety Analyses Report*	*Comment*
0-240	*9.5*			
0-290		*9.5*	*9.5*	
240-480	*2.9*			
290-5000		*4.8*	*4.8*	

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Dresden Containment Overpressure Credit (psi)

480-6000	*1.9*			
5000-30000		*~~4.25~~ 5.2*	*~~5.3~~ 5.2*	*Clarify - April 13, 2001 submittal supplement revised to 5.2 psi - however difference column remains 0.8 psi*
6000-end	*2.5*			
30000-end		*NA*	*From 30000 seconds to the end of the accident, the available pressure and require pressure decrease in parallel fashion. Minimum margin between available pressure and required pressure during this period is 2.4 psi.*	*Was this an omission or is no credit being requested? If no credit explain how long term NPSH availability has been achieved; considering the previous need of 2.5 psi and proposed need for 5.2 psi at 5000-30000 seconds.*

Quad Cities Containment Overpressure Credit (psi)

Time (seconds)	*Current amendment request*	*EPU Requested condition*	*NEDC-32961P Safety Analyses Report*	*Comment*
0-210	*8.0*			
0-290		*9.5*	*8*	*clarify/correct*
210-600	*2.5*			
290-5000		*4.8*	*4.8*	
600-10000	*3.0*			

Quad Cities Containment Overpressure Credit (psi)				
5000-30000		*4.25*	*6.75*	*Clarify/correct*
10000-end	*3.5*			
30000-end		*NA*	*From 30000 seconds to the end of the accident, the available pressure and require pressure decrease in parallel fashion. Minimum margin between available pressure and required pressure during this period is 1.6 psi.*	*Was this an omission or is no credit being requested? If no credit, explain how long term NPSH availability has been achieved; considering the previous need of 3.5 psi and proposed need for 4.25 (6.75) psi at 5000-30000 seconds.*

Response

The inconsistencies between the Reference 3 Power Uprate Safety Analysis Report (PUSAR) Table 4-2 and the license amendment request will be resolved in a revised PUSAR that will be submitted separately.

Question

13. *In many places, the bases for changing a Technical Specification relating to the extended power uprate increased power level is not provided. Selected parameters, such as the revised power level for applicability of the turbine stop valve and turbine control valve fast closure reactor trips (38.5% versus 45% currently) have stayed the same, as measured by thermal power, to maintain the same analyses power level. Selected other changes have been addressed as acceptable at the increased thermal power associated with the existing stated percentage of reactor thermal power (RTP). For example in several places the safety analyses report NEDC-32926P notes that the technical specification surveillance applicability threshold for the rod block monitor remains with a value of 30% RTP. In other places no basis is provided for the 17% increase in requirement resulting from the EPU. For example, TS SR 3.3.1.1.2 to Channel check APRMs above 25 (21.4)% RTP to verify the absolute difference is less than 2 (1.7)% RTP; the feedwater system and main turbine high water level trips required to be operable above 25 (21.4)% RTP; among others. If these changes have been addressed, provide a comprehensive cross reference to the basis for all Technical Specifications which reference RTP. If not, either provide the basis for these changes or propose changes which maintain the existing thermal power for the associated Technical Specification.*

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Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Response

The following table provides a listing of all the DNPS and QCNPS TS references to % rated thermal power (RTP) that are not being proposed for change in Reference 3. The table provides either a basis for the TS value following EPU, or a reference to the PUSAR section that discusses the basis.

TS Reference	Page	RTP	Basis
Safety Limit 2.1.1 (Reactor Core SLs)	2.0-1	≤ 25%	PUSAR Section 9.1 paragraph 8
3.1.3 Condition D (Control Rod Operability)	3.1.3-3	> 10%	PUSAR Section 5.3.12
Surveillance Requirement (SR) 3.1.4.1 (Control Rod Scram Time)	3.1.4-1	40%	See Note 4
SR 3.1.4.4 (Control Rod Scram Time)	3.1.4- 2	40%	See Note 4
LCO 3.1.6 (Rod Pattern Control)	3.1.6-1	≤ 10%	PUSAR Section 5.3.12
Section 3.2 (Power Distribution Limits)	3.2.1-1 thru 3.2.4-1	≥ 25%	PUSAR Section 9.1 paragraph 8
SR 3.3.1.1.2 (APRM Gain)	3.3.1.1-4	≥ 25%	PUSAR Section 9.1 paragraph 8
SR 3.3.2.1.2 (Control Rod Block)	3.3.2.1-4	≤ 10%	PUSAR Section 5.3.12
SR 3.3.2.1.3 (Control Rod Block)	3.3.2.1-4	≤ 10%	PUSAR Section 5.3.12
SR 3.3.2.1.5 (RBM not bypassed)	3.3.2.1-5	≥ 30%	PUSAR Section 9.2.1.2, paragraph 4
SR 3.3.2.1.6 (RWM not bypassed)	3.3.2.1-5	≤ 10%	PUSAR Section 5.3.12
Table 3.3.2.1-1 Note a (RBM)	3.3.2.1-6	≥ 30%	PUSAR Section 9.2.1.2, paragraph 4
Table 3.3.2.1-1 Note b (RWM)	3.3.2.1-6	≤ 10%	PUSAR Section 5.3.12
LCO 3.3.2.2 Applicability and Action C.2 (Feedwater / Main Turbine High Level Trip)	3.3.2.2-1 3.3.2.2-2	25%	PUSAR Section 9.1 paragraph 8
SR 3.4.2.1 (Jet Pumps)	3.4.2-1	> 25%	PUSAR Section 9.1 paragraph 8
Section 3.6.2.1 (Suppression Pool Temp)	3.6.2.1-1 3.6.2.1-2	≤ 1%	See Note 1
Section 3.6.2.5.(Drywell–Suppression DP)	3.6.2.5-1	15%	See Note 2
LCO 3.6.3.1 and Action B.1 (Primary Containment O_2)	3.6.3.1-1	15%	See Note 3
LCO 3.7.7 Applicability and Condition B (Main Turbine Bypass System)	3.7.7-1	≥ 25%	PUSAR Section 9.1 paragraph 8

Notes:

1. According to the bases for Technical Specification (TS) 3.6.2.1, the 1% RTP value is approximately equal to normal system heat losses, such that the reactor is effectively shutdown. This number was based on engineering judgment and would still apply to EPU. It should be noted that the containment analyses which are used to confirm that containment pressure and temperature limits are not exceeded consider reactor thermal powers up to 102% RTP. It is therefore expected that the increase in the RTP with EPU would not result in exceeding the design basis maximum allowable values for primary containment pressure or temperature if an accident or transient event with pool heatup were to occur at 1% RTP. Therefore, the reference to a 1% RTP is retained for TS 3.6.2.1.

2. According to the bases for TS 3.6.2.5, the drywell-to-wetwell pressure difference must be controlled when the primary containment is inert. The 15% RTP value is related to the TS requirements to inert the containment within 24 hours after the reactor is greater than 15% RTP during startup and to de-inert the containment within the last 24 hours prior to reaching 15% RTP during a plant shutdown (see TS 3.6.3.1-1, "Primary Containment O_2"). As stated in the response for TS 3.6.3.1-1 in note 3 below, the current basis and applicability of the <15% RTP is valid for EPU with respect to containment inerting requirements.

3. The current basis and applicability of the <15% RTP window for relaxation of the inerting requirement during startup and shutdown is valid for EPU. As described in bases for TS 3.6.3.1, the probability of an event that generates hydrogen during these windows is low.

4. For EPU, the requirement remains unchanged at 40% RTP. This power level is not a critical value and is chosen for convenience. The 40% RTP maximum is above the low power setpoint that allows control rod drives to be withdrawn for scram testing. It also allows scram testing to be performed sufficiently early in the startup mode when the power level is low.

Question

14. Section 6.4.1.1 Safety-related loads for service water system notes that increased heat load imposed on the containment cooling water system is within the existing system capacity following the most demanding design basis event. What is the increase in the heat load for the CCSW system and what is the system capacity?

Response

The containment cooling service water (CCSW) system is used at the DNPS Units 2 and 3 to remove heat from the suppression pool. QCNPS Units 1 and 2 use the residual heat removal service water (RHRSW) system, which serves the same function as the CCSW system at DNPS.

The heat removal rate at design conditions for the DNPS Units 2 and 3 CCSW Systems is 71 MBTU/hr with 165°F suppression pool temperature and 95°F service water temperature. As the suppression pool temperature increases, the heat load (i.e., heat removal rate) will also increase and the heat load will be the maximum at the peak suppression pool temperature. For the pre-EPU power level, an analysis was performed using the same methodology as for the EPU power level. This analysis determined that, for the pre-EPU power level, the peak suppression pool temperature is determined to be 188°F for the limiting design basis event, and the heat load at this suppression pool temperature based on the design system capability is 94 MBTU/hr. At EPU conditions, using the same methodology, the peak suppression pool temperature with the same design system capability increases to 196°F for the same limiting design basis event. The maximum heat load at this peak temperature is 102 MBTU/hr. This means that the EPU results in an increase of 8 MBTU/hr in the maximum heat load for the DNPS Units 2 and 3 CCSW Systems.

The heat removal rate at design conditions for the QCNPS Units 1 and 2 RHR Systems is 66 MBTU/hr with 165°F suppression pool temperature and 95°F service water temperature. For the pre-EPU power level, an analysis was performed using the same methodology as for the EPU power level. This analysis determined that the peak suppression pool temperature is 190°F for the limiting design basis event, and that the heat load at this suppression pool temperature based on the design system capability is 90 MBTU/hr. At EPU conditions, using this same methodology, the peak suppression pool temperature with the same design system capability increases to 199°F, and the heat load at this peak temperature is 98 MBTU/hr. Thus, an increase of 8 MBTU/hr in the maximum heat load occurs for the QCNPS Units 1 and 2 RHR Systems due to EPU.

Since the CCSW and RHRSW systems maintain the suppression pool temperatures at acceptable levels, the increased heat load on these systems is acceptable.

Question

16. Section 6.4.3. The safety analyses report states that reactor building closed cooling water system heat loads do not increase significantly following EPU. Provide the pre- and post- peak EPU heat loads for the shutdown cooling heat exchanger; spent fuel pool heat exchangers; reactor recirculation pumps; the design RBBCW heat removal capability and total peak heat load post-EPU. Include consideration of the limiting single failure or no failure if this is a more limiting case. Also include an evaluation of the maximum heat removal capability of the system.

Response

The pre- and post-EPU heat loads are provided in Tables 16-1 through 16-4. Although several individual heat loads have increased as a result of EPU, the total system heat load has not increased significantly.

Single failure of a component in the RBCCW system is accommodated by a swing heat exchanger and pump shared between the two units at each site.

To maximize the heat load delivered to the RBCCW system, the system was evaluated assuming three RBCCW heat exchangers on-line with three RBCCW pumps, three shutdown cooling heat exchangers on-line for DNPS Units 2 and 3, and two fuel pool heat exchangers on-line for DNPS Units 2 and 3 and QCNPS Units 1 and 2. This is not a normal operating configuration since a full core offload is assumed with an initial reactor coolant temperature of 339°F. The following results were obtained.

DNPS Unit 2
Heat Removed by RBCCW System: 281.2 MBTU/hr
RBCCW Heat Exchanger Cold Temperature: 107.6°F
RBCCW Heat Exchanger Hot Temperature: 133.7°F

DNPS Unit 3
Heat Removed by RBCCW System: 269.6 MBTU/hr
RBCCW Heat Exchanger Cold Temperature: 107.0°F
RBCCW Heat Exchanger Hot Temperature: 132.1°F

QCNPS Units 1 & 2
Heat Removed by RBCCW System: 38.4 MBTU/hr
RBCCW Heat Exchanger Cold Temperature: 104.1°F
RBCCW Heat Exchanger Hot Temperature: 114.0°F

Since the resulting heat exchanger hot temperatures remain acceptable, the evaluation results shown above demonstrate that the RBCCW System is capable of removing the maximum EPU calculated heat loads for each of the modes of operation.

Question

17. Section 6.4.5 addresses the adequacy of the ultimate heat sink (UHS). In the event of downstream dam losses, the water trapped in the intake and discharge bay becomes the UHS for Quad Cities 1&2 and the water trapped in the intake canal becomes the UHS for Dresden 2&3. Considering the increased decay heat associated with the EPU, provide details of the analyses of the available water supply trapped in these UHSs for safe shutdown for all units; addressing conformance with Regulatory Guide 1.27. Include any revised timing of required operator actions to maintain the UHS; if any.

Response

The design basis for the DNPS and QCNPS Cities UHS was established prior to the issuance of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants." The design bases for the DNPS and QCNPS UHS are provided in UFSAR Section 9.2.5, "Ultimate Heat Sink," for each plant.

The capability of the UHS for operation at EPU conditions was evaluated within the context of the UHS design bases as stated above. The results are provided as follows.

Dresden UHS Evaluation:

Dresden takes credit for the isolation condenser to bring the reactor temperature to 212°F. For pre-EPU design basis conditions, the amount of water required by each unit to remove decay through the isolation condenser is 2.5 million gallons over a 30 day period. For operation at EPU, 30 days requirements were calculated to be 2.9 million gallons of water per unit, which is below the 6 million gallons of water available.

As a result of the slight increase in the usage of water at EPU conditions, manual actions to place portable pumps to provide make-up water from the river to the UHS would have to be performed sooner, but this is a negligible impact, given the small increase in volume required.

Question

31. The impact of the increased heat load on the spent fuel pool (SFP) cooling is information we need to be able to fully evaluate your request for an extended power uprate for DNPS Units 2 and 3 and Quad Cities Units 1 and 2. The use of the terminology "planned" and "unplanned" has been used by the staff for the review of SFP heat load changes since questions arose in the mid-1990's regarding refueling practices at Millstone Unit 1. A planned offload is the offload of fuel assemblies to the SFP for any expected (or planned) reason. An unplanned offload is the offload of fuel assemblies to the SFP due to an unforeseen condition (e.g., unexpected shutdown that includes an offload). This difference in terminology was made to ensure SFP temperature evaluations accurately reflected actual licensee practices.

Section 6.3.1 of the safety analyses report notes that the EPU increases heat load on the spent fuel pool cooling system; and discusses analysis confirming the capability of the system to maintain adequate fuel pool cooling. Table 6-2 contains design conditions which are unchanged between pre- and post-uprate except using a 24 month fuel cycle for Quad Cities Units 1 and 2. The table additionally notes that the bulk pool temperature is less than 150°F for a full core off-load, with fuel pool with maximum capacity and with shutdown cooling in fuel pool assist mode. Additional staff review of the UFSAR indicates that both DNPS and Quad Cities were using different guidelines for evaluation of SFP cooling than the current staff practice noted above. These methods include evaluations of partial core offloads (normal) and full core offloads (abnormal); and additionally allow cycle-specific analyses of offloads in lieu of the bounding analyses described in the UFSAR. It is not clear to the staff what assumptions were used to support the EPU safety analyses report.

Please submit the results of additional evaluations on the impact of the increased EPU heat load on the SFP and supporting systems. Your evaluation of the spent fuel cooling system should address both the planned and unplanned offload conditions. The staff will accept either (1) bounding or (2) cycle-specific analyses, or both can be used.

Response

The QCNPS and DNPS fuel pool cooling and cleanup system (FPCCS) evaluation includes an assessment of the impact of uprated conditions on system operation, using partial core offloads (i.e., up to approximately 42% of a full core), which are the normal condition and full core offloads, which are the abnormal condition.

The current licensing basis for these plants is described in Updated Final Safety Analysis Report (UFSAR) Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System," which states that the SFP analyses are performed with the following conditions.

- Partial core offload requires that the fuel pool temperature must remain less than 141°F at DNPS and 140°F at QCNPS, with the single failure of a cooling train.
- Full core offload requires that temperatures remain below 145°F at DNPS and 150°F at QCNPS without assuming a single failure.

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Future refueling outages at DNPS and QCNPS are planned for partial core offloads. However, in a discussion between representatives of EGC and members of the NRC regarding this topic on August 2, 2001, the NRC stated that NRC policy for power uprates was to require that licensees demonstrate the capability to accommodate a planned full-core offload with a single failure of a cooling train. Accordingly, if DNPS and QCNPS should plan for a full core offload during future refueling outages, EGC will perform an analysis of the capability of the spent fuel pool cooling system and the spent fuel pool to perform their function assuming a single failure of a cooling train.

The EPU analysis for both QCNPS and DNPS, as discussed below, was performed to bound the various cases analyzed previously in the respective UFSARs. The EPU analysis for both the normal and abnormal conditions considers that the SFP is already filled with fuel assemblies discharged from previous refueling outages (i.e., 2867 bundles) with the exception of one batch offload to be analyzed for the current cycle (i.e. 306 bundles), with room for a full core offload (i.e., 724 bundles). Also, it is assumed that all previous batches of fuel assemblies have been exposed to a 24 month fuel cycle at the power uprated condition. Additional guidelines used for evaluation of SFP cooling are discussed below.

Each of the FPCCS primary system components was evaluated. These are defined as those flow-affected components that affect system operation due to power uprate, such as heat exchangers, pumps, and filter/demineralizers.

The following methodology and acceptance criteria for the SFP temperature have been used for the power uprate evaluation.

Methodology

The decay heat load is calculated for the two bounding scenarios, "normal" condition, and "abnormal" condition, as a function of time. The SFP temperature is calculated as a function of time, considering the following major elements of heat sources and heat sinks.

- Heat load from the fuel bundles discharged from previous refueling outages
- Heat load from the fuel bundles discharged during the current refueling outage
- Cooling by the FPCCS for QCNPS; FPCCS and shutdown cooling (SDC) for DNPS
- Cooling by evaporation from the pool surface

The evaporation rates calculated do not use any forced cooling, but use only natural circulation. The calculations use evaporation of the water from the pool surface by diffusion mechanism, and natural convection of the air towards the pool surface to equalize the pressure at the pool surface.

The ANSI/ANS Standard 5.1-1979 with two sigma uncertainty methodology is used to calculate decay heat in the SFP for both QCNPS and DNPS

QCNPS Assumptions and Acceptance Criteria

SFP bulk temperature shall remain at or below 140°F for a "normal" offload into an almost full

pool. For single failure considerations, three pumps and four heat exchangers of FPCCS out of a total of four pumps and four heat exchangers are assumed to be available. Since four trains of fuel pool cooling are available at QCNPS, and since these are adequate to maintain fuel pool temperature, the failure of one pump is considered the bounding single failure. An initial fuel pool temperature of 110°F was used, which is the normal temperature when there is no refueling activity.

SFP bulk temperature shall be at or below 150°F for an "abnormal" off-load (full core) into a "full" pool that contains the batch just offloaded (i.e., 3173 bundles transferred to the spent fuel pool from previous off loads). Single failure need not be assumed, and four trains of FPCCS (four pumps, four heat exchangers) are assumed to be available.

The required makeup flow for the partial core offload is below the existing system capacity of 51 gpm for each unit. When the two SFPs are inter-tied, the makeup flow capacity doubles to 102 gpm, which is greater than the required makeup flow of 78.5 gpm.

DNPS Assumptions and Acceptance Criteria

SFP bulk temperature shall remain at or below 141°F for a "normal" off-load. An initial fuel pool temperature of 110°F was used, which is the normal temperature when there is no refueling activity.

For single failure considerations, only one train of FPCCS (one pump, two heat exchangers) out of the two pumps and two heat exchangers was assumed to be available. One of the three SDC system loops is aligned to the fuel pool in alternate decay heat removal (ADHR) mode. In ADHR mode, this train of SDC is aligned to the SFP and provides cooling to the fuel in both the SFP and the reactor vessel. ADHR mode is initiated only after a cycle specific determination of the time following reactor shutdown at which the heat removal capability of this mode is adequate. In ADHR mode, the single failure of one train of the FPCCS is considered the bounding single failure because, during refueling outages, DNPS retains the ability to line up an additional train of SDC to the fuel pool within eight hours of the loss of the operating SDC train. The management of this SDC availability is governed by DNPS shutdown safety management procedures.

SFP bulk temperature shall be at or below 150°F for an "abnormal" off-load (full core) into a "full" pool that contains the batch just offloaded (i.e., 3173 bundles transferred to the spent fuel pool from previous offloads). Single failure need not be assumed for this case, so this is accomplished with both trains of FPCCS (two pumps, two heat exchangers) and one SDC system loop in fuel pool cooling assist mode.

The required makeup flow of about 30 gpm for the partial core offload case is below the existing system capability of 54 gpm. For the full core offload case the makeup requirement is 70 gpm. There are several fire hoses that are also available to provide makeup water for the full core offload case or for the pool in the event of loss of fuel pool cooling. There are three sources for water: contaminated demineralization system, clean demineralization system and the fire protection system. Each fire hose is capable of delivering over 90 gpm. Therefore the makeup

flow is much greater than the 70 gpm water loss calculated due to EPU.

Normal Condition - Batch Offload
A heat sink temperature of 95°F is assumed to be available for cooling the FPCCS heat exchangers (including SDC heat exchanger for DNPS) and the SFP is assumed to be initially at 110°F for these conditions.

The heat load from the previous cycles is based on 2867 bundles in the SFP. These bundles are assumed to consist of ten offloads, the first offload of 113 bundles and nine subsequent offloads, each with 306 bundles. Each batch is discharged at 24 month intervals, having seen 2957 MWt (EPU condition). When added to the 306 offloaded bundles, 3173 cells are loaded for normal condition.

The fuel transfer from the RPV to the SFP is initiated at 100 hours after reactor shutdown and with fuel transfer rate of ten fuel bundles per hour. When the fuel transfer is initiated, the fuel pool gate is assumed to open, and stay open until the end of the fuel transfer. At the end of fuel transfer, the fuel pool gate is assumed to be closed, and the heat load in the RPV is assumed to be cooled by the RHR system (QCNPS) or the SDC system (DNPS). While the fuel pool gate is open, the surface area of the reactor cavity is added for additional evaporation and the water mass in the reactor cavity is also used for additional heat absorption.

With these assumptions, the SFP temperature versus time is calculated, as is the evaporative loss from the pool surface. Assuming all fuel pool cooling is lost for the above batch offload scenario, at the time of peak SFP temperature, the time to reach the boiling point and the boiloff rate is calculated. The acceptance criterion for the SFP temperature is to be at or below 140°F for QCNPS and 141°F for DNPS.

Abnormal Condition - Full Core Offload
The batch offload for normal condition is accomplished following one complete 2-year cycle. Following normal condition, the plant completes another 2-year cycle, and an "emergency" requires that the full core be offloaded into the SFP. This "emergency" scenario defines abnormal condition.

A heat sink temperature of 95°F is assumed for cooling the heat exchangers for FPCCS (and SDC heat exchanger for DNPS).

The fuel transfer from the RPV to the SFP is initiated at 100 hours after reactor shutdown and with fuel transfer rate of ten fuel bundles an hour.

The SFP temperature and the evaporative loss are calculated for this case. Then, assuming all fuel pool cooling is lost for the above core offload scenario at the time of peak SFP temperature, the time before the pool reaches the boiling point is calculated, and the boiloff rate is calculated.

The abnormal condition acceptance criterion for the SFP temperature is to be at or below 150°F.

Results
The results of evaluations on the impact of the increased EPU heat load on the SFP and supporting systems are included in Tables 33-1 and 33-2. These evaluations indicate that the current requirements for SFP temperature can be maintained under EPU conditions.

Question
31.1 Bounding Analysis - Your response for a bounding analysis should include two scenarios planned and unplanned offloads.

A)Planned Offload Calculation - Planned offload is the offload of fuel assemblies to the SFP for any expected (or planned) reason.
Analysis conditions:
1) decay heat load is from spent fuel that is "planned" to be offloaded, either full or partial core plus heat load from an SFP with all other storage locations filled
2) bulk SFP temperature must remain below 150°F
3) worst single active failure, including common cause failures (not just one train)
4) initial conditions highest ultimate heat sink temperature; fouled heat exchangers.
If the resultant temperature is above 150°F, you should perform and submit an analysis to demonstrate that the SFP structure can withstand the new high temperature for long periods of time.

B) Unplanned Offload Calculation - An unplanned offload is the offload of fuel assemblies to the SFP due to an unforeseen condition (e.g., unexpected shutdown that includes an offload).
Analysis conditions:
1) decay heat load is based on a full core offload plus refueling load that has decayed for 36 days plus heat load from an SFP with all other storage locations filled
2) bulk SFP temperature must remain below boiling
3) no single failure needs to be considered

Response
For a discussion of planned and unplanned offloads, see the response to Question 31 above.

Regarding the assumptions used for the emergency offload, the decay heat load is based on a full core offload that has been operating for a full 24 month cycle, plus a refueling load that has decayed for 24 months plus the heat load from the SFP with all other storage locations filled. This bounds the emergency offload after 36 days of operation as described below. The maximum peak decay heat load for a full core offload into the SFP (completed 173 hours after shutdown) is 37.8 MBTU/hr after 36 days of operation and 37.9 MBTU/hr after 2 years of operation.

Question
31.2 Cycle-specific Analysis - You can alternately opt to perform a calculation prior to every planned offload using the actual conditions at the time of the offload. The wait time for offload can be adjusted, as long as the time is not shorter than what is assumed for the fuel handling accident. For unplanned offload, you can either commit to performing the same calculation prior

to offload or have a bounding calculation for unplanned offloads only, using the same guidelines as in Section 31.1 B) above.
Cycle-specific analysis conditions
1) decay heat load based on actual number of fuel assemblies planned to be offloaded plus heat load from actual assemblies in the previously loaded into pool
2) use actual system conditions ultimate heat sink temperature; heat exchanger fouling
3) worse active single failure, including common cause failures (not just one train)
4) bulk SFP temperature must remain below 150°F
5) include temporary modifications, if any

Response
The calculations performed for EPU are expected to be bounding for partial core offloads. As discussed in the response to Question 31 above, if DNPS and QCNPS should plan for a full core offload during future refueling outages, EGC will perform an analysis of the capability of the spent fuel pool cooling system and the spent fuel pool to perform their function assuming a single failure of a cooling train.

The calculations performed for EPU are expected to be bounding for unplanned offloads.

Question
32. Ability to supply adequate make-up source in event of loss of SFP cooling
Considering any analyses changes, re-confirm time to boil-off is sufficient to allow mitigative actions and the make up water required is within the system capacity in case of a complete loss of cooling to the SFP. Provide time to boil-off and boil-off rate.

Response
Time to boil and boil-off rates are given in the attached Tables 31-1 and 31-2. The makeup water capability is discussed in the response to Question 31.

Question
33. Section 4.7 on post-LOCA combustible gas control notes margin changes in various parameters associated with the EPU and additional impact of GE14 fuel introduction on metal-water hydrogen production. The 5% oxygen limit is reached in 19 hours, versus 25 hours pre-EPU. The minimum stored volume of nitrogen to maintain containment atmosphere below the 5% flammability limit for seven days will be 141,000 scf following EPU. Considering the increased nitrogen storage requirement and the reduced time to reach oxygen flammability concentrations following a design basis accident, address why technical specifications should not be added for the operability and surveillance of the containment atmosphere dilution system, including nitrogen storage (Reference BWR/4 STS 3.6.3.4, in accordance with 10 CFR 50.36(c)(2)(ii) criterion 3 - A system that is part of the primary success path and which functions to mitigate a design basis accident that presents a challenge to the integrity of a fission product barrier).

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Response

The DNPS and QCNPS TS were recently revised to reflect the BWR Improved Standard Technical Specifications as noted in Reference 6. NUREG-1433, Specification 3.6.3.4, "Containment Atmosphere Dilution (CAD) System," was not included in the DNPS and QCNPS Improved Technical Specifications since the current licensing basis did not include requirements for a CAD system. In Reference 7, the NRC approved the deletion of the technical specification (TS) requirement for the primary containment nitrogen system based upon relocating these requirements to the UFSAR. The nitrogen system supports the requirements for primary containment oxygen concentration specified in TS 3.6.3.1. The nitrogen system also performs the CAD system function to maintain post-accident combustible gas concentrations within the primary containment at or below the flammability limits by purging the containment atmosphere with nitrogen. Since the NRC had previously determined that licensee controlled procedures and administrative controls were adequate to ensure nitrogen system operability, no new TS requirements associated with the EPU were deemed to be necessary. The nitrogen system continues to maintain the containment in an inerted condition as required by TS 3.6.3.1 and remain capable of purging the containment with nitrogen as necessary under accident conditions. Therefore, consistent with the current licensing basis, CAD requirements are not included in the TS for EPU.

Table 16-1
Pre-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – DNPS Unit 2 or 3

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Reactor Recirculation Pump and Motors	0.9	0.9	0.5	0.9	0.9
Fuel Pool Coolers	7.3	7.3	7.3	7.3	-
Shutdown Heat Exchanger	-	90	48.5	-	-

Post-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – DNPS Unit 2 or 3

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Reactor Recirculation Pump and Motors	1.01	1.01	0.56	1.01	1.01
Fuel Pool Coolers	13(1)	13(1)	17(2)	13(1)	-
Shutdown Heat Exchanger	-	374.1(3)	48.5	-	-

Footnotes:

(1) At 17 days, heat load is 13 x 10^6 BTU/hr

(2) For emergency, full core offload, heat load will be 39.0 x 10^6 BTU/hr. However, the shutdown heat exchanger heat load will be 0 BTU/hr. (At 6 days, heat load is 17 x 10^6 BTU/hr)

(3) For commercial reasons, it is desirable to cool down the reactor within 24 hours for a refueling outage. The ability of the RBCCW system to achieve refueling temperature (140°F) within 24 hours was evaluated as part of the EPU evaluation. For this operating mode, an initial heat transfer from the shutdown heat exchangers of 374.1 x 10^6 BTU/hr and a total system heat transfer rate of 435.78 x 10^6 BTU/hr will be required. Although the design heat transfer rate with two RBCCW heat exchangers is 156 x 10^6 BTU/hr, and the design heat transfer rate with three RBCCW heat exchangers is 234 x 10^6 BTU/hr, the required heat transfer rate of 435.78 x 10^6 BTU/hr can be achieved at service water temperatures below the design value of 95°F. There are no safety concerns associated with achieving shutdown within 24 hours, so if the service water temperature is too high or if only two RBCCW heat exchangers are used, it will simply take longer to achieve cold shutdown.

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Attachment A
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 16-2
Pre-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – QCNPS Unit 1 or 2

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Fuel Pool Coolers	8.8	8.8	8.8	8.8	-
Reactor Recirculation Pump and Motors	0.9	0.5	-	0.5	0.5

Post-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – QCNPS Unit 1 or 2

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Fuel Pool Coolers	18(1)	18(1)	45(2)	18(1)	-
Reactor Recirculation Pump and Motors	1.01	1.01	-	1.01	1.01

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Footnotes:

(1) For normal refueling, at 17 days heat load is 18 x 10^6 BTU/hr.
(2) For emergency, full core offload, heat load will be 45.0 x 10^6 BTU/hr. at 7.1 days after shutdown. (At 17 days, heat load is 35 x 10^6 BTU/hr.)

Table 16-3
Total System Heat Loads Cooled By RBCCW
DNPS Total RBCCW System Heat Loads (x 10^6 BTU/HR)

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Heat removal rate at original design conditions	156	234(3)	156	156	78
Pre-EPU heat removal rate (DNPS Unit 2)	61.04	145.87	69.65	54.87	5.4
Post-EPU heat removal rate (DNPS Unit 2(1))	66.85	435.78(2)	79.41	60.68	5.51

Footnotes:

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(1) Heat loads at DNPS Unit 2 are most conservative
(2) For commercial reasons, it is desirable to cool down the reactor within 24 hours for a refueling outage. The ability of the RBCCW system to achieve refueling temperature (140°F) within 24 hours was evaluated as part of the EPU evaluation. For this operating mode, an initial heat transfer from the shutdown heat exchangers of 374.1 x 10^6 BTU/hr and a total system heat transfer rate of 435.78 x 10^6 BTU/hr will be required. Although the design heat transfer rate with two RBCCW heat exchangers is 156 x 10^6 BTU/hr, and the design heat transfer rate with three RBCCW heat exchangers is 234 x 10^6 BTU/hr, the required heat transfer rate of 435.78 x 10^6 BTU/hr can be achieved at service water temperatures below the design value of 95°F. There are no safety concerns associated with achieving shutdown within 24 hours, so if the service water temperature is too high or if only two RBCCW heat exchangers are used, it will simply take longer to achieve cold shutdown. The heat removal rate required to reach the TS cold shutdown temperature of 212°F is within the capability of the system.
(3) The third RBCCW heat exchanger is used during cooldown, to minimize outage time for refueling.

Table 16-4
QCNPS Total RBCCW System Heat Loads (x 10^6 BTU/HR)

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Heat removal rate at original design conditions	27.64(3)	27.64(3)	41.46(1) (3)	27.64(3)	13.82(3)
Pre-EPU heat removal rate	29.64	29.24	13.89	29.24	5.30
Post-EPU heat removal rate	38.95(2)	38.95(2)	50.09(2)	38.95(2)	5.81

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Footnotes:

(1) The third RBCCW heat exchanger is used during emergency full core off-load.
(2) The heat exchangers are able to dissipate the higher heat loads without exceeding the current design basis cold RBCCW temperature of 105°F, based on a new maximum service water temperature of 90°F. The original design service water temperature from manufacturer data sheets was 95°F, but operating experience has shown that service water temperatures have never exceeded 90°F in the history of operation of QCNPS. It is concluded that with two RBCCW heat exchangers aligned to each QCNPS Unit and a maximum service water temperature of 90°F, the cold RBCCW temperature will not exceed 104°F for all operating modes except the emergency full core offload event. For the emergency full core offload event, the swing heat exchanger will need to be aligned to the unit with the emergency full core offload. All other operating parameters of the RBCCW system (flows, pressures, temperatures) will remain the same as before EPU.
(3) RBCCW heat exchanger design heat transfer values are based on manufacturer data sheets using 95°F as the inlet service water temperature. The design basis maximum service water temperature has been changed to 90°F, which results in heat transfer capability exceeding required load for all operating modes.

TABLE 31-1
QCNPS SPENT FUEL POOL DECAY HEAT LOAD PARAMETERS

SFP Case	Peak Heat Loads	Time to Boil(1) (from peak pool temperature)	Boiloff Rate at 212°F	Peak SFP Temperature with FPCCS	Remarks
Normal Condition: Batch offload of 306 bundles 100 hours after shutdown	22.3 X 10^6 BTU/hr	40 hrs	43 gpm	128°F at 157 hours after shutdown	Pool almost full (2867 cells filled) with uprate bundles. SFP contains 3173 bundles after offload. Three FPCCS pumps and four heat exchangers operating.
Abnormal Condition: batch offload of 724 bundles 100 hours after shutdown	44.3 X 10^6 BTU/hr	13.5 hours	78.5 gpm	150°F at 190 hours after shutdown	Pool almost full (3173 cells filled) with uprate bundles. SFP contains 3897 bundles after offload. Four FPCCS pumps and heat exchangers operating. Two years of operation after above batch offload. QCNPS has 102 gpm makeup water capability from two units.

(1) To 211°F

TABLE 31-2
DNPS SPENT FUEL POOL DECAY HEAT LOAD PARAMETERS

SFP Case	Peak Heat Loads	Time to Boil (from peak pool Temperature)	Boiloff Rate at 212°F	Peak SFP Temperature with FPCCS	Remarks
Normal Condition: Batch offload of 306 bundles 100 hours after shutdown	17.4×10^6 BTU/hr	29 hours	30 gpm	125°F at 146 hours after shutdown	Pool almost full (2867 cells filled) with uprate bundles. SFP contains 3173 bundles after offload. One FPCCS pump and two heat exchangers and SDC in FPC assist mode operating.
Abnormal Condition: Batch offload of 724 bundles 100 hours after shutdown	39.1×10^6 BTU/hr	8 hours	70 gpm	150°F at 183 hours after shutdown	Pool almost full (3173 cells filled) w/ uprate bundles. SFP contains 3897 bundles after offload. Two FPCCS pumps and heat exchangers operating along with one SDC at 1500 gpm. Two years of operation after above batch offload.

Attachment A
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References

1. Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 7, 2001

2. Letter from U. S. NRC to I. Johnson (Commonwealth Edison Company), "Issuance of Amendments," dated April 30, 1997

3. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

4. Letter from J. P. Dimmette, Jr. (Commonwealth Edison Company) to U.S. NRC, "Request for License Amendment Pursuant to 10 CFR 50.90 Credit for Overpressure," dated January 29, 1999

5. Letter from U. S. NRC to O. D. Kingsley (Commonwealth Edison Company), "Quad Cities – Contractor Review of Head Loss Calculations Associated with Request for License Amendment," dated September 8, 2000

6. Letter from U. S. NRC to O. D. Kingsley (Exelon Generation Company, LLC), "Issuance of Amendments", dated March 30, 2001

7. U. S. NRC, "Safety Evaluation By The Office Of Nuclear Reactor Regulation Related to Amendment No. 150 to Facility Operating License No. DPR-19, Amendment No. 145 to Facility Operating License No. DPR-25, Amendment No. 171 to Facility Operating License No. DPR-29, and Amendment No. 167 to Facility Operating License No. DPR-30, Commonwealth Edison Company and MidAmerican Energy Company," dated June 28, 1996

Attachment B
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Affidavit for Withholding Portions of Attachment A from Public Disclosure

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General Electric Company

AFFIDAVIT

I, George B. Stramback, being duly sworn, depose and state as follows:

(1) I am Project Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Attachment 1 to letter GE-DQC–EPU-01-467, *Plant Systems RAIs Package 2*, (GE Proprietary Information), dated August 7, 2001. The proprietary information is delineated by bars marked in the margin adjacent to the specific material in the Attachment 1, *GE Response to NRC Plant Systems RAIs.*

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

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c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in both paragraphs (4)a. and (4)b., above.

(5) The information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains further details regarding the GE proprietary report NEDC-32961P, *Safety Analysis Report for Quad Cities 1 & 2 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, and NEDC-32962P, *Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, which contain detailed results of analytical models, methods and processes, including computer codes, which GE has

developed, obtained NRC approval of, and applied to perform evaluations of transient and accident events in the GE Boiling Water Reactor ("BWR").

The development and approval of these system, component, and thermal hydraulic models and computer codes was achieved at a significant cost to GE, on the order of several million dollars.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GE asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GE would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

George B. Stramback, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 7th day of August 2001.

George B. Stramback
General Electric Company

Subscribed and sworn before me this 7th day of August 2001.

TERRY J. MORGAN
Commission # 1304914
Notary Public - California
Santa Clara County
My Comm. Expires May 18, 2005

Notary Public, State of California

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (non-proprietary version)

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Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 9, 10, 11, 13, 14, 16, 17 (Dresden Nuclear Power Station), 31, 32, and 33. Responses to NRC Questions 1 through 8, 12, 15, and 17 through 30 were provided in a previous submittal (Reference 1).

Question
9. Provide the emergency core cooling system (ECCS) pumps net positive suction head (NPSH) calculations to support the requested additional credit for overpressure. Discuss the increased need for containment overpressure for NPSH following a design basis accident. Describe the procedures or equipment in place that will allow continued cooling flow with the drywell potentially depressurized to atmospheric conditions and the suppression chamber at the most conservative pressure associated with vacuum breaker operation (limiting case either torus/drywell or torus/reactor building). Additionally, discuss the methodology for determining the requested containment overpressure, including the headloss across the ECCS suction strainers.

Response
Additional credit for containment overpressure is required because the suppression pool temperature increases at a faster rate and peaks at a higher value compared to the pre-EPU conditions during a loss of coolant accident (LOCA). Because vapor pressure increases as the suppression pool temperature increases, the net positive suction head available (NPSHa) for each ECCS pump is reduced. To offset this reduction in NPSHa, more overpressure credit is required. More overpressure is also available, since the containment and suppression pool pressures also increase at a faster rate and peak at a higher value than before EPU.

Containment Response
The design basis accident (DBA) LOCA containment response for NPSH evaluations is analyzed for two time periods: short term (before 600 seconds), and long term (after 600 seconds). The long term temperature and pressure conditions of the suppression pool are determined based on assumptions that maximize the pool temperature and minimize the overpressure, including operation of containment sprays and vacuum breakers. Specific assumptions include the following.

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

- The reactor is operating at 102% of EPU (i.e., 3016 megawatts thermal (MWt)) with an initial reactor pressure of 1005 pounds per square inch - gauge (psig). Concurrent with occurrence of the break, reactor scram occurs.

- The reactor core power includes fission energy, fuel stored energy, metal-water reaction energy and American Nuclear Society (ANS) Standard 5.1-1979 decay heat with two sigma adder for fuel applicable to GE14 with 24 month fuel cycle.

- The initial suppression pool water volume corresponds to the low water level (LWL) to maximize the suppression pool temperature response.

- Containment cooling is achieved by operating one low pressure coolant injection (LPCI)/ containment cooling (CC) loop at 600 seconds in the containment spray mode (drywell and wetwell sprays). This minimizes the containment pressure response, since cold water sprays will bring down the pressure.

The short term conditions are based on similar assumptions, with the following exceptions.

- There is a single failure of the loop selection logic. Consequently, the flow from all four LPCI pumps goes into the broken recirculation loop and subsequently discharges into the drywell directly. The maximum runout flow rate is assumed.
- Both core spray pumps are operating with the maximum flow rate.

Procedures

Existing plant emergency operating procedures include cautions concerning exceeding ECCS pump NPSH limits. The procedures also contain ECCS pump curves of pump flow versus torus pressure and temperature conditions. The same cautions and NPSH curves are included in the emergency operating procedures that control use of containment sprays. Thus, the operators have sufficient procedural direction to control both ECCS pump flow and containment pressure within limits.

Methodology and Results for DNPS

In discussions with the NRC, it was determined that the requested overpressure credit should be based on the methodology previously approved for DNPS in a 1997 license amendment regarding containment overpressure (Reference 2). This methodology followed the original design basis of one ECCS suction strainer completely blocked, with the remaining three strainers in clean condition. The head loss across the three clean strainers was assumed to be the same as the head loss for the original suction strainers, although those strainers were subsequently replaced with higher capacity strainers. Thus, the assumed headloss is slightly higher than the actual headloss expected with the new strainers. This assumption maintains consistency with the basis for approval of the Reference 2 amendment. EGC also expects that the headloss used to develop the requested overpressure will result in adequate overpressure when compared to the results of future calculations of suction strainer headloss discussed in the paragraph below.

NRC Bulletin 96-03, "Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling-Water Reactors," requested that licensees calculate suction strainer headloss assuming that debris from primary containment is distributed across all of the ECCS suction strainers. In accordance with this request, both DNPS and QCNPS will perform calculations of the suction strainer headloss and will submit a description of the methods and the results to the NRC for DNPS Units 2 and 3 and QCNPS Units 1 and 2.

NPSH calculations have been performed for EPU conditions with the strainer head loss assumptions described above for two short term and two long term flow conditions. The limiting short term ECCS flow case is all four LPCI pumps and both core spray pumps operating at maximum flow conditions. The limiting long term ECCS flow rate is the same as in the 1997 calculations that formed the basis of the currently approved overpressure credit. This limiting flow rate is 19,000 gallons per minute (gpm) distributed as follows: two core spray pumps operating at 4,500 gpm each, one LPCI pump at 5,000 gpm, and two more LPCI pumps at 2,500 gpm each. This flow case is significantly more than the minimum long term flow of 9,750 gpm required to maintain adequate core and containment cooling after EPU. The minimum flow case of one core spray pump operating at 4,750 gpm and one LPCI pump operating at 5,000 gpm is the other case analyzed in the calculations.

The graphs showing the results of the ECCS NPSH calculations for the limiting short term and long term flow cases are provided in Figures 9-1 and 9-2. Core spray flow is the limiting NPSH case in the short term, and LPCI flow is limiting for NPSH in the long term. Figures 9-1 and 9-2 also show NPSH required (NPSHr) for both the old strainer and new strainer cases (e.g., one blocked, three clean). The higher head loss of the old strainers, as indicated above, is the basis for the requested overpressure.

In the short term, there is a period from approximately 290 seconds to 600 seconds during which some ECCS pump cavitation can occur, since the available NPSH is less than the required NPSH. This period is after the time at which the peak cladding temperature (PCT) has been reached at approximately 240 seconds. Prior to 290 seconds, the requested overpressure ensures that adequate NPSH is available to meet the core cooling requirements assumed in the PCT calculations. After 600 seconds, ECCS pump throttling restores adequate NPSH. Pump cavitation for the brief time from 290 seconds to 600 seconds is not of concern due to short duration of the cavitation.

The long term overpressure curves are plotted out to 200,000 seconds. From this point, NPSHa and NPSHr both vary directly as a function of the vapor pressure. The result is that both decrease in parallel fashion, maintaining a margin between available and required NPSH. The use of the described assumptions result in a need for overpressure credit as follows.

Period	Requested Credit (psi)
0 – 290 sec	9.5
290 - 5,000 sec	4.8
5,000 – 30,000 sec	6.6
30,001 - 40,000 sec	6.0
40,001 - 45,500 sec	5.4
45,501 - 52,500 sec	4.9
52,501 - 60,500 sec	4.4
60,501 - 70,000 sec	3.8
70,001 - 84,000 sec	3.2
84,001 - 104,000 sec	2.5
104,001 - 136,000 sec	1.8
136,001 sec – accident end	1.1

A revised proposed containment overpressure for DNPS Unit 3 will be addressed in a future submittal and will use the results of the suction strainer headloss calculations in accordance with NRC Bulletin 96-03 discussed above.

QCNPS

The overpressure credit requested for QCNPS will be addressed in a future submittal, which will use the results of ECCS suction strainer headloss calculations in accordance with NRC Bulletin 96-03 discussed above. These will be performed in support of both the Reference 3 proposed changes and the changes that were proposed in Reference 4 and discussed in the NRC response noted in Reference 5.

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Figure 9-1
DNPS Short Term Core Spray NPSH

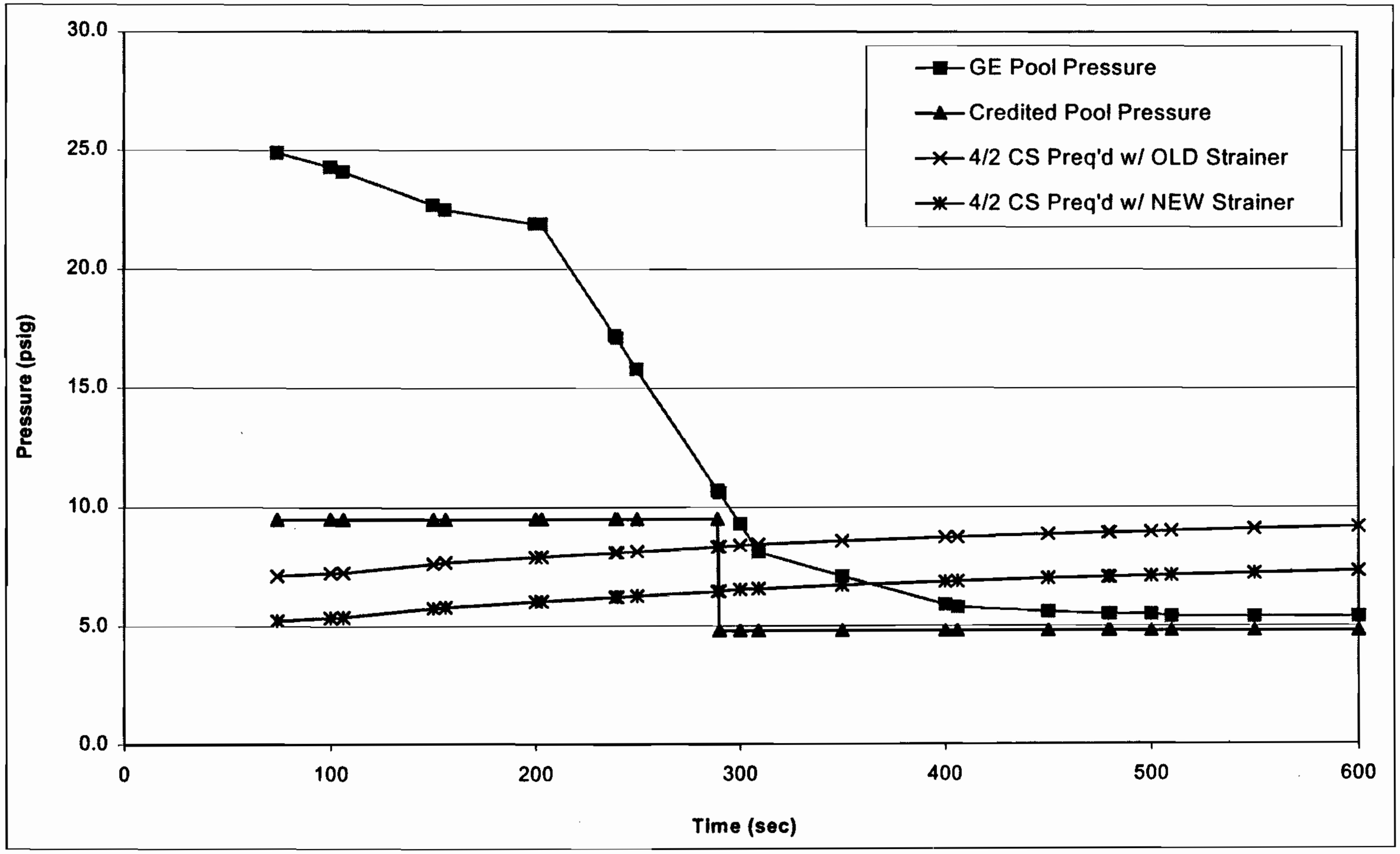

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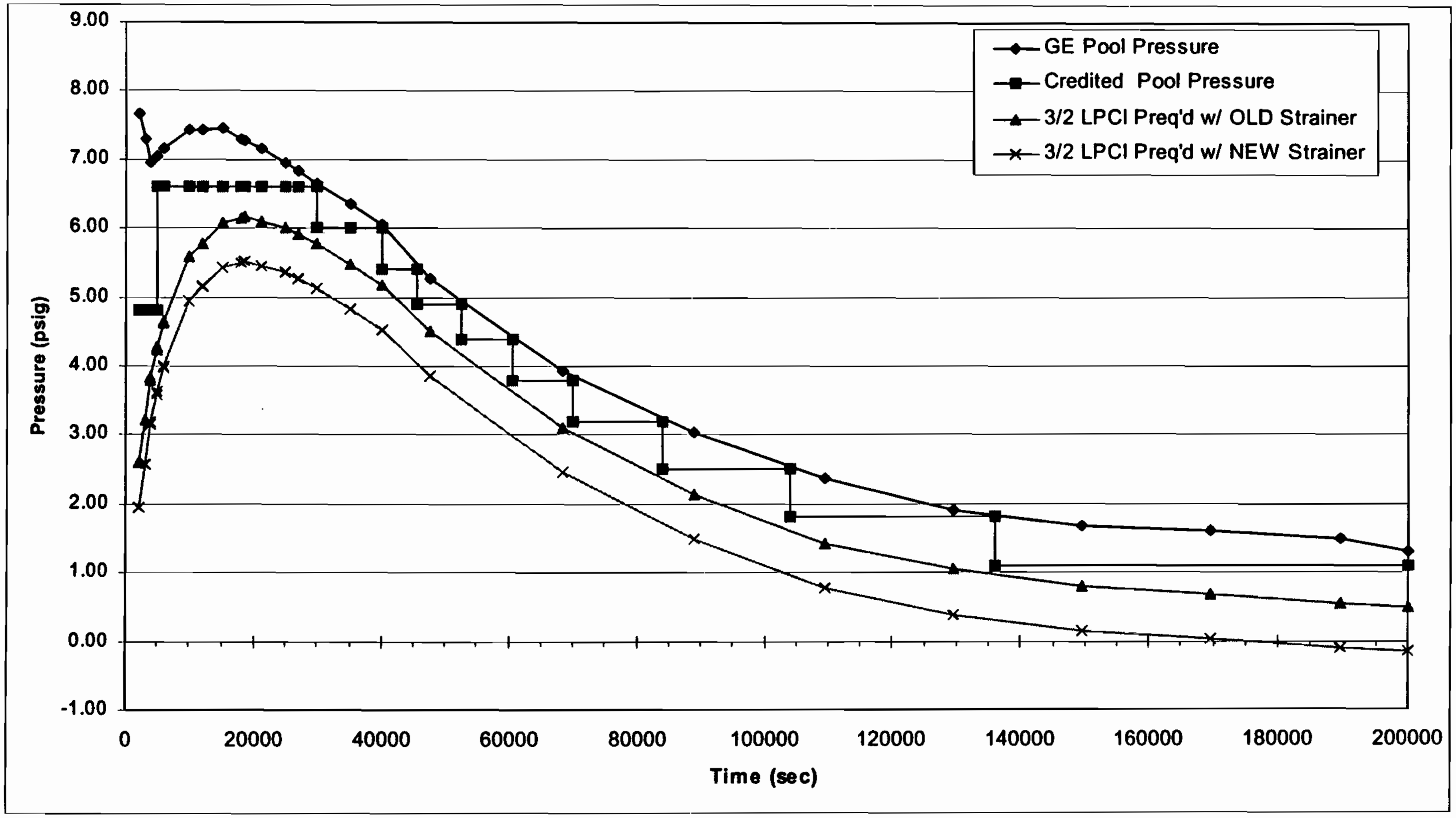
Figure 9-2
DNPS Long Term LPCI NPSH



Question

10. ELTR2 section 4.1.8.5 notes that the higher vapor pressure associated with increased suppression pool temperatures will reduce the NPSH available to the RHR and LPCS pumps and as a result the adequacy of the RHR and LPCS pumps will be evaluated at these increased temperature conditions. Were alternatives other than increased credit for overpressure considered, such as other means to enhance suction pressure, pump replacement or modification?

Response

The significant factors that determine the NPSHa for the ECCS pumps are as follows.

- The relative position and configuration of the associated piping and equipment, which controls suction elevation head and pressure flow losses
- Torus water temperature, which controls vapor pressure
- Torus overpressure, which contributes to suction pressure
- Pump flow rate, which relates to suction pressure losses
- Pump replacement

As discussed in Question 9, minimum pump flow, maximum water temperature and minimum overpressure were used in the NPSHr evaluation.

Changes to piping and equipment configuration and type were not considered as viable alternatives. To improve NPSHa, changes such as suction piping replacement or lowering of the pumps relative to the suppression pool would be required. Such changes are very difficult, require lengthy outages, and are very expensive, and are, therefore, considered impractical.

Question

11. The application is unclear or inconsistent regarding some of the requested changes for the license condition on containment overpressure. Clarify your request for these changes as noted in comment column of the following tables for Dresden and Quad Cities;

Dresden Containment Overpressure Credit (psi)

Time (seconds)	*Current license condition*	*Requested condition*	*NEDC-32962P Safety Analyses Report*	*Comment*
0-240	*9.5*			
0-290		*9.5*	*9.5*	
240-480	*2.9*			
290-5000		*4.8*	*4.8*	

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Dresden Containment Overpressure Credit (psi)

480-6000	*1.9*			
5000-30000		*~~4.25~~ 5.2*	*~~5.3~~ 5.2*	*Clarify - April 13, 2001 submittal supplement revised to 5.2 psi - however difference column remains 0.8 psi*
6000-end	*2.5*			
30000-end		*NA*	*From 30000 seconds to the end of the accident, the available pressure and require pressure decrease in parallel fashion. Minimum margin between available pressure and required pressure during this period is 2.4 psi.*	*Was this an omission or is no credit being requested? If no credit explain how long term NPSH availability has been achieved; considering the previous need of 2.5 psi and proposed need for 5.2 psi at 5000-30000 seconds.*

Quad Cities Containment Overpressure Credit (psi)

Time (seconds)	*Current amendment request*	*EPU Requested condition*	*NEDC-32961P Safety Analyses Report*	*Comment*
0-210	*8.0*			
0-290		*9.5*	*8*	*clarify/correct*
210-600	*2.5*			
290-5000		*4.8*	*4.8*	
600-10000	*3.0*			

Quad Cities Containment Overpressure Credit (psi)				
5000-30000		*4.25*	*6.75*	*Clarify/correct*
10000-end	*3.5*			
30000-end		*NA*	*From 30000 seconds to the end of the accident, the available pressure and require pressure decrease in parallel fashion. Minimum margin between available pressure and required pressure during this period is 1.6 psi.*	*Was this an omission or is no credit being requested? If no credit, explain how long term NPSH availability has been achieved; considering the previous need of 3.5 psi and proposed need for 4.25 (6.75) psi at 5000-30000 seconds.*

Response
The inconsistencies between the Reference 3 Power Uprate Safety Analysis Report (PUSAR) Table 4-2 and the license amendment request will be resolved in a revised PUSAR that will be submitted separately.

Question
13. *In many places, the bases for changing a Technical Specification relating to the extended power uprate increased power level is not provided. Selected parameters, such as the revised power level for applicability of the turbine stop valve and turbine control valve fast closure reactor trips (38.5% versus 45% currently) have stayed the same, as measured by thermal power, to maintain the same analyses power level. Selected other changes have been addressed as acceptable at the increased thermal power associated with the existing stated percentage of reactor thermal power (RTP). For example in several places the safety analyses report NEDC-32926P notes that the technical specification surveillance applicability threshold for the rod block monitor remains with a value of 30% RTP. In other places no basis is provided for the 17% increase in requirement resulting from the EPU. For example, TS SR 3.3.1.1.2 to Channel check APRMs above 25 (21.4)% RTP to verify the absolute difference is less than 2 (1.7)% RTP; the feedwater system and main turbine high water level trips required to be operable above 25 (21.4)% RTP; among others. If these changes have been addressed, provide a comprehensive cross reference to the basis for all Technical Specifications which reference RTP. If not, either provide the basis for these changes or propose changes which maintain the existing thermal power for the associated Technical Specification.*

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Quad Cities Nuclear Power Station, Units 1 and 2

Response

The following table provides a listing of all the DNPS and QCNPS TS references to % rated thermal power (RTP) that are not being proposed for change in Reference 3. The table provides either a basis for the TS value following EPU, or a reference to the PUSAR section that discusses the basis.

TS Reference	Page	RTP	Basis
Safety Limit 2.1.1 (Reactor Core SLs)	2.0-1	≤ 25%	PUSAR Section 9.1 paragraph 8
3.1.3 Condition D (Control Rod Operability)	3.1.3-3	> 10%	PUSAR Section 5.3.12
Surveillance Requirement (SR) 3.1.4.1 (Control Rod Scram Time)	3.1.4-1	40%	See Note 4
SR 3.1.4.4 (Control Rod Scram Time)	3.1.4- 2	40%	See Note 4
LCO 3.1.6 (Rod Pattern Control)	3.1.6-1	≤ 10%	PUSAR Section 5.3.12
Section 3.2 (Power Distribution Limits)	3.2.1-1 thru 3.2.4-1	≥ 25%	PUSAR Section 9.1 paragraph 8
SR 3.3.1.1.2 (APRM Gain)	3.3.1.1-4	≥ 25%	PUSAR Section 9.1 paragraph 8
SR 3.3.2.1.2 (Control Rod Block)	3.3.2.1-4	≤ 10%	PUSAR Section 5.3.12
SR 3.3.2.1.3 (Control Rod Block)	3.3.2.1-4	≤ 10%	PUSAR Section 5.3.12
SR 3.3.2.1.5 (RBM not bypassed)	3.3.2.1-5	≥ 30%	PUSAR Section 9.2.1.2, paragraph 4
SR 3.3.2.1.6 (RWM not bypassed)	3.3.2.1-5	≤ 10%	PUSAR Section 5.3.12
Table 3.3.2.1-1 Note a (RBM)	3.3.2.1-6	≥ 30%	PUSAR Section 9.2.1.2, paragraph 4
Table 3.3.2.1-1 Note b (RWM)	3.3.2.1-6	≤ 10%	PUSAR Section 5.3.12
LCO 3.3.2.2 Applicability and Action C.2 (Feedwater / Main Turbine High Level Trip)	3.3.2.2-1 3.3.2.2-2	25%	PUSAR Section 9.1 paragraph 8
SR 3.4.2.1 (Jet Pumps)	3.4.2-1	> 25%	PUSAR Section 9.1 paragraph 8
Section 3.6.2.1 (Suppression Pool Temp)	3.6.2.1-1 3.6.2.1-2	≤ 1%	See Note 1
Section 3.6.2.5.(Drywell–Suppression DP)	3.6.2.5-1	15%	See Note 2
LCO 3.6.3.1 and Action B.1 (Primary Containment O_2)	3.6.3.1-1	15%	See Note 3
LCO 3.7.7 Applicability and Condition B (Main Turbine Bypass System)	3.7.7-1	≥ 25%	PUSAR Section 9.1 paragraph 8

Notes:

1. According to the bases for Technical Specification (TS) 3.6.2.1, the 1% RTP value is approximately equal to normal system heat losses, such that the reactor is effectively shutdown. This number was based on engineering judgment and would still apply to EPU. It should be noted that the containment analyses which are used to confirm that containment pressure and temperature limits are not exceeded consider reactor thermal powers up to 102% RTP. It is therefore expected that the increase in the RTP with EPU would not result in exceeding the design basis maximum allowable values for primary containment pressure or temperature if an accident or transient event with pool heatup were to occur at 1% RTP. Therefore, the reference to a 1% RTP is retained for TS 3.6.2.1.

2. According to the bases for TS 3.6.2.5, the drywell-to-wetwell pressure difference must be controlled when the primary containment is inert. The 15% RTP value is related to the TS requirements to inert the containment within 24 hours after the reactor is greater than 15% RTP during startup and to de-inert the containment within the last 24 hours prior to reaching 15% RTP during a plant shutdown (see TS 3.6.3.1-1, "Primary Containment O_2"). As stated in the response for TS 3.6.3.1-1 in note 3 below, the current basis and applicability of the <15% RTP is valid for EPU with respect to containment inerting requirements.

3. The current basis and applicability of the <15% RTP window for relaxation of the inerting requirement during startup and shutdown is valid for EPU. As described in bases for TS 3.6.3.1, the probability of an event that generates hydrogen during these windows is low.

4. For EPU, the requirement remains unchanged at 40% RTP. This power level is not a critical value and is chosen for convenience. The 40% RTP maximum is above the low power setpoint that allows control rod drives to be withdrawn for scram testing. It also allows scram testing to be performed sufficiently early in the startup mode when the power level is low.

Question

14. Section 6.4.1.1 Safety-related loads for service water system notes that increased heat load imposed on the containment cooling water system is within the existing system capacity following the most demanding design basis event. What is the increase in the heat load for the CCSW system and what is the system capacity?

Response

The containment cooling service water (CCSW) system is used at the DNPS Units 2 and 3 to remove heat from the suppression pool. QCNPS Units 1 and 2 use the residual heat removal service water (RHRSW) system, which serves the same function as the CCSW system at DNPS.

The heat removal rate at design conditions for the DNPS Units 2 and 3 CCSW Systems is 71 MBTU/hr with 165°F suppression pool temperature and 95°F service water temperature. As the suppression pool temperature increases, the heat load (i.e., heat removal rate) will also increase and the heat load will be the maximum at the peak suppression pool temperature. For the pre-EPU power level, an analysis was performed using the same methodology as for the EPU power level. This analysis determined that, for the pre-EPU power level, the peak suppression pool temperature is determined to be 188°F for the limiting design basis event, and the heat load at this suppression pool temperature based on the design system capability is 94 MBTU/hr. At EPU conditions, using the same methodology, the peak suppression pool temperature with the same design system capability increases to 196°F for the same limiting design basis event. The maximum heat load at this peak temperature is 102 MBTU/hr. This means that the EPU results in an increase of 8 MBTU/hr in the maximum heat load for the DNPS Units 2 and 3 CCSW Systems.

The heat removal rate at design conditions for the QCNPS Units 1 and 2 RHR Systems is 66 MBTU/hr with 165°F suppression pool temperature and 95°F service water temperature. For the pre-EPU power level, an analysis was performed using the same methodology as for the EPU power level. This analysis determined that the peak suppression pool temperature is 190°F for the limiting design basis event, and that the heat load at this suppression pool temperature based on the design system capability is 90 MBTU/hr. At EPU conditions, using this same methodology, the peak suppression pool temperature with the same design system capability increases to 199°F, and the heat load at this peak temperature is 98 MBTU/hr. Thus, an increase of 8 MBTU/hr in the maximum heat load occurs for the QCNPS Units 1 and 2 RHR Systems due to EPU.

Since the CCSW and RHRSW systems maintain the suppression pool temperatures at acceptable levels, the increased heat load on these systems is acceptable.

Question

16. Section 6.4.3. The safety analyses report states that reactor building closed cooling water system heat loads do not increase significantly following EPU. Provide the pre- and post- peak EPU heat loads for the shutdown cooling heat exchanger; spent fuel pool heat exchangers; reactor recirculation pumps; the design RBBCW heat removal capability and total peak heat load post-EPU. Include consideration of the limiting single failure or no failure if this is a more limiting case. Also include an evaluation of the maximum heat removal capability of the system.

Response

The pre- and post-EPU heat loads are provided in Tables 16-1 through 16-4. Although several individual heat loads have increased as a result of EPU, the total system heat load has not increased significantly.

Single failure of a component in the RBCCW system is accommodated by a swing heat exchanger and pump shared between the two units at each site.

To maximize the heat load delivered to the RBCCW system, the system was evaluated assuming three RBCCW heat exchangers on-line with three RBCCW pumps, three shutdown cooling heat exchangers on-line for DNPS Units 2 and 3, and two fuel pool heat exchangers on-line for DNPS Units 2 and 3 and QCNPS Units 1 and 2. This is not a normal operating configuration since a full core offload is assumed with an initial reactor coolant temperature of 339°F. The following results were obtained.

DNPS Unit 2

Heat Removed by RBCCW System: 281.2 MBTU/hr
RBCCW Heat Exchanger Cold Temperature: 107.6°F
RBCCW Heat Exchanger Hot Temperature: 133.7°F

DNPS Unit 3	
Heat Removed by RBCCW System:	269.6 MBTU/hr
RBCCW Heat Exchanger Cold Temperature:	107.0°F
RBCCW Heat Exchanger Hot Temperature:	132.1°F

QCNPS Units 1 & 2	
Heat Removed by RBCCW System:	38.4 MBTU/hr
RBCCW Heat Exchanger Cold Temperature:	104.1°F
RBCCW Heat Exchanger Hot Temperature:	114.0°F

Since the resulting heat exchanger hot temperatures remain acceptable, the evaluation results shown above demonstrate that the RBCCW System is capable of removing the maximum EPU calculated heat loads for each of the modes of operation.

Question

17. Section 6.4.5 addresses the adequacy of the ultimate heat sink (UHS). In the event of downstream dam losses, the water trapped in the intake and discharge bay becomes the UHS for Quad Cities 1&2 and the water trapped in the intake canal becomes the UHS for Dresden 2&3. Considering the increased decay heat associated with the EPU, provide details of the analyses of the available water supply trapped in these UHSs for safe shutdown for all units; addressing conformance with Regulatory Guide 1.27. Include any revised timing of required operator actions to maintain the UHS; if any.

Response

The design basis for the DNPS and QCNPS Cities UHS was established prior to the issuance of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants." The design bases for the DNPS and QCNPS UHS are provided in UFSAR Section 9.2.5, "Ultimate Heat Sink," for each plant.

The capability of the UHS for operation at EPU conditions was evaluated within the context of the UHS design bases as stated above. The results are provided as follows.

Dresden UHS Evaluation:

Dresden takes credit for the isolation condenser to bring the reactor temperature to 212°F. For pre-EPU design basis conditions, the amount of water required by each unit to remove decay through the isolation condenser is 2.5 million gallons over a 30 day period. For operation at EPU, 30 days requirements were calculated to be 2.9 million gallons of water per unit, which is below the 6 million gallons of water available.

As a result of the slight increase in the usage of water at EPU conditions, manual actions to place portable pumps to provide make-up water from the river to the UHS would have to be performed sooner, but this is a negligible impact, given the small increase in volume required.

Question
31. The impact of the increased heat load on the spent fuel pool (SFP) cooling is information we need to be able to fully evaluate your request for an extended power uprate for DNPS Units 2 and 3 and Quad Cities Units 1 and 2. The use of the terminology "planned" and "unplanned" has been used by the staff for the review of SFP heat load changes since questions arose in the mid-1990's regarding refueling practices at Millstone Unit 1. A planned offload is the offload of fuel assemblies to the SFP for any expected (or planned) reason. An unplanned offload is the offload of fuel assemblies to the SFP due to an unforeseen condition (e.g., unexpected shutdown that includes an offload). This difference in terminology was made to ensure SFP temperature evaluations accurately reflected actual licensee practices.

Section 6.3.1 of the safety analyses report notes that the EPU increases heat load on the spent fuel pool cooling system; and discusses analysis confirming the capability of the system to maintain adequate fuel pool cooling. Table 6-2 contains design conditions which are unchanged between pre- and post-uprate except using a 24 month fuel cycle for Quad Cities Units 1 and 2. The table additionally notes that the bulk pool temperature is less than 150°F for a full core off-load, with fuel pool with maximum capacity and with shutdown cooling in fuel pool assist mode. Additional staff review of the UFSAR indicates that both DNPS and Quad Cities were using different guidelines for evaluation of SFP cooling than the current staff practice noted above. These methods include evaluations of partial core offloads (normal) and full core offloads (abnormal); and additionally allow cycle-specific analyses of offloads in lieu of the bounding analyses described in the UFSAR. It is not clear to the staff what assumptions were used to support the EPU safety analyses report.

Please submit the results of additional evaluations on the impact of the increased EPU heat load on the SFP and supporting systems. Your evaluation of the spent fuel cooling system should address both the planned and unplanned offload conditions. The staff will accept either (1) bounding or (2) cycle-specific analyses, or both can be used.

Response
The QCNPS and DNPS fuel pool cooling and cleanup system (FPCCS) evaluation includes an assessment of the impact of uprated conditions on system operation, using partial core offloads (i.e., up to approximately 42% of a full core), which are the normal condition and full core offloads, which are the abnormal condition.

The current licensing basis for these plants is described in Updated Final Safety Analysis Report (UFSAR) Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System," which states that the SFP analyses are performed with the following conditions.

- Partial core offload requires that the fuel pool temperature must remain less than 141°F at DNPS and 140°F at QCNPS, with the single failure of a cooling train.
- Full core offload requires that temperatures remain below 145°F at DNPS and 150°F at QCNPS without assuming a single failure.

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Future refueling outages at DNPS and QCNPS are planned for partial core offloads. However, in a discussion between representatives of EGC and members of the NRC regarding this topic on August 2, 2001, the NRC stated that NRC policy for power uprates was to require that licensees demonstrate the capability to accommodate a planned full-core offload with a single failure of a cooling train. Accordingly, if DNPS and QCNPS should plan for a full core offload during future refueling outages, EGC will perform an analysis of the capability of the spent fuel pool cooling system and the spent fuel pool to perform their function assuming a single failure of a cooling train.

The EPU analysis for both QCNPS and DNPS, as discussed below, was performed to bound the various cases analyzed previously in the respective UFSARs. The EPU analysis for both the normal and abnormal conditions considers that the SFP is already filled with fuel assemblies discharged from previous refueling outages (i.e., 2867 bundles) with the exception of one batch offload to be analyzed for the current cycle (i.e. 306 bundles), with room for a full core offload (i.e., 724 bundles). Also, it is assumed that all previous batches of fuel assemblies have been exposed to a 24 month fuel cycle at the power uprated condition. Additional guidelines used for evaluation of SFP cooling are discussed below.

Each of the FPCCS primary system components was evaluated. These are defined as those flow-affected components that affect system operation due to power uprate, such as heat exchangers, pumps, and filter/demineralizers.

The following methodology and acceptance criteria for the SFP temperature have been used for the power uprate evaluation.

Methodology
The decay heat load is calculated for the two bounding scenarios, "normal" condition, and "abnormal" condition, as a function of time. The SFP temperature is calculated as a function of time, considering the following major elements of heat sources and heat sinks.

- Heat load from the fuel bundles discharged from previous refueling outages
- Heat load from the fuel bundles discharged during the current refueling outage
- Cooling by the FPCCS for QCNPS; FPCCS and shutdown cooling (SDC) for DNPS
- Cooling by evaporation from the pool surface

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DNPS Assumptions and Acceptance Criteria

Single failure need not be assumed for this case, so this is accomplished with both trains of FPCCS (two pumps, two heat exchangers) and one SDC system loop in fuel pool cooling assist mode.

The required makeup flow of about 30 gpm for the partial core offload case is below the existing system capability of 54 gpm. For the full core offload case the makeup requirement is 70 gpm. There are several fire hoses that are also available to provide makeup water for the full core offload case or for the pool in the event of loss of fuel pool cooling. There are three sources for water: contaminated demineralization system, clean demineralization system and the fire protection system. Each fire hose is capable of delivering over 90 gpm. Therefore the makeup flow is much greater than the 70 gpm water loss calculated due to EPU.

Normal Condition - Batch Offload
A heat sink temperature of 95°F is assumed to be available for cooling the FPCCS heat exchangers (including SDC heat exchanger for DNPS) and the SFP is assumed to be initially at 110°F for these conditions.

The fuel transfer from the RPV to the SFP is initiated at 100 hours after reactor shutdown and with fuel transfer rate of ten fuel bundles per hour. When the fuel transfer is initiated, the fuel pool gate is assumed to open, and stay open until the end of the fuel transfer. At the end of fuel transfer, the fuel pool gate is assumed to be closed, and the heat load in the RPV is assumed to be cooled by the RHR system (QCNPS) or the SDC system (DNPS). While the fuel pool gate is open, the surface area of the reactor cavity is added for additional evaporation and the water mass in the reactor cavity is also used for additional heat absorption.

With these assumptions, the SFP temperature versus time is calculated, as is the evaporative loss from the pool surface. Assuming all fuel pool cooling is lost for the above batch offload scenario, at the time of peak SFP temperature, the time to reach the boiling point and the boiloff rate is calculated. The acceptance criterion for the SFP temperature is to be at or below 140°F for QCNPS and 141°F for DNPS.

Abnormal Condition - Full Core Offload

A heat sink temperature of 95°F is assumed for cooling the heat exchangers for FPCCS (and SDC heat exchanger for DNPS).

The fuel transfer from the RPV to the SFP is initiated at 100 hours after reactor shutdown and with fuel transfer rate of ten fuel bundles an hour.

The SFP temperature and the evaporative loss are calculated for this case. Then, assuming all fuel pool cooling is lost for the above core offload scenario at the time of peak SFP temperature, the time before the pool reaches the boiling point is calculated, and the boiloff rate is calculated.

The abnormal condition acceptance criterion for the SFP temperature is to be at or below 150°F.

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Results
The results of evaluations on the impact of the increased EPU heat load on the SFP and supporting systems are included in Tables 33-1 and 33-2. These evaluations indicate that the current requirements for SFP temperature can be maintained under EPU conditions.

Question
31.1 Bounding Analysis - Your response for a bounding analysis should include two scenarios planned and unplanned offloads.

A)Planned Offload Calculation - Planned offload is the offload of fuel assemblies to the SFP for any expected (or planned) reason.
Analysis conditions:
1) decay heat load is from spent fuel that is "planned" to be offloaded, either full or partial core plus heat load from an SFP with all other storage locations filled
2) bulk SFP temperature must remain below 150°F
3) worst single active failure, including common cause failures (not just one train)
4) initial conditions highest ultimate heat sink temperature; fouled heat exchangers.
If the resultant temperature is above 150°F, you should perform and submit an analysis to demonstrate that the SFP structure can withstand the new high temperature for long periods of time.

B) Unplanned Offload Calculation - An unplanned offload is the offload of fuel assemblies to the SFP due to an unforeseen condition (e.g., unexpected shutdown that includes an offload).
Analysis conditions:
1) decay heat load is based on a full core offload plus refueling load that has decayed for 36 days plus heat load from an SFP with all other storage locations filled
2) bulk SFP temperature must remain below boiling
3) no single failure needs to be considered

Response
For a discussion of planned and unplanned offloads, see the response to Question 31 above.

Question
31.2 Cycle-specific Analysis - You can alternately opt to perform a calculation prior to every planned offload using the actual conditions at the time of the offload. The wait time for offload can be adjusted, as long as the time is not shorter than what is assumed for the fuel handling accident. For unplanned offload, you can either commit to performing the same calculation prior

to offload or have a bounding calculation for unplanned offloads only, using the same guidelines as in Section 31.1 B) above.
Cycle-specific analysis conditions
1) decay heat load based on actual number of fuel assemblies planned to be offloaded plus heat load from actual assemblies in the previously loaded into pool
2) use actual system conditions ultimate heat sink temperature; heat exchanger fouling
3) worse active single failure, including common cause failures (not just one train)
4) bulk SFP temperature must remain below 150°F
5) include temporary modifications, if any

Response
The calculations performed for EPU are expected to be bounding for partial core offloads. As discussed in the response to Question 31 above, if DNPS and QCNPS should plan for a full core offload during future refueling outages, EGC will perform an analysis of the capability of the spent fuel pool cooling system and the spent fuel pool to perform their function assuming a single failure of a cooling train.

The calculations performed for EPU are expected to be bounding for unplanned offloads.

Question
32. Ability to supply adequate make-up source in event of loss of SFP cooling
Considering any analyses changes, re-confirm time to boil-off is sufficient to allow mitigative actions and the make up water required is within the system capacity in case of a complete loss of cooling to the SFP. Provide time to boil-off and boil-off rate.

Response
Time to boil and boil-off rates are given in the attached Tables 31-1 and 31-2. The makeup water capability is discussed in the response to Question 31.

Question
33. Section 4.7 on post-LOCA combustible gas control notes margin changes in various parameters associated with the EPU and additional impact of GE14 fuel introduction on metal-water hydrogen production. The 5% oxygen limit is reached in 19 hours, versus 25 hours pre-EPU. The minimum stored volume of nitrogen to maintain containment atmosphere below the 5% flammability limit for seven days will be 141,000 scf following EPU. Considering the increased nitrogen storage requirement and the reduced time to reach oxygen flammability concentrations following a design basis accident, address why technical specifications should not be added for the operability and surveillance of the containment atmosphere dilution system, including nitrogen storage (Reference BWR/4 STS 3.6.3.4, in accordance with 10 CFR 50.36(c)(2)(ii) criterion 3 - A system that is part of the primary success path and which functions to mitigate a design basis accident that presents a challenge to the integrity of a fission product barrier).

Response

The DNPS and QCNPS TS were recently revised to reflect the BWR Improved Standard Technical Specifications as noted in Reference 6. NUREG-1433, Specification 3.6.3.4, "Containment Atmosphere Dilution (CAD) System," was not included in the DNPS and QCNPS Improved Technical Specifications since the current licensing basis did not include requirements for a CAD system. In Reference 7, the NRC approved the deletion of the technical specification (TS) requirement for the primary containment nitrogen system based upon relocating these requirements to the UFSAR. The nitrogen system supports the requirements for primary containment oxygen concentration specified in TS 3.6.3.1. The nitrogen system also performs the CAD system function to maintain post-accident combustible gas concentrations within the primary containment at or below the flammability limits by purging the containment atmosphere with nitrogen. Since the NRC had previously determined that licensee controlled procedures and administrative controls were adequate to ensure nitrogen system operability, no new TS requirements associated with the EPU were deemed to be necessary. The nitrogen system continues to maintain the containment in an inerted condition as required by TS 3.6.3.1 and remain capable of purging the containment with nitrogen as necessary under accident conditions. Therefore, consistent with the current licensing basis, CAD requirements are not included in the TS for EPU.

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 16-1

Pre-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – DNPS Unit 2 or 3

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Reactor Recirculation Pump and Motors	0.9	0.9	0.5	0.9	0.9
Fuel Pool Coolers	7.3	7.3	7.3	7.3	-
Shutdown Heat Exchanger	-	90	48.5	-	-

Post-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – DNPS Unit 2 or 3

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Reactor Recirculation Pump and Motors	1.01	1.01	0.56	1.01	1.01
Fuel Pool Coolers	13(1)	13(1)	17(2)	13(1)	-
Shutdown Heat Exchanger	-	374.1(3)	48.5	-	-

Footnotes:

(1) At 17 days, heat load is 13 x 10^6 BTU/hr

(2) For emergency, full core offload, heat load will be 39.0 x 10^6 BTU/hr. However, the shutdown heat exchanger heat load will be 0 BTU/hr. (At 6 days, heat load is 17 x 10^6 BTU/hr)

(3) For commercial reasons, it is desirable to cool down the reactor within 24 hours for a refueling outage. The ability of the RBCCW system to achieve refueling temperature (140°F) within 24 hours was evaluated as part of the EPU evaluation. For this operating mode, an initial heat transfer from the shutdown heat exchangers of 374.1 x 10^6 BTU/hr and a total system heat transfer rate of 435.78 x 10^6 BTU/hr will be required. Although the design heat transfer rate with two RBCCW heat exchangers is 156 x 10^6 BTU/hr, and the design heat transfer rate with three RBCCW heat exchangers is 234 x 10^6 BTU/hr, the required heat transfer rate of 435.78 x 10^6 BTU/hr can be achieved at service water temperatures below the design value of 95°F. There are no safety concerns associated with achieving shutdown within 24 hours, so if the service water temperature is too high or if only two RBCCW heat exchangers are used, it will simply take longer to achieve cold shutdown.

Table 16-2

Pre-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – QCNPS Unit 1 or 2

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Fuel Pool Coolers	8.8	8.8	8.8	8.8	-
Reactor Recirculation Pump and Motors	0.9	0.5	-	0.5	0.5

Post-EPU RBCCW System Heat Loads (x 10^6 BTU/HR) – QCNPS Unit 1 or 2

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Fuel Pool Coolers	18(1)	18(1)	45(2)	18(1)	-
Reactor Recirculation Pump and Motors	1.01	1.01	-	1.01	1.01

Footnotes:

(1) For normal refueling, at 17 days heat load is 18 x 10^6 BTU/hr.
(2) For emergency, full core offload, heat load will be 45.0 x 10^6 BTU/hr. at 7.1 days after shutdown. (At 17 days, heat load is 35 x 10^6 BTU/hr.)

Table 16-3
Total System Heat Loads Cooled By RBCCW
DNPS Total RBCCW System Heat Loads (x 10^6 BTU/HR)

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Heat removal rate at original design conditions	156	234(3)	156	156	78
Pre-EPU heat removal rate (DNPS Unit 2)	61.04	145.87	69.65	54.87	5.4
Post-EPU heat removal rate (DNPS Unit 2(1))	66.85	435.78(2)	79.41	60.68	5.51

Footnotes:

(1) Heat loads at DNPS Unit 2 are most conservative
(2) For commercial reasons, it is desirable to cool down the reactor within 24 hours for a refueling outage. The ability of the RBCCW system to achieve refueling temperature (140°F) within 24 hours was evaluated as part of the EPU evaluation. For this operating mode, an initial heat transfer from the shutdown heat exchangers of 374.1 x 10^6 BTU/hr and a total system heat transfer rate of 435.78 x 10^6 BTU/hr will be required. Although the design heat transfer rate with two RBCCW heat exchangers is 156 x 10^6 BTU/hr, and the design heat transfer rate with three RBCCW heat exchangers is 234 x 10^6 BTU/hr, the required heat transfer rate of 435.78 x 10^6 BTU/hr can be achieved at service water temperatures below the design value of 95°F. There are no safety concerns associated with achieving shutdown within 24 hours, so if the service water temperature is too high or if only two RBCCW heat exchangers are used, it will simply take longer to achieve cold shutdown. The heat removal rate required to reach the TS cold shutdown temperature of 212°F is within the capability of the system.
(3) The third RBCCW heat exchanger is used during cooldown, to minimize outage time for refueling.

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Table 16-4
QCNPS Total RBCCW System Heat Loads (x 10^6 BTU/HR)

SERVICE	Mode of Service				
	Normal Operation	Cooldown	Shutdown (> 48 hrs)	Startup	A.C Power Failure
Heat removal rate at original design conditions	27.64(3)	27.64(3)	41.46(1) (3)	27.64(3)	13.82(3)
Pre-EPU heat removal rate	29.64	29.24	13.89	29.24	5.30
Post-EPU heat removal rate	38.95(2)	38.95(2)	50.09(2)	38.95(2)	5.81

Footnotes:

(1) The third RBCCW heat exchanger is used during emergency full core off-load.
(2) The heat exchangers are able to dissipate the higher heat loads without exceeding the current design basis cold RBCCW temperature of 105°F, based on a new maximum service water temperature of 90°F. The original design service water temperature from manufacturer data sheets was 95°F, but operating experience has shown that service water temperatures have never exceeded 90°F in the history of operation of QCNPS. It is concluded that with two RBCCW heat exchangers aligned to each QCNPS Unit and a maximum service water temperature of 90°F, the cold RBCCW temperature will not exceed 104°F for all operating modes except the emergency full core offload event. For the emergency full core offload event, the swing heat exchanger will need to be aligned to the unit with the emergency full core offload. All other operating parameters of the RBCCW system (flows, pressures, temperatures) will remain the same as before EPU.
(3) RBCCW heat exchanger design heat transfer values are based on manufacturer data sheets using 95°F as the inlet service water temperature. The design basis maximum service water temperature has been changed to 90°F, which results in heat transfer capability exceeding required load for all operating modes.

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

TABLE 31-1
QCNPS SPENT FUEL POOL DECAY HEAT LOAD PARAMETERS

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TABLE 31-2

DNPS SPENT FUEL POOL DECAY HEAT LOAD PARAMETERS

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References

1. Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 7, 2001
2. Letter from U. S. NRC to I. Johnson (Commonwealth Edison Company), "Issuance of Amendments," dated April 30, 1997
3. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000
4. Letter from J. P. Dimmette, Jr. (Commonwealth Edison Company) to U.S. NRC, "Request for License Amendment Pursuant to 10 CFR 50.90 Credit for Overpressure," dated January 29, 1999
5. Letter from U. S. NRC to O. D. Kingsley (Commonwealth Edison Company), "Quad Cities – Contractor Review of Head Loss Calculations Associated with Request for License Amendment," dated September 8, 2000
6. Letter from U. S. NRC to O. D. Kingsley (Exelon Generation Company, LLC), "Issuance of Amendments", dated March 30, 2001
7. U. S. NRC, "Safety Evaluation By The Office Of Nuclear Reactor Regulation Related to Amendment No. 150 to Facility Operating License No. DPR-19, Amendment No. 145 to Facility Operating License No. DPR-25, Amendment No. 171 to Facility Operating License No. DPR-29, and Amendment No. 167 to Facility Operating License No. DPR-30, Commonwealth Edison Company and MidAmerican Energy Company," dated June 28, 1996

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RS-01-162

August 13, 2001

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

References (1) Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

(2) Letter from K. A. Ainger (Exelon Generation Company, LLC) to U. S. NRC, "Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 8, 2000

In Reference 1, Commonwealth Edison (ComEd) Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications (TS) for Dresden Nuclear Power Station (DNPS), Units 2 and 3, and Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2, to allow operation with an extended power uprate (EPU). In a July 23, 2001, teleconference between members of the NRC and representatives of EGC, the NRC requested additional information regarding these proposed changes. The first portion of this information was provided in Reference 2. Attachment A to this letter provides the remainder of the requested information.

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Some of the information in Attachment A is proprietary information to the General Electric Company, and EGC requests that it be withheld from public disclosure in accordance with 10 CFR 2.790(a)(4), "Public Inspections, Exemptions, Requests for Withholding." This information is indicated with sidebars. Attachment B provides the affidavit supporting the request for withholding the proprietary information in Attachment A from public disclosure, as required by 10 CFR 2.790(b)(1). Attachment C contains a non-proprietary version of Attachment A.

Should you have any questions related to this letter, please contact Mr. Allan R. Haeger at (630) 657-2807.

Respectfully,

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Attachments:

Affidavit
Attachment A: Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Proprietary version)
Attachment B: Affidavit for Withholding Portions of Attachment A from Public Disclosure
Attachment C: Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Non-proprietary version)

cc:
Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station
NRC Senior Resident Inspector – Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

bcc: Dresden Unit 2/3 Project Manager - NRR
Quad Cities Project Manager - NRR
Manager of Energy Practice - Winston & Strawn
Director – Licensing, Mid-West Regional Operating Group
Manager – Licensing, Dresden and Quad Cities Station
Site Vice President – Dresden Station
Site Vice President – Quad Cities Station
Regulatory Assurance Manager – Dresden Station
Regulatory Assurance Manager – Quad Cities Station
W. Leech – MidAmerican Energy Company
D. Tubbs – MidAmerican Energy Company
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Document Control Desk Licensing (Electronic Copy)

STATE OF ILLINOIS)
COUNTY OF DUPAGE)
IN THE MATTER OF)
EXELON GENERATION COMPANY, LLC) Docket Numbers
DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3) 50-237 AND 50-249
QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2) 50-254 AND 50-265

SUBJECT: Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

K. A. Ainger

K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Subscribed and sworn to before me, a Notary Public in and for the State above named, this 13th day of August, 2001.

V Lynn Bernhagen
Notary Public

"OFFICIAL SEAL"
V. LYNN BERNHAGEN
Notary Public, State of Illinois
My Commission Exp. 05/30/2004

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Attachment A
Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation (Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 1, 2, 3, 7, 10, 11D, and 12D. Responses to NRC Questions 4, 5, 6, 8, 9, 11, (Parts A, B, C, and E), 12 (Parts A, B, and C), 13, and 14 were provided in a previous transmittal (Reference 1).

Question
1. In reference to Section 3.3.4 for the reactor internal structural evaluation, you stated that the structural assessment used guidelines and procedures similar to those in the design basis analyses. All applicable service levels, namely normal, upset, emergency, and faulted are considered consistent with the current design basis analyses. The loads considered in the evaluation include the reactor internal pressure differences, seismic loads, flow induced and acoustic loads due to the postulated recirculation line break (RLB-LOCA), thermal load effects, dead weight, and flow loads.

1A. Confirm whether the loads considered for the evaluation of the reactor internal components include the fuel lift loads, the safety relief valve discharge loads, annulus asymmetric pressurization and jet reaction loads during a main steam or a feedwater line break.

1B. Discuss the effects of the proposed extended power uprate (EPU) on the RLB-LOCA load and other design basis loads mentioned above.

Response
1A. Annulus asymmetric pressurization load and safety relief valve discharge loads due to seismic and dynamic loads are not part of the Dresden Nuclear Power Station (DNPS) and Quad Cities Nuclear Power Station (QCNPS) licensing and design bases applicable to reactor vessel internals. Fuel lift loads based on differential pressures for GE14 fuel at EPU conditions were evaluated and it was concluded that positive margin exists for all service levels. Additional discussion for annulus asymmetric pressurization and jet reaction loads are provided in the response to Question 5 provided in Reference 1.

1B. The effects of EPU on the loads considered for the core support structure and non-core support structure components are discussed in detail for each component in Section 3.3.4 (a) through (o) of Reference 2, Attachment E, Power Uprate Safety Analysis Report (PUSAR). Governing loads and stresses of reactor internals components are provided in the response to Question 2B.

Question
2A. In Section 3.3.2, you indicated that the reduction in some fatigue usage factors (CUFs) in Table 3-3a is a result of reduction in the conservatism and/or number of thermal cycles from the original analysis. Describe how you arrived at an accurate representation of the fatigue cycles which resulted in a reduction of CUF from 0.94 to 0.862 for the shroud support as provided in Table 3-3a.

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Attachment A
Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation (Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

2B. In regard to Section 3.3.4, provide the maximum calculated stress and CUFs for the reactor internal components evaluated for both the current design condition and the uprate power condition, the allowable code limits, and the code and code edition used in the evaluation for the power uprate. If different from the code of record, provide your justification.

Response

2A. The EPU CUF of 0.862 for the support skirt was reduced by removing conservatism from a previous analysis (CUF = 0.945). The 1989 analysis used 278 startup/shutdown cycles and 361 scram cycles. The support skirt was re-analyzed in 2000 to account for the then-current thermal cycle information; using 250 startup/shutdown cycles and 232 scram cycles (CUF = 0.838). The power uprate calculation used this information to scale up the CUF to 0.862. Consequently, the power uprate fatigue usage was an increase in CUF from the 2000 CUF of 0.838 to 0.862.

Scaling Technique

General Electric has developed a technique to conservatively scale the original stress report stresses to account for changes in the original pressures, temperatures, and nozzle flows as a result of EPU.

Many pressure vessel calculations select the three stress directions of the orthogonal coordinate system such that the shear stress components are zero; the normal stress components are the principal stresses. With this orientation, the pressure stresses are directly proportional to the increase in coolant pressure, and the magnitude of the principal stress resulting from thermal cycling is proportional to the temperature change during a thermal transient. When there are no changes in mechanical loads as a result of the EPU, the new magnitude of the principal stress is:

$$\sigma_{new} = \sigma_p * (P_{new}/P_{old}) + \sigma_t * (\Delta t_{new}/\Delta t_{old}) + \sigma_m$$

where:

σ_p = Original pressure stress
σ_t = Original thermal stress
σ_m = Original mechanical stress
P_{new} = EPU pressure
P_{old} = Original pressure
Δt_{new} = EPU temperature range
Δt_{old} = Original temperature range

or:

$$\sigma_{new} = \sigma_p * SCF_p + \sigma_t * SCF_t + \sigma_m$$

where:

SCF_p = Pressure stress scaling factor
SCF_t = Thermal stress scaling factor

Components that experience a change in internal coolant flow during operation have a flow scaling factor, SCF_f. The magnitude of the internal flow changes the convective heat transfer coefficient. The Biot Modulus is used to determine the effect of increased nozzle flows on the nozzle thermal skin stresses. It can be shown that:

$B_i \;\; \alpha \;\; h \;\; \alpha \;\; V^{0.8}$

where:

B_i = Biot Modulus, hL/k
h = Film convection coefficient
V = Flow velocity through nozzle

This relationship allows the flow scaling factor to be determined by the following:

$$SCF_f = (V_{new}/V_{old})^{0.8}$$

When the flow scaling factor is applied, a new thermal SCF is calculated using both the SCF_t and the SCF_f. The new thermal scaling factor is calculated using the following formula:

$$SCF_T = SCF_t * SCF_f$$

Most stress reports do not separately report the pressure, thermal, and mechanical stresses; therefore, it is not practical to calculate the scaled pressure or scaled thermal stresses. A conservative scaling technique, using the larger of the pressure and temperature scaling factors, is used to scale the entire stress magnitude. If a calculated SCF is less than unity, a SCF = 1.0 is used instead. This method is a conservative alternative to scaling the individual stress components because:

- The largest scaling factor is used for both the pressure and temperature SCF.
- The mechanical stresses are increased by the SCF even though the design mechanical loads did not increase.
- Conditions which generate a stress reduction (a SCF less than 1.0) are ignored.

The stress scaling technique may be further simplified by applying the SCF to the stress intensity alone, rather than applying the SCF to the principal stress components. A stress intensity, or stress difference, used to compare with the American Society of Mechanical Engineers (ASME) Code allowable values is determined by selecting the absolute value of the maximum difference between any pair of principal stresses. Consider the following example:

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$$
\begin{aligned}
S_{12,new} &= \sigma_{1,new} - \sigma_{2,new} \\
&= \sigma_{1,old} * SCF - \sigma_{2,old} * SCF \\
&= (\sigma_{1,old} - \sigma_{2,old}) * SCF \\
&= S_{12,old} * SCF
\end{aligned}
$$

Scaling Factors for the Support Skirt

The support skirt is located in Region B of the reactor and only experienced a change in temperature due to EPU conditions. Based on the scale factor equations discussed above, the highest normal startup SCF is 1.002 and the highest SCRAM SCF is 1.083.

Scaling Factors for Region B

		Pre- Power Uprate Condtions		Power Uprate Conditions		Scaling Factor
Zones	Description	Initial Temperature, F	Final Temperature, F	Initial Temperature, F	Final Temperature, F	SCF_1
3 – 4	Normal Startup	100	546	100	547	1.002
4 – 5	Normal Startup	546	538	547	539	1.000
4 – 5	Normal Startup	538	520	539	530	0.500
10 – 11	Scram	400	520	400	530	1.083

Support Skirt

The support skirt was re-analyzed in 1989 and accounted for the latest thermal cycle information at that time. Since the QCNPS and DNPS RPVs have the same usage factors, the QCNPS results apply to DNPS. The limiting transients for the support skirt are heatup and cooldown. The maximum primary plus secondary stress range (P + Q) is 82.88 Ksi which exceeds the Code allowable limit of $3S_m$. The P + Q stress intensity with thermal bending removed is scaled up by using the appropriate SCF and compared to the Code allowable.

$P + Q = (P + Q - \text{Thermal Bending})_{old} * SCF$

54.41 Ksi = 53.31 Ksi * 1.002

$54.41 \text{ Ksi} < 3S_m = 69.9 \text{ Ksi}$

Since the calculated value of the maximum primary plus secondary stress is greater than the $3S_m$ limit, an elastic-plastic analysis, as described in the Code is performed.

$S_{alt,new} = S_{P+Q+F} / 2 = [(S_n * SCF*(K_t - 1) + S_{surf} * SCF)/2]*K_e *(E_c/E_a)$
$= [(82.88*1.002*(2.12-1)+117.77*1.002)/2]*1.15*(30/28)$
$= 130.0$ Ksi.

where: $K_e = 1.0$ for $S_n \leq 3S_m$
$= 1.0 + [(1/n - 1)/(m - 1)]*(S_n /3S_m - 1) = 1.15$
for $3S_m < S_n < 3mS_m$
$= 1/n$, for $S_n > 3mS_m$

where:

$n = 0.2$ for Low Alloy Steel
$m = 2.0$ for Low Alloy Steel
$3S_m = 80.1$ Ksi
$S_n = P + Q = 82.88$ Ksi
$S_{surf} = 117.77$ Ksi
$E_c = 30E6$ psi
$E_a = 28E6$ psi
$K_t = 2.12$
SCF = 1.002 (Region B, Startup)

A thermal stress ratcheting check was performed and shakedown will occur. Therefore, thermal stress ratcheting is not a concern. For an alternating stress of 130.0 Ksi, the allowable number of cycles is 304. For a total number of startup/shutdown cases of 250, the fatigue usage factor is 0.822. Similarly, for SCRAM, the alternating stress was calculated using the above method with a SCF of 1.083 and is 45.5 Ksi. This stress allows 5860 SCRAM cycles. There are 232 SCRAM cases predicted for a 40 year life which gives a fatigue usage factor of .040. The total combined fatigue usage factor is:

$U_{Total} = U_{SU/SD} + U_{SCRAM}$
$U = n_1/N_1 + n_2/N_2 = 250/304 + 232/5860 = .822 + .040 = .862 < 1.0$

Response 2B

DNPS and QCNPS each have a separate set of seismic, reactor internal pressure differences (RIPD), and flow loads. However, the bounding EPU values are used for all component evaluations using a bounding unit approach with the exceptions of the site unique repair modifications that may require site specific loads.

The DNPS and QCNPS reactor internal components are not ASME code components. However, ASME code requirements have been typically used as guidelines in their design basis documents. EPU assessment is performed consistent with the design basis. The code of construction for the reactor vessel for DNPS is based on ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, 1963 Edition, including Summer 1964. The code of construction for the reactor vessel for QCNPS is based on ASME Boiler and Pressure Vessel

Code, Section III, Nuclear Vessels, 1965 Edition with Addenda through Summer 1965. For the core shroud modification projects (i.e., DNPS shroud repair in 1995), work was done to ASME Boiler and Pressure Vessel Code, Section III, Division 1, Nuclear Power Plant Components, 1989 Edition.

Any changes in loads as a result of the EPU are reconciled with respect to the loads used in the design basis analyses. If the EPU-based loads are bounded by the loads used in the design basis analyses, no further evaluation is performed. If the EPU-based loads are larger than the design basis loads, a reconciliation of the load increase is performed. The methodology used for reconciliation is to scale the existing design basis stresses proportionate to the loads, where possible. In some cases, incremental stress due to the load increase is determined, and its effect on the stress margin assessed. The resulting stresses are reconciled against the applicable allowable values, consistent with the design basis.

The structural adequacy of the internal components is assessed for the load changes associated with EPU, using the original/existing analysis as the design basis. This section summarizes the evaluation performed.

Shroud with Repair

The shroud loads affected by the EPU are the RIPDs across the core plate and the shroud head, and the postulated recirculation line break (RLB) LOCA acoustic and flow induced loads in the annulus. All other loads remain unchanged. Both DNPS and QCNPS shroud repairs were based on the RIPD values specified in the repair design specifications which have increased due to EPU. Because of the unique plant designs and RIPD loadings, separate evaluations were performed for DNPS and QCNPS. The net change in the vertical load due to the RIPDs is determined. Also, the lateral load due to the RLB LOCA acoustic and flow induced loads were determined and evaluated. The following summarizes the results for each plant.

QCNPS

The increase in the loads due to EPU remain within the margin available in the design loads used for the original repair stress analysis. Therefore, the shroud repair components and shroud remain qualified for EPU conditions.

For Tie Rod Margins:

Load Case	EPU Incremental Increase – Kips	Existing Margin * - Kips
OBE+ normal RIPD	8.7	39
DBE+ normal RIPD	8.7	108
Acoustic+ normal RIPD+DBE	65.9	108

For Spring Rod Margins: (Faulted condition)

Component	Acoustic Load - Kips	Existing Margin * - Kips
Upper Spring	36.7	51.4
Middle Spring	25.2	33
Lower Spring	26.55	138

* The adequacy of the structural strength of different internals was established during the shroud repair at a first round of analysis. Then, in a second round evaluation, the conservatism of the seismic analysis was reduced leading to load reduction in most cases. In what follows, when appropriate, the difference between the EPU and pre-EPU values are tabulated and compared to the pre-EPU available margins. The margins are due to the reduction of conservatism of the seismic loads between the first and second round dynamic analyses.

DNPS

The increased loads due to EPU remain within the margin available in the design loads used for the original repair stress analysis, except as follows. The increased faulted condition loads (RLB acoustic load in combination with the design basis event (DBE) seismic load) in the middle lateral spring and the tie rod assembly exceeded the original shroud repair faulted condition design loads. However, the resulting increased stresses due to the increased load remain within allowable stresses in the faulted condition. The tie rod assembly item with the least margin was the lower support toggle bolt.

Component	Pre-EPU (Ksi)	EPU (Ksi)	Stress Allowable (Ksi)
Middle Spring (faulted)	74.93	77.18	142.54
Tie Rod (faulted-toggle bolt)	104.6	125.6	142.54

The maximum shroud reaction stress (at the middle support location which includes the tie rod load effect) is shown below. The shroud repair components and shroud remain qualified for EPU conditions.

Component	Pre-EPU (Ksi)	EPU (Ksi)	Stress Allowable (Ksi)
Shroud (Pm+Pb)	22.59	27.108	50.80

Shroud Support

The primary load input to the shroud support from the shroud repair is the increased tie rod load due to RIPD changes across the core plate and shroud head coupled with increased RIPD changes across the shroud support. Recirculation line break acoustic loads are also considered. By a conservative scaling of the stress results by the increased load factors, it was determined that all stresses remain within original allowable stress values. Thus, the shroud support remains qualified for EPU conditions.

QCNPS

Due to RIPD changes across the core plate and shroud head, the shroud repair tie rod loads increased, however, they were within the original design basis loads. The tie rod loads in conjunction with RIPD increases across the shroud support plate and the RLB acoustic load resulted in increased stresses. The upset condition stress increased from 22,400 to 28,224 psi which is within the allowable of 34,950 psi and the faulted condition stress increased from 37,480 to 55,100 psi which is within the faulted allowable of 69,900 psi.

DNPS

Due to RIPD changes across the core plate and shroud head, the shroud repair tie rod loads increased above the original design basis loads. The tie rod loads in conjunction with RIPD increases across the shroud support plate and the RLB acoustic load resulted in increased stresses. The upset condition stress increased from 24,300 to 30,618 psi which is within the allowable of 34,950 psi and the faulted condition stress increased from 47,400 to 61,620 psi which is within the allowable of 69,900 psi.

Core Plate

The only applicable load affected by EPU is the pressure drop across the core plate. However, the EPU-based pressure drops across the core plate are within the established allowable pressure drops for core plate integrity concerns. Therefore, the core plate assembly remains qualified for the EPU.

The following table summarizes comparison of EPU RIPDs with the allowable RIPDs for service conditions consistent with the design basis.

Service Conditions	Pre-EPU RIPD, psi	EPU RIPD, psi	Allowable RIPD, psi
Normal	21.09	22.37	23.02
Faulted	28.0	29.5	44.96

Top Guide

The only applicable load affected by the EPU is the pressure drop across the top guide. Consistent with the design basis, the uplift force due to the pressure drop was assessed in conjunction with seismic accident events. The EPU RIPD values are all within maximum allowable value of 2.55 psi for the plant seismic loading. The maximum RIPD value increased from 0.41 to 0.83 psi for EPU condition (faulted), which is less the allowable of 2.55 psi. Therefore, the top guide remains qualified for the EPU.

Control Rod Drive Housing

The control rod drive (CRD) housing internal to the vessel is subjected to the following primary loads: weight (guide tube + fuel), pressure, scram loads, seismic loads, and the flow loads in the lower plenum. As a result of EPU, there is no change in these load conditions. Also, the temperature change in the lower plenum is insignificant (on the order of 1.3°F) based on the results of the recirculation system analysis. Thus, the structural integrity of the CRD housing internal to the vessel is maintained in EPU condition.

Control Rod Guide Tube

The only applicable loading affected by the EPU is the pressure drop across the control rod guide tube, which is the same as the pressure drop across the core plate. The design basis loads (static pressure and seismic) for the standard component bound the EPU RIPD loads. Also, the changes in temperature and flow conditions in the lower plenum are insignificant based on the results of the recirculation system analysis. Therefore, the control rod guide tube remains qualified for the EPU.

Service Conditions	Pre-EPU RIPD, psi	EPU RIPD, psi	Design Basis RIPD, psi	Results/ Comments
Upset	23.49	24.77	26.0	Acceptable
Faulted	28.0	29.5	37.5	Acceptable

Orificed Fuel Support

The only applicable loading affected by the EPU is the pressure drop across the orificed fuel support (OFS). The OFS is subjected to the same pressure drop as the core plate. The core plate upset and faulted RIPDs are within the design basis. Therefore, the orificed fuel support remains qualified for the EPU.

Service Conditions	Pre-EPU RIPD, psi	EPU RIPD, psi	Design Basis RIPD, psi
Upset	23.49	24.77	26.0
Faulted	28.0	29.5	37.5

Fuel Channel

The fuel channels were assessed for the EPU-based pressure differentials across the channel wall. The fuel channel wall RIPDs (Reference 2, Appendix E, Tables 3-4 through 3-6) are within the design limits of the GE14 fuel assemblies for all service conditions.

Service Conditions	Pre-EPU RIPD, psi	EPU RIPD, psi	Design Basis RIPD, (w/GE14 Fuel) psi
Normal	10.9	11.05	11.05
Upset	13.8	13.95	13.95
Faulted	15.0	14.8	14.8

Steam Dryer

The results of the steam separator-dryer performance evaluation (Reference 2, Appendix E, Section 3.3.6) demonstrate that the steam separator-dryer performance remains acceptable up to some portion of extended power prior to any substantive hardware modification. To reduce the moisture content, hardware modifications are required. The structural integrity of the modified steam dryer is discussed in the response to Question 7.

Feedwater Sparger

The only change as a result of EPU is the change in the feedwater flow and temperature. The flow load has very minimal contribution to the original primary stress in the feedwater sparger. As an example, the maximum calculated normal load stress (which includes the flow load effects) is 3.99 Ksi, which is very small. This has an insignificant effect on the primary stress integrity of the component. The increase in feedwater temperature is approximately 16°F. Due to this increase in the inside temperature, the gradient across the wall actually becomes less severe, and therefore, effect of this change on fatigue is of no concern. Thus, the structural integrity of the feedwater sparger is maintained in the EPU condition.

Jet Pumps

The loads for the jet pump as affected by EPU are the hydraulic flow loads and the acoustic and flow induced lateral loads due to the postulated RLB LOCA. The seismic load remains unaffected by EPU. The increase in hydraulic flow through the jet pump riser is about 2%. Typical jet pump analyses have substantial margin to accommodate this marginal increase in the flow. In addition, the flow-induced and acoustic loads on the diffuser due to the postulated RLB LOCA are evaluated in combination with seismic effects. The maximum membrane and bending stress in the diffuser is 22,317 psi, which is within the faulted allowable of 60,840 psi. Thus, the structural integrity of the jet pump assembly and associated riser pipe and brace repairs is maintained in the EPU condition.

Core Spray Line & Sparger

The main contributors to the stresses in the core spray line are the secondary loads such as differential anchor displacement and thermal loads. The seismic loads are not affected by the EPU. The increase in annulus temperature due to EPU is about 2.3°F, per the recirculation system analysis. This is negligible for secondary load/stress concerns. The sparger inside the shroud is shielded from any possible minor increases in the flow due to the presence of the ledge that supports the top guide. Therefore, the core spray line and the sparger remain qualified for the EPU condition.

Access Hole Cover

The access hole cover is a bolted replacement of the original welded design for all units except DNPS Unit 2. The cover experiences the same RIPDs as the shroud support plate. The RIPDs are all within the bolted cover design basis pressure loading. The cover also experiences the RLB LOCA acoustic loading. The acoustic loading is applied as an equivalent pressure load. The resulting stress in the bolt increased from 70.5 Ksi to 80.125 Ksi in the faulted condition. The corresponding allowable stress is 159 Ksi, therefore, substantial margin exists. Thus the access hole cover remains qualified for EPU. Information for the access hole cover for DNPS Unit 2 will be provided separately.

Shroud Head & Steam Separator Assembly

The only applicable loading affected by the EPU is the differential pressure across the shroud head. The vertical combined loads based on the EPU RIPDs, in conjunction with the seismic vertical and horizontal loading (seismic loads remain unaffected by EPU), were recomputed and compared to the allowable shroud head bolt loads for the upset/emergency/faulted conditions. The following table summarizes EPU loads with maximum allowable.

Condition	Pre-EPU RIPD - psi	EPU RIPD - psi	EPU Bolt Load-Kips/bolt	Allowable Bolt Load-Kips/bolt
Upset	5.66	10.29	10.17	37.28
Faulted	18.3	24.5	16.49	74.56

It is determined that considerable margin remains with the EPU RIPDs. Thus the shroud head remains qualified for the EPU.

Incore Housings and Guide Tubes
These items are primarily affected by core flow loads, pressure, seismic loads, and thermal loads. There is no significant change in these loads as a result of EPU. The changes in the recirculation flow and temperature in the lower plenum are insignificant. Therefore, the loading basis for the incore housings and guide tubes have essentially not changed for EPU and the component remains qualified.

Question
3. In Section 3.3.5, you evaluated the effects of the EPU on the potential for flow-induced vibration of the reactor internal components due to the increase in steam produced (>20%) in the core, the increase in the core pressure drop, and the increase in the recirculation pump speed. You indicated that the evaluation was based on the vibration data for the reactor internal components recorded during the startup testing of DNPS and QCNPS plants and on operating experience from similar plants. The expected vibration levels under EPU conditions were estimated by extrapolating the vibration data recorded during startup testing at the DNPS and QCNPS units.

3A. Discuss whether and how the recorded vibration data can be applicable for your calculation of the flow induced vibration stress level after the steam separators and dryers hardware modifications that are required for the EPU.

3B. Provide a sample evaluation for the most critical components (i.e., steam dryers and steam separators) and the basis for using the operating experience of similar plants.

3C. Discuss the potential for flow-induced vibration of the reactor internal components due to various mechanisms, including, in particular, the fluid-elastic instability in the steam separators and dryers at the proposed power level. If the details of the analysis and the results are documented in a report, submit the report for staff review.

3D. Provide a discussion on the potential for excessive vibrations, high noise levels, and the instrument lines leakage that might be caused by the increased recirculation pump speed or flow for the proposed power uprate, as described in the NRC Information Notice 95-16.

Response
3A. There is no recorded vibration data for the steam dryer. It is a non-safety related component and it was not instrumented during startup. By analysis it was shown that the dryer natural frequencies do not change significantly with the addition of the hardware modification. Hence the modifications will have negligible effect on the dryer response. There were no modifications to the steam separator due to EPU.

3B. The steam dryer has no safety function. The sole function of the steam dryer is to remove moisture from the steam in order to minimize erosion of the piping and turbine and to improve the turbine efficiency. The Boiling Water Reactor Vessel Internals Project (BWRVIP) document BWRVIP-06 (Reference 3), which was endorsed by the NRC, also states that the dryer is non-safety related and failure of a dryer component may cause an operability concern but has no safety impact. Hence the dryer was not instrumented during startup testing and no measured vibration data is available for the prototype plant.

The design criteria for the steam dryer is that the structural integrity of the dryer is maintained when subjected to a steam line break occurring beyond the main steam isolation valves. Since the dome pressure is not changed under EPU conditions, steam dryer structural integrity evaluations performed for a steam line break for the current rated thermal power is applicable to EPU conditions.

During power uprate, the normal operation pressure drop through the dryer (0.56 psi) is less than 10% of the faulted condition value for main steam line break (6.0 psi). The dynamic pressure loads causing vibration are also of the same order of magnitude as the normal operation pressure drop. The steam dryer meets the design basis criteria for faulted conditions, which is more severe than normal operational conditions.

The operational history of steam dryers in similar plants was also studied to see if there were any flow induced vibration related problems in the dryer. Only drain channel cracks at steady state conditions and outer bank hood damage due to turbine stop valve (TSV) closure were found due to vibration effects. Drain channel cracking has occurred even during normal operation and is usually repaired after detection. The outer bank hoods adjacent to the steam outlet nozzles at DNPS and QCNPS are four times thicker than at the plant where the damage occurred, while the TSV closure time is identical. Hence it is expected that the outer bank hood can withstand the transient. While instances of drain channel cracking and hood cracking have occurred at operating plants, it is an operational issue only, relating to proper drying of the steam before it leaves the dryer. No structural integrity problems have been observed with these cracks. The dryers are visually inspected during removal in each refueling outage and any observed cracking can be repaired.

The steam separator is also not a safety-related component. However, the steam separator loads act on the shroud through the shroud head. Since the shroud is a safety related component, the separator/shroud structure was tested at various power conditions up to the rated power during plant startup. At DNPS Unit 2, four velocity sensors were installed at the separator to measure tangential motion. The maximum measured vibration was 15% of the allowable.

To assess whether or not the separator flow induced vibrations are acceptable during power uprate, it is necessary to determine how the excitation mechanisms change during power uprate. There are basically two sources of excitation, namely, flow turbulence and the periodic forces generated by the swirling motion of the flow through the separators. The magnitudes of the turbulence excitation change with the square of the separator velocity. Because there are no distinct peaks or valleys in the turbulence excitation spectrum, the separator, shroud head, and shroud assembly will vibrate at the structural system natural frequencies. Since the structural natural frequencies are not changed by higher steam flow rates, the vibration frequency will be the same irrespective of the power level. The higher steam flow rates corresponding to 117.8% of original licensed core thermal power will only result in higher vibration amplitudes at the structural natural frequencies.

For the periodic excitation forces, the magnitude increases with the square of the velocity while the forcing frequency increases linearly with the flow velocity. Examination of the response spectrum of the shroud/separator sensors shows that there is insignificant response at the calculated periodic forcing frequency of about 21.8 Hz. Thus it can be concluded that the shroud/separator vibration is mainly from flow turbulence. The above conclusion is used to determine the shroud/separator vibration amplitudes.

Separator flow velocity calculations show an increase of the maximum velocity by about 15.6% for the EPU condition as compared to the rated condition. Since the vibration amplitudes are expected to increase by the square of the separator inlet flow velocity, the vibration amplitudes are expected to increase by about 33.6%. Since the maximum vibration amplitude reached during startup testing of the Dresden plant was no more than 15% of the acceptance criteria, it can be readily concluded that shroud separator vibration amplitudes during power uprate will be within the acceptance criteria.

3C. The basic mechanisms of FIV in reactor internal components are due to (a) cross flow (b) turbulent parallel flow (c) forced vibration due to recirculation pump pulsation at the vane passing frequency and (d) motion dependent force excitation. Of all these mechanisms, only turbulence and forced vibration due to pump pulsation at the vane passing frequency have significant effects on BWR internal components. The effects of these depend on the location of the component and the flow. The characteristics of the responses have been determined by testing performed at development test facilities and at prototype reactors during initial startup. Based on years of testing, the only BWR reactor internal component which may be subjected to fluid-elastic instability is the jet pump. Development test data showed that under normal operating conditions there was no fluid elastic instability. It could occur under abnormal operating conditions, and it was shown that the instability is a direct function of the total core flow. Since the operating conditions are normal and the core flow is not changed for EPU conditions, jet pump vibration due to fluid -elastic instability effects are not anticipated.

3D. The vibration issue associated with increased containment noise and vibration levels due to increased recirculation pump speed was investigated and reported in GE SIL No. 600. The conclusion of this investigation was that the increased noise and vibration levels associated with higher recirculation pump speeds were a direct result of a residual heat removal (RHR) testable check valve not being properly seated. Testing demonstrated that the containment noise and

RHR vibration levels were greatly attenuated when the RHR testable check valve was properly seated.

The containment noise and vibration associated with the RHR testable check valve, at increased pump speeds and flow rates, was determined by testing to have no detrimental effect on plant equipment, including the reactor recirculation system (RRS) piping, RHR piping, the recirculation pumps and motors, and the containment structure.

Question

7. In Section 3.3.6, you stated that EPU conditions result in an increase in saturated steam generated in the reactor core. For constant core flow, this in turn results in an increase in the separator inlet quality and dryer face velocity and a decrease in the water level inside the dryer skirt, all of which affect the steam separator-dryer performance. The results of the evaluation demonstrate that the steam separator-dryer performance remains acceptable up to some portion of extended power prior to any substantive hardware modification. To reduce the moisture content, hardware modifications are required. These modifications will be completed before EPU implementation.

Confirm whether and how your evaluation in Section 3.3.4 for the structural integrity of steam separators and dryers will be affected by the required hardware modifications due to the proposed EPU at DNPS and QCNPS.

Response

Introduction

Evaluation for the DNPS and QCNPS EPU have concluded that the steam separator/dryer configurations for these plants are operating near their capabilities at pre-EPU conditions, and that higher main steam moisture content can be expected at EPU. A dryer modification will be implemented in order to limit the moisture in the main steam line to be no worse than current conditions; however, the design goal is less than or equal to 0.2% at EPU conditions. A perforated insert (1/8" thick) design will be used to reduce the moisture content by limiting the maximum local flow velocity through the steam dryer units (vanes).

Code and Safety Design Basis

The steam dryer is a non-safety class reactor internal component. Although the dryer does not perform a safety function, it is required not to generate loose parts when subjected to the design basis event like main steam line break outside the containment.

The steam dryers are not ASME Code items. However, the steam dryer and modification evaluations have used ASME Code Section III, Subsection NG, 1989 Edition for design qualification.

Structural Evaluation

Structural analyses were performed using ANSYS56D finite element computer code. Stress analyses with conservative load estimates showed that the perforated inserts, dryer structures, and the dryer support/RPV interface remain within the ASME Code stress limits for all service conditions. ANSYS56D is the computer program ANSYS Revision 5.6, which has been developed and is maintained by ANSYS, Inc. ANSYS56D is a large-scale general purpose finite element computer program. The code is a "Level - 2" GENE Quality Assurance program under controlled condition.

Dynamic analyses showed that the addition of the perforated inserts does not affect the dynamic characteristics of the dryer, and that the calculated frequency of the perforated inserts are essentially in the dryer support bracket seismic zero period acceleration range.

Structural evaluation were performed for the dryer, dryer modification (perforated inserts), and dryer support brackets for gravity, EPU pressures, seismic loads, and steam line breaks loads. The EPU pressure used in the analyses were the following values calculated for the modified dryer.

Service Levels	EPU Calculated dryer ΔP before modification, psi	EPU Calculated dryer ΔP after modification, psi
Normal	0.47	0.56
Upset	0.71	0.84
Faulted	5.40	6.00

Maximum stresses calculated for the dryer structures are compared with the ASME Code stress limits in the following table.

Service Level	Stress Category	Steam Dryer Mod –Ksi	Stress Allowable Ksi
Normal & Upset:			
	Pm	11.335	14.440
	Pm+Pb	12.587	21.660
Faulted:			
	Pm	31.327	34.656
	Pm+Pb	39.640	51.984

Question

10.A. In Section 3.5.5, you indicated that the main steam (MS) and feedwater (FW) piping will experience increased vibration levels, approximately proportional to the square of the flow velocities. For the proposed power uprate, the flow rates and flow velocities will increase by more than 20 percent of the flow rate at the original rated thermal power for the MS and FW piping systems.

Provide an evaluation of the cumulative fatigue usage factor (in addition to the startup and shutdown cycles), and the potential for flow-induced vibration in the MS and FW piping (during the normal and upset operations) and in heat exchangers following the power uprate.

10B. In Section 10.4.3, you indicated that the vibration level may even be higher if other flow induced vibration mechanisms occur.
Provide a discussion on the potential for flow-induced vibration of the main steam and feedwater piping due to various mechanisms, including, in particular, the fluid-elastic instability at the proposed power level.

Response
10A. The steady state flow induced vibration (FIV) maximum stress levels of the main steam (MS) and feedwater (FW) piping must remain below the endurance limit of the piping material. This is because many, many cycles of vibration will be encountered over the remaining design life of the plant. For austenitic (stainless) steel piping material, the mean value of endurance limit stress, at which high cycle fatigue failures can occur, is in the vicinity of 30,000 psi. The actual design fatigue endurance limit is set well below this value. The design fatigue endurance limit for steady state alternating stresses from vibration is 13,600 psi (zero to peak) for austenitic (stainless) steel piping materials. The design fatigue endurance limit for steady state alternating stresses from vibration is 7,690 psi (zero to peak) for carbon steel piping materials. These fatigue design endurance limits were taken from ASME Section III Pressure Vessel and Piping code and the American National Standard, OM S/G 1997.

If the steady state vibration levels of the MS and FW piping are measured and found to be below these design limits, which are well below the actual material fatigue endurance limits, then no fatigue usage can ever occur from FIV at the new and 20% higher flow rates. These 20% higher MS and FW flow rates are the flow rates required for EPU conditions.

The potential for flow-induced vibration of the main steam and feedwater piping due to various FIV mechanisms, such as a fluid-elastic instability, is possible. However, it is not possible to analytically predict which FIV mechanism, if any, may occur within the MS or FW piping at the new and higher MS and FW flow rates associated with the new EPU flow conditions. For this reason, Exelon Generation Company, LLC (EGC) will performing a startup piping vibration test program during initial plant operations during power ascension to the new EPU conditions. These new startup tests will show that the steady state MS and FW piping FIV levels at the new and higher EPU flow conditions are well below the fatigue endurance limit of the piping material.

Startup, shutdown, normal, and upset conditions or transient vibration cycles associated with the MS and FW piping are assessed in the piping evaluation report prepared for the planned EPU at the planned EPU flow conditions. MS and FW piping system are analyzed to the following codes.

- B31.1 Power Piping Code, 1967 edition
- B31.1 Power Piping Code, 1967 edition and 1973 through 1976 Summer Addenda.
- ASME Code Section III, Sub-section NC (Class 2), 1977 through 1978 Winter Addenda.
- ASME Code Section III, Sub-section ND (Class 3), 1974 through 1976 Summer Addenda.

These industry codes do not require fatigue analysis.

Heat exchangers in the main steam and feedwater systems, such as the main condenser and feedwater heaters, were evaluated for EPU operational conditions. Refer to the response to Questions 12C (Reference 1) and 12D (below) for discussions of these evaluations.

10B. In Section 10.4.3, it was stated that the vibration level may even be higher if other flow induced vibration mechanisms occur. The startup piping vibration test program planned for the MS and FW piping during initial plant operation at the new, higher EPU flow conditions, will be expected to show that the FIV levels are acceptable and well below the fatigue endurance limit of the piping material, independent of the FIV mechanism occurring.

Question
11D. Discuss the effects of the proposed power uprate on the pressure locking and thermal binding of safety-related power-operated gate valves for Generic Letter (GL) 95-07.

Response
11D. The results of GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," were determined to be unaffected by EPU as reported in Reference 4.

Question
12D. Provide a discussion on the potential for flow-induced vibration of the main condenser tubes, and heat exchangers due to increased temperature and flow in the main steam and feedwater systems.

Response
12D. For EPU, the range of circulating water flow rates through the main condenser tubes is unchanged. Flow-induced vibration for the main condenser tubes from steam is addressed in Question 12C as provided in Reference 1.

The feedwater heaters were analyzed and verified to be acceptable for the higher feedwater heater flows for EPU. The feedwater heaters maximum shell-side velocities were determined to be in compliance with the design guidelines of Heat Exchanger Institute, "Standard for Closed Feedwater Heaters," except for one heater group where the shell drain outlet velocity exceeded the allowable by less than 0.7 ft/sec. In addition, to assess the tube-side mechanical effect of EPU operation on the feedwater heaters, flow velocities were evaluated based on the heat exchange industry guidelines for tube side flow velocity to minimize tube end erosion. The maximum existing tube plugging in the heaters was considered. The tube-side flow velocities in all but one group of heaters are predicted to slightly exceed the guidelines, the highest by less than 3 ft/sec. These heaters have been identified for erosion monitoring.

Attachment A
Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation (Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References

1. Letter from K. A. Ainger (Commonwealth Edison Company) to U. S. NRC, "Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 8, 2000
2. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000
3. EPRI TR-105707, BWR Vessel and Internals Project, "Safety Assessment of BWR Reactor internals (BWRVIP-06)", dated October 1995
4. General Electric Company Licensing Topical Report, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32523P-A, Class III, February 2000, and Supplement 1, Volumes I and II

Attachment B
Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Affidavit for Withholding Portions of Attachment A from Public Disclosure

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General Electric Company

AFFIDAVIT

I, George B. Stramback, being duly sworn, depose and state as follows:

(1) I am Project Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Attachment 1 to letter GE-DQC–EPU-01-466, *Mechanical RAIs*, (GE Proprietary Information), dated August 7, 2001. The proprietary information is delineated by bars marked in the margin adjacent to the specific material in the Attachment 1, *GE Response to NRC Mechanical RAIs.*

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

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c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in both paragraphs (4)a. and (4)b., above.

(5) The information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains further details regarding the GE proprietary report NEDC-32961P, *Safety Analysis Report for Quad Cities 1 & 2 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, and NEDC-32962P, *Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, which contain detailed results of analytical models, methods and processes, including computer codes, which GE has

developed, obtained NRC approval of, and applied to perform evaluations of transient and accident events in the GE Boiling Water Reactor ("BWR").

The development and approval of these system, component, and thermal hydraulic models and computer codes was achieved at a significant cost to GE, on the order of several million dollars.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GE asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GE would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

George B. Stramback, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 7th day of August 2001.

George B. Stramback
General Electric Company

Subscribed and sworn before me this 7th day of August 2001.

TERRY J. MORGAN
Commission # 1304914
Notary Public - California
Santa Clara County
My Comm. Expires May 18, 2005

Notary Public, State of California

Attachment C
Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-proprietary version)

J81

Attachment C
Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 1, 2, 3, 7, 10, 11D, and 12D. Responses to NRC Questions 4, 5, 6, 8, 9, 11, (Parts A, B, C, and E), 12 (Parts A, B, and C), 13, and 14 were provided in a previous transmittal (Reference 1).

Question

2. In reference to Section 3.3.4 for the reactor internal structural evaluation, you stated that the structural assessment used guidelines and procedures similar to those in the design basis analyses. All applicable service levels, namely normal, upset, emergency, and faulted are considered consistent with the current design basis analyses. The loads considered in the evaluation include the reactor internal pressure differences, seismic loads, flow induced and acoustic loads due to the postulated recirculation line break (RLB-LOCA), thermal load effects, dead weight, and flow loads.

1A. Confirm whether the loads considered for the evaluation of the reactor internal components include the fuel lift loads, the safety relief valve discharge loads, annulus asymmetric pressurization and jet reaction loads during a main steam or a feedwater line break.

1B. Discuss the effects of the proposed extended power uprate (EPU) on the RLB-LOCA load and other design basis loads mentioned above.

Response

1B. The effects of EPU on the loads considered for the core support structure and non-core support structure components are discussed in detail for each component in Section 3.3.4 (a) through (o) of Reference 2, Attachment E, Power Uprate Safety Analysis Report (PUSAR). Governing loads and stresses of reactor internals components are provided in the response to Question 2B.

Question

2A. In Section 3.3.2, you indicated that the reduction in some fatigue usage factors (CUFs) in Table 3-3a is a result of reduction in the conservatism and/or number of thermal cycles from the original analysis. Describe how you arrived at an accurate representation of the fatigue cycles which resulted in a reduction of CUF from 0.94 to 0.862 for the shroud support as provided in Table 3-3a.

2B. In regard to Section 3.3.4, provide the maximum calculated stress and CUFs for the reactor internal components evaluated for both the current design condition and the uprate power condition, the allowable code limits, and the code and code edition used in the evaluation for the power uprate. If different from the code of record, provide your justification.

Response

2A. The EPU CUF of 0.862 for the support skirt was reduced by removing conservatism from a previous analysis (CUF = 0.945). The 1989 analysis used 278 startup/shutdown cycles and 361

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scram cycles. The support skirt was re-analyzed in 2000 to account for the then-current thermal cycle information; using 250 startup/shutdown cycles and 232 scram cycles (CUF = 0.838). The power uprate calculation used this information to scale up the CUF to 0.862. Consequently, the power uprate fatigue usage was an increase in CUF from the 2000 CUF of 0.838 to 0.862.

Scaling Technique

General Electric has developed a technique to conservatively scale the original stress report stresses to account for changes in the original pressures, temperatures, and nozzle flows as a result of EPU.

Many pressure vessel calculations select the three stress directions of the orthogonal coordinate system such that the shear stress components are zero; the normal stress components are the principal stresses. With this orientation, the pressure stresses are directly proportional to the increase in coolant pressure, and the magnitude of the principal stress resulting from thermal cycling is proportional to the temperature change during a thermal transient. When there are no changes in mechanical loads as a result of the EPU, the new magnitude of the principal stress is:

$\sigma_{new} = \sigma_p * (P_{new}/P_{old}) + \sigma_t * (\Delta t_{new}/\Delta t_{old}) + \sigma_m$

where:

σ_p = Original pressure stress
σ_t = Original thermal stress
σ_m = Original mechanical stress
P_{new} = EPU pressure
P_{old} = Original pressure
Δt_{new} = EPU temperature range
Δt_{old} = Original temperature range

or:

$\sigma_{new} = \sigma_p * SCF_p + \sigma_t * SCF_t + \sigma_m$

where:

SCF_p = Pressure stress scaling factor
SCF_t = Thermal stress scaling factor

Components that experience a change in internal coolant flow during operation have a flow scaling factor, SCF_f. The magnitude of the internal flow changes the convective heat transfer coefficient. The Biot Modulus is used to determine the effect of increased nozzle flows on the nozzle thermal skin stresses. It can be shown that:

$B_i \; \alpha \; h \; \alpha \; V^{0.8}$

where:

B_i = Biot Modulus, hL/k
h = Film convection coefficient
V = Flow velocity through nozzle

This relationship allows the flow scaling factor to be determined by the following:

$$SCF_f = (V_{new}/V_{old})^{0.8}$$

When the flow scaling factor is applied, a new thermal SCF is calculated using both the SCF_t and the SCF_f. The new thermal scaling factor is calculated using the following formula:

$$SCF_T = SCF_t * SCF_f$$

Most stress reports do not separately report the pressure, thermal, and mechanical stresses; therefore, it is not practical to calculate the scaled pressure or scaled thermal stresses. A conservative scaling technique, using the larger of the pressure and temperature scaling factors, is used to scale the entire stress magnitude. If a calculated SCF is less than unity, a SCF = 1.0 is used instead. This method is a conservative alternative to scaling the individual stress components because:

- The largest scaling factor is used for both the pressure and temperature SCF.
- The mechanical stresses are increased by the SCF even though the design mechanical loads did not increase.
- Conditions which generate a stress reduction (a SCF less than 1.0) are ignored.

The stress scaling technique may be further simplified by applying the SCF to the stress intensity alone, rather than applying the SCF to the principal stress components. A stress intensity, or stress difference, used to compare with the American Society of Mechanical Engineers (ASME) Code allowable values is determined by selecting the absolute value of the maximum difference between any pair of principal stresses. Consider the following example:

$$\begin{aligned} S_{12,new} &= \sigma_{1,new} - \sigma_{2,new} \\ &= \sigma_{1,old} * SCF - \sigma_{2,old} * SCF \\ &= (\sigma_{1,old} - \sigma_{2,old}) * SCF \\ &= S_{12,old} * SCF \end{aligned}$$

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Scaling Factors for the Support Skirt

The support skirt is located in Region B of the reactor and only experienced a change in temperature due to EPU conditions. Based on the scale factor equations discussed above, the highest normal startup SCF is 1.002 and the highest SCRAM SCF is 1.083.

Scaling Factors for Region B

		Pre- Power Uprate Condtions		Power Uprate Conditions		Scaling Factor
Zones	Description	Initial Temperature, F	Final Temperature, F	Initial Temperature, F	Final Temperature, F	SCF_1
3 – 4	Normal Startup	100	546	100	547	1.002
4 – 5	Normal Startup	546	538	547	539	1.000
4 – 5	Normal Startup	538	520	539	530	0.500
10 – 11	Scram	400	520	400	530	1.083

Support Skirt

The support skirt was re-analyzed in 1989 and accounted for the latest thermal cycle information at that time. Since the QCNPS and DNPS RPVs have the same usage factors, the QCNPS results apply to DNPS. The limiting transients for the support skirt are heatup and cooldown. The maximum primary plus secondary stress range (P + Q) is 82.88 Ksi which exceeds the Code allowable limit of $3S_m$. The P + Q stress intensity with thermal bending removed is scaled up by using the appropriate SCF and compared to the Code allowable.

$P + Q = (P + Q - \text{Thermal Bending})_{old} * SCF$
$54.41\ \text{Ksi} = 53.31\ \text{Ksi} * 1.002$
$54.41\ \text{Ksi} < 3S_m = 69.9\ \text{Ksi}$

Since the calculated value of the maximum primary plus secondary stress is greater than the $3S_m$ limit, an elastic-plastic analysis, as described in the Code is performed.

$S_{alt,new} = S_{P+Q+F} / 2 = [(S_n * SCF*(K_t - 1) + S_{surf} * SCF)/2]*K_e*(E_c/E_a)$
$= [(82.88*1.002*(2.12-1)+117.77*1.002)/2]*1.15*(30/28)$
$= 130.0$ Ksi.

where: $K_e = 1.0$ for $S_n \leq 3S_m$
$= 1.0 + [(1/n - 1)/(m - 1)]*(S_n/3S_m - 1) = 1.15$
for $3S_m < S_n < 3mS_m$
$= 1/n$, for $S_n > 3mS_m$

where:

$n = 0.2$ for Low Alloy Steel
$m = 2.0$ for Low Alloy Steel
$3S_m = 80.1$ Ksi
$S_n = P + Q = 82.88$ Ksi

S_{surf} = 117.77 Ksi
E_c = 30E6 psi
E_a = 28E6 psi
K_t = 2.12
SCF = 1.002 (Region B, Startup)

A thermal stress ratcheting check was performed and shakedown will occur. Therefore, thermal stress ratcheting is not a concern. For an alternating stress of 130.0 Ksi, the allowable number of cycles is 304. For a total number of startup/shutdown cases of 250, the fatigue usage factor is 0.822. Similarly, for SCRAM, the alternating stress was calculated using the above method with a SCF of 1.083 and is 45.5 Ksi. This stress allows 5860 SCRAM cycles. There are 232 SCRAM cases predicted for a 40 year life which gives a fatigue usage factor of .040. The total combined fatigue usage factor is:

$U_{Total} = U_{SU/SD} + U_{SCRAM}$
$U = n_1/N_1 + n_2/N_2 = 250/304 + 232/5860 = .822 + .040 = .862 < 1.0$

<u>Question</u>

3. In Section 3.3.5, you evaluated the effects of the EPU on the potential for flow-induced vibration of the reactor internal components due to the increase in steam produced (>20%) in the core, the increase in the core pressure drop, and the increase in the recirculation pump speed. You indicated that the evaluation was based on the vibration data for the reactor internal components recorded during the startup testing of DNPS and QCNPS plants and on operating experience from similar plants. The expected vibration levels under EPU conditions were estimated by extrapolating the vibration data recorded during startup testing at the DNPS and QCNPS units.

3A. Discuss whether and how the recorded vibration data can be applicable for your calculation of the flow induced vibration stress level after the steam separators and dryers hardware modifications that are required for the EPU.

3B. Provide a sample evaluation for the most critical components (i.e., steam dryers and steam separators) and the basis for using the operating experience of similar plants.

3C. Discuss the potential for flow-induced vibration of the reactor internal components due to various mechanisms, including, in particular, the fluid-elastic instability in the steam separators and dryers at the proposed power level. If the details of the analysis and the results are documented in a report, submit the report for staff review.

3D. Provide a discussion on the potential for excessive vibrations, high noise levels, and the instrument lines leakage that might be caused by the increased recirculation pump speed or flow for the proposed power uprate, as described in the NRC Information Notice 95-16.

Response

3A. There is no recorded vibration data for the steam dryer. It is a non-safety related component and it was not instrumented during startup.

There were no modifications to the steam separator due to EPU.

3B. The steam dryer has no safety function. The sole function of the steam dryer is to remove moisture from the steam in order to minimize erosion of the piping and turbine and to improve the turbine efficiency. The Boiling Water Reactor Vessel Internals Project (BWRVIP) document BWRVIP-06 (Reference 3), which was endorsed by the NRC, also states that the dryer is non-safety related and failure of a dryer component may cause an operability concern but has no safety impact. Hence the dryer was not instrumented during startup testing and no measured vibration data is available for the prototype plant.

The design criteria for the steam dryer is that the structural integrity of the dryer is maintained when subjected to a steam line break occurring beyond the main steam isolation valves. Since the dome pressure is not changed under EPU conditions, steam dryer structural integrity evaluations performed for a steam line break for the current rated thermal power is applicable to EPU conditions.

The operational history of steam dryers in similar plants was also studied to see if there were any flow induced vibration related problems in the dryer. Only drain channel cracks at steady state conditions and outer bank hood damage due to turbine stop valve (TSV) closure were found due to vibration effects. Drain channel cracking has occurred even during normal operation and is usually repaired after detection. The outer bank hoods adjacent to the steam outlet nozzles at DNPS and QCNPS are four times thicker than at the plant where the damage occurred, while the TSV closure time is identical. Hence it is expected that the outer bank hood can withstand the transient. While instances of drain channel cracking and hood cracking have occurred at operating plants, it is an operational issue only, relating to proper drying of the steam before it leaves the dryer. No structural integrity problems have been observed with these cracks. The dryers are visually inspected during removal in each refueling outage and any observed cracking can be repaired.

The steam separator is also not a safety-related component. However, the steam separator loads act on the shroud through the shroud head. Since the shroud is a safety related component, the separator/shroud structure was tested at various power conditions up to the rated power during plant startup.

3C.

3D. The vibration issue associated with increased containment noise and vibration levels due to increased recirculation pump speed was investigated and reported in GE SIL No. 600. The conclusion of this investigation was that the increased noise and vibration levels associated with higher recirculation pump speeds were a direct result of a residual heat removal (RHR) testable check valve not being properly seated. Testing demonstrated that the containment noise and RHR vibration levels were greatly attenuated when the RHR testable check valve was properly seated.

The containment noise and vibration associated with the RHR testable check valve, at increased pump speeds and flow rates, was determined by testing to have no detrimental effect on plant equipment, including the reactor recirculation system (RRS) piping, RHR piping, the recirculation pumps and motors, and the containment structure.

Question
7. In Section 3.3.6, you stated that EPU conditions result in an increase in saturated steam generated in the reactor core. For constant core flow, this in turn results in an increase in the separator inlet quality and dryer face velocity and a decrease in the water level inside the dryer skirt, all of which affect the steam separator-dryer performance. The results of the evaluation demonstrate that the steam separator-dryer performance remains acceptable up to some portion of extended power prior to any substantive hardware modification. To reduce the moisture content, hardware modifications are required. These modifications will be completed before EPU implementation.
Confirm whether and how your evaluation in Section 3.3.4 for the structural integrity of steam separators and dryers will be affected by the required hardware modifications due to the proposed EPU at DNPS and QCNPS.

Response

Question
10.A. In Section 3.5.5, you indicated that the main steam (MS) and feedwater (FW) piping will experience increased vibration levels, approximately proportional to the square of the flow velocities. For the proposed power uprate, the flow rates and flow velocities will increase by more than 20 percent of the flow rate at the original rated thermal power for the MS and FW piping systems.
Provide an evaluation of the cumulative fatigue usage factor (in addition to the startup and shutdown cycles), and the potential for flow-induced vibration in the MS and FW piping (during the normal and upset operations) and in heat exchangers following the power uprate.

10B. In Section 10.4.3, you indicated that the vibration level may even be higher if other flow induced vibration mechanisms occur.
Provide a discussion on the potential for flow-induced vibration of the main steam and feedwater piping due to various mechanisms, including, in particular, the fluid-elastic instability at the proposed power level.

Response

10A. The steady state flow induced vibration (FIV) maximum stress levels of the main steam (MS) and feedwater (FW) piping must remain below the endurance limit of the piping material. This is because many, many cycles of vibration will be encountered over the remaining design life of the plant. For austenitic (stainless) steel piping material, the mean value of endurance limit stress, at which high cycle fatigue failures can occur, is in the vicinity of 30,000 psi. The actual design fatigue endurance limit is set well below this value. The design fatigue endurance limit for steady state alternating stresses from vibration is 13,600 psi (zero to peak) for austenitic (stainless) steel piping materials. The design fatigue endurance limit for steady state alternating stresses from vibration is 7,690 psi (zero to peak) for carbon steel piping materials. These fatigue design endurance limits were taken from ASME Section III Pressure Vessel and Piping code and the American National Standard, OM S/G 1997.

If the steady state vibration levels of the MS and FW piping are measured and found to be below these design limits, which are well below the actual material fatigue endurance limits, then no fatigue usage can ever occur from FIV at the new and 20% higher flow rates. These 20% higher MS and FW flow rates are the flow rates required for EPU conditions.

The potential for flow-induced vibration of the main steam and feedwater piping due to various FIV mechanisms, such as a fluid-elastic instability, is possible. However, it is not possible to analytically predict which FIV mechanism, if any, may occur within the MS or FW piping at the new and higher MS and FW flow rates associated with the new EPU flow conditions. For this reason, Exelon Generation Company, LLC (EGC) will performing a startup piping vibration test program during initial plant operations during power ascension to the new EPU conditions. These new startup tests will show that the steady state MS and FW piping FIV levels at the new and higher EPU flow conditions are well below the fatigue endurance limit of the piping material.

Startup, shutdown, normal, and upset conditions or transient vibration cycles associated with the MS and FW piping are assessed in the piping evaluation report prepared for the planned EPU at the planned EPU flow conditions. MS and FW piping system are analyzed to the following codes.

- B31.1 Power Piping Code, 1967 edition
- B31.1 Power Piping Code, 1967 edition and 1973 through 1976 Summer Addenda.
- ASME Code Section III, Sub-section NC (Class 2), 1977 through 1978 Winter Addenda.
- ASME Code Section III, Sub-section ND (Class 3), 1974 through 1976 Summer Addenda.

These industry codes do not require fatigue analysis.

Heat exchangers in the main steam and feedwater systems, such as the main condenser and feedwater heaters, were evaluated for EPU operational conditions. Refer to the response to Questions 12C (Reference 1) and 12D (below) for discussions of these evaluations.

10B. In Section 10.4.3, it was stated that the vibration level may even be higher if other flow induced vibration mechanisms occur. The startup piping vibration test program planned for the MS and FW piping during initial plant operation at the new, higher EPU flow conditions, will be expected to show that the FIV levels are acceptable and well below the fatigue endurance limit of the piping material, independent of the FIV mechanism occurring.

Question
11D. Discuss the effects of the proposed power uprate on the pressure locking and thermal binding of safety-related power-operated gate valves for Generic Letter (GL) 95-07.

Response
11D. The results of GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," were determined to be unaffected by EPU as reported in Reference 4.

Question
12D. Provide a discussion on the potential for flow-induced vibration of the main condenser tubes, and heat exchangers due to increased temperature and flow in the main steam and feedwater systems.

Response
12D. For EPU, the range of circulating water flow rates through the main condenser tubes is unchanged. Flow-induced vibration for the main condenser tubes from steam is addressed in Question 12C as provided in Reference 1.

The feedwater heaters were analyzed and verified to be acceptable for the higher feedwater heater flows for EPU. The feedwater heaters maximum shell-side velocities were determined to be in compliance with the design guidelines of Heat Exchanger Institute, "Standard for Closed Feedwater Heaters," except for one heater group where the shell drain outlet velocity exceeded the allowable by less than 0.7 ft/sec. In addition, to assess the tube-side mechanical effect of EPU operation on the feedwater heaters, flow velocities were evaluated based on the heat exchange industry guidelines for tube side flow velocity to minimize tube end erosion. The maximum existing tube plugging in the heaters was considered. The tube-side flow velocities in all but one group of heaters are predicted to slightly exceed the guidelines, the highest by less than 3 ft/sec. These heaters have been identified for erosion monitoring.

Attachment C
Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation (Non-Proprietary)
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References

1. Letter from K. A. Ainger (Commonwealth Edison Company) to U. S. NRC, "Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated August 8, 2000

2. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

3. EPRI TR-105707, BWR Vessel and Internals Project, "Safety Assessment of BWR Reactor internals (BWRVIP-06)", dated October 1995

4. General Electric Company Licensing Topical Report, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32523P-A, Class III, February 2000, and Supplement 1, Volumes I and II

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RS-01-157

August 8, 2001

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D.C. 20555-0001

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Additional Mechanical Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

Reference: Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

In the referenced letter, Commonwealth Edison (ComEd) Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications (TS) for Dresden Nuclear Power Station (DNPS), Units 2 and 3, and Quad Cities Nuclear Power Station (QCNPS), Units 1 and 2, to allow operation with an extended power uprate (EPU). In a July 23, 2001, teleconference between members of the NRC and representatives of EGC, the NRC requested additional information regarding these proposed changes. Attachment A to this letter provides the requested information. This letter provides the first portion of the requested information. The remainder of the requested information will be provided in a separate letter.

Some of the information in Attachment A is proprietary information to the General Electric Company, and EGC requests that it be withheld from public disclosure in accordance with 10 CFR 2.790(a)(4), "Public Inspections, Exemptions, Requests for Withholding." This information is indicated with sidebars. Attachment B provides the affidavit supporting the request for withholding the proprietary information in Attachment A from public disclosure, as required by 10 CFR 2.790(b)(1). Attachment C contains a non-proprietary version of Attachment A.

Should you have any questions concerning this letter, please contact Mr. A. R. Haeger at (630) 657-2807.

Respectfully,

for Terrence W. Simpkins
K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Attachments:

Affidavit
Attachment A: Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Proprietary version)
Attachment B: Affidavit for Withholding Portions of Attachment A from Public Disclosure
Attachment C: Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (Non-proprietary version)

cc: Regional Administrator - NRC Region III
NRC Senior Resident Inspector - Dresden Nuclear Power Station
NRC Senior Resident Inspector - Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety - Illinois Department of Nuclear Safety

bcc: NRC Project Manager, NRR - Dresden Nuclear Power Station, Units 2 and 3
NRC Project Manager, NRR – Quad Cities Nuclear Power Station, Units 1 and 2
Manager of Energy Practice - Winston and Strawn
Director-Licensing, Mid-West Regional Operating Group
Manager-Licensing, Dresden and Quad Cities Stations
Regulatory Assurance Manager - Dresden Nuclear Power Station
Regulatory Assurance Manager – Quad Cities Nuclear Power Station
D. Tubbs – MidAmerican Energy Company
W. Leech – MidAmerican Energy Company
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Document Control Desk - Licensing (Electronic Copy)

STATE OF ILLINOIS)
COUNTY OF DUPAGE)
IN THE MATTER OF)
EXELON GENERATION COMPANY, LLC) Docket Numbers
DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3) 50-237 AND 50-249
QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2) 50-254 AND 50-265

SUBJECT: Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation, Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

Terrence W. Simpkin
T. W. Simpkin
Manager – Licensing

Subscribed and sworn to before me, a Notary Public in and

for the State above named, this 8th day of

August, 20 01.

Notary Public

"OFFICIAL SEAL"
Timothy A. Byam
My Commission Expires 11/24/2001

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 4, 5, 6, 8, 9, 11 (Parts A, B, C, and E), 12 (Parts A, B, and C), 13, and 14. Responses to NRC Questions 1, 2, 3, 7, 10, 11D, and 12D will be provided separately.

Question

4. A. In reference to Sections 3.3.2 and 3.3.4, provide a discussion of the methodology, assumptions and loading combinations used for evaluating the reactor vessel and internal components with regard to the stresses and fatigue usage for the power uprate.

B. Were the analytical computer codes used in the evaluation different from those used in the original design-basis analysis? If so, identify the new codes used and provide your justification for their use by specifying how were these codes benchmarked for such applications.

Response

A. The methodology, assumptions and loading combinations used for evaluating the reactor vessel and internal components are described in Reference 1, Appendix I, "Methods and Assumptions for Vessel and Components Evaluations."

B. As noted in Reference 2, Power Uprate Safety Analysis Report (PUSAR), Table 1-3, "Computer Codes Used for EPU," the SAP4G07V program was used to perform the structural and dynamic load analysis for the shroud and seismic evaluation with GE14 fuel. The SAP4G07V program is a general purpose finite elements program. The same computer code was used in the original analysis.

Question

5. In Section 4.1.2.3 regarding the subcompartment pressurization, you stated that the increase in actual asymmetrical loads on the vessel, attached piping and biological shield wall, due to the postulated main steam and feedwater pipe breaks in the annulus between the reactor vessel and biological shield wall is minor. You also indicated that the biological shield wall and component designs remain adequate, because there is sufficient pressure margin available.

Discuss quantitatively how will the biological shield wall and the reactor vessel and internals be affected by the proposed power uprate as a result of increase in the applied asymmetrical pressurization and jet loads.

Response

PUSAR Section 4.1.2.3, "Subcompartment Pressurization," discusses asymmetrical loads without specifically referring to a main steam or feedwater line break. A postulated rupture of a recirculation suction line was previously evaluated for both Dresden Nuclear Power Station (DNPS) and Quad Cities Nuclear Power Station (QCNPS) to assess the structural capability of the biological shield wall.

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For both DNPS and QCNPS, the largest line which has the safe end located in the annulus region between the reactor vessel and the biological shield wall is a 4 inch jet pump instrument line. The maximum calculated wall differential pressure (i.e., 1 psid) for this postulated break is well below the structural capability of the wall.

These previous evaluations were used as a basis to quantify the changes expected due to EPU. A simplified subcompartment pressurization model of the DNPS and QCNPS annulus region was developed and expected mass and energy releases at pre-EPU and EPU conditions were determined.

Recirculation suction line break mass and energy releases at pre-EPU and EPU conditions were calculated using the standard General Electric (GE) methods, using inputs from the reactor heat balances at both pre-EPU and EPU conditions.

The following assumptions were used to determine the pre-EPU and EPU mass and energy releases.

- Initial mass release rates (i.e., inventory period) are based on Moody saturated critical flow, with a flow multiplier of 1, through the break area from both the pipe side and reactor side of the break.
- Energy release rates are based on the core inlet enthalpy.
- After the initial blowdown (i.e., inventory period) the flow is conservatively based on the Henry-Fauske subcooled critical flow, rather than the Moody subcooled critical flow, from the nozzle area on the reactor side of the break. The flow from the pipe side of the break is based on the total area of 10 jet pump nozzles plus the reactor water clean up (RWCU) line area.
- The safe end weld is within the biological shield wall penetration. This penetration is included in the evaluation to account for a flow split between the annulus and the drywell.

The resulting maximum incremental increase in mass release due to EPU was determined to be 6% for DNPS and 6.2% for QCNPS. The maximum incremental increase in energy release due to EPU was determined to be 5.5% for DNPS and 5.8% QCNPS.

Benchmark subcompartment pressurization analyses of the DNPS and QCNPS annulus region were performed using the COMPARE computer code and pre-EPU mass and energy releases for a recirculation suction line break. The same model was rerun using mass and energy releases calculated at EPU conditions.

The biological shield wall pressurization has been evaluated for the effects of these small increases in mass and energy. An analysis was performed to determine the effect on annulus pressure expected for the above changes in mass and energy releases. This resulted in a minor reduction in pressure margin. The study resulted in an increase of 0.9 psi for DNPS and 1.2 psi for QCNPS in the maximum calculated biological shield wall differential pressure. The incremental increase in annulus pressure was applied to results of the previous evaluations dicussed above. The pressure margins are provided below.

PARAMETER	DNPS	QCNPS
Annulus differential pressure at which biological shield wall failure would begin (psid)	41	46
Maximum annulus pressure from a recirculation line break (psid)	36	38
Pre-uprate margin (psid)	5	8
Incremental change due to EPU (psi)	0.9	1.2
EPU margin (psid)	4.1	6.8

The jet loads are evaluated in PUSAR Section 10.1.2, "Pipe Whip and Jet Impingement." The review shows that there is no change in the operating pressure of high energy main steam piping. Thus, the jet impingement load evaluation results remain unchanged for the main steam piping system due to EPU. For the feedwater piping, the internal pressure increase is less than 10 psi. The less than 10 psi change in the internal pressure represents an approximately 1% change that was judged to be insignificant for jet impingement load evaluation.

Question

6. In the evaluation of the reactor jet pumps in Section 3.3.4, you stated that additional engineering evaluations will be performed to determine if the jet pump riser brace will be susceptible to vibration from the recirculation pump vane passing frequency (VPF). The evaluations will determine if modifications are required to alter the natural frequency of the jet pump braces.

A. Provide your evaluation associated with the possible VPF vibrations due to the EPU.

B. Confirm whether and how your evaluation for the structural integrity of jet pumps will be affected by the VPF vibrations due to EPU at DNPS and QCNPS.

Response

A. An extensive test program was conducted at the GE test facilities in San Jose from February to July 2001 to determine the natural frequencies of the DNPS Unit 2 and Unit 3 riser braces. The DNPS Unit 3 riser braces are representative of the QCNPS Units 1 and 2 riser braces. A full scale mockup of the jet pump riser pipe and riser brace was constructed and set up to determine the residual loads and natural frequencies of the riser brace leaves in air and also while submerged under water. A total of 26 strain gages and 6 accelerometers were installed and the natural frequencies of these jet pump components were computed from the dynamic response to impacts from an instrumented hammer. The results of the test program showed that the reactor recirculation system VPF during EPU operation is well removed from the riser brace natural frequencies and no modifications are required to alter the natural frequency of the riser braces.

B. The VPF vibrations at non-resonant conditions were considered in the evaluation of the jet pumps. The above described test was conducted to see if there is any potential for resonance of the riser brace leaves due to VPF at EPU conditions. Since the VPF is well removed from the riser brace leaf natural frequency, the response due to VPF is small and the existing evaluation is not affected.

Question

8. A. In reference to Section 3.5, provide a discussion of the methodology and assumptions used for evaluating the reactor coolant pressure boundary piping systems for the proposed power uprate.

B. Provide the calculated maximum stresses and fatigue usage factors at the current design basis and the proposed power uprate conditions, corresponding critical locations and piping systems, allowable stress limits, and the code and code edition used in the evaluation for the power uprate. If different from the Code of record, justify and reconcile the differences.

Response

A. The reactor coolant pressure boundary (RCPB) piping evaluated includes the following piping systems.

- Reactor recirculation (RR) system
- Main steam (MS) piping inside containment
- Branch piping from RR and MS systems, including safety and relief valve discharge lines, shutdown cooling system (residual heat removal (RHR) for QCNPS), RWCU, low pressure coolant injection (LPCI), and others
- Reactor pressure vessel (RPV) head vent, RPV bottom drain line, and/or isolation condenser (IC) (Reactor Core Isolation Cooling (RCIC) for QCNPS)
- MS drain lines
- Small bore piping attached to these systems

Existing design and licensing basis documents, such as design specifications and piping stress reports, were reviewed to determine the design and analytical basis for these piping systems. The proposed uprate parameters of the RCPB piping systems were compared with the existing analytical bases to determine any increases in temperature, pressure, and flow due to the uprate conditions. During the evaluation process, the original code of record, code allowables, and the same analytical techniques were used. No new assumptions or computer codes were used except for in the evaluation of the MS lines as described in the response to Question 13A.

For the majority of these systems, it was determined that there are no changes in the analysis parameters. The RR system was determined to be subject to a slight increase in temperature, but less than the acceptance criteria outlined in the response to Question 9A. The MS piping will not experience an increase in temperature. However, a significant increase in flow will be seen, which will have an impact on the turbine stop valve (TSV) closure transient. A detailed description of the methodology and assumptions used in the evaluation of the MS system is provided in the response to Question 13A. Some of the branches off the RCPB piping (i.e., core spray (CS), LPCI, etc.) were also found to experience temperature increases due to long term post-LOCA conditions in which water is being drawn from the suppression pool (i.e., torus). These systems were evaluated with the large bore torus water piping systems and the methodology and assumptions used in those evaluations are described in the response to Question 9A. All other RCPB piping systems are either not impacted by EPU, or the changes are within acceptance criteria.

B. The majority of the RCPB piping systems are designed to American National Standards Institute (ANSI) B31.1.0, 1967 requirements, which are not subject to fatigue requirements. In addition, the RCPB piping is under the jurisdiction of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section I, 1965 Edition, through Summer 1966 Addenda including Code Cases N-1 thru N-3 and N-7 thru N-11. In accordance with these codes and code cases, fatigue is not part of the design or licensing basis for these systems. For DNPS only, the one exception is the RR system piping for DNPS Unit 3, which was replaced in the mid 1980s. The stress analysis for Class I piping covered by the scope of the RR pipe replacement project was performed in accordance with ASME Code, Section III, Subsection NB, 1980 Edition, including the Summer 1982 Addenda, which includes fatigue requirements. The RR system piping was determined to have a only minor increase in the temperature, which was considered negligible. Any small increase in stresses due to the slight temperature increase is bounded by inherent conservatisms in the existing analysis. Therefore, the calculated maximum stresses and fatigue usage factors are unchanged as a result of the proposed uprate. The critical locations and piping systems, allowable stress limits, and the code and code edition used are also unchanged.

Question
9.A. Provide a summary of your evaluation of the pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers and anchors at the power uprate condition. The evaluation should include the methodology, assumptions, and the results of evaluation for the critical piping systems affected by the proposed power uprate.

B. Were the analytical computer codes used in the evaluation different from those used in the original design-basis analysis? If so, identify the new codes and provide your justification for their use by specifying how these codes were benchmarked for such applications.

Response
A. Operation at EPU conditions may increase piping stresses caused by higher operating temperatures, pressures and flow rates. Additionally, piping components (i.e., pipe supports, equipment nozzles, etc.) may be potentially subjected to increased loadings due to the EPU.

The piping system evaluations for power uprate were performed by determining "change factors" for the changes in thermal, pressure, flow rate, and total design load conditions. This

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method is based on determining a "change factor" by conservatively comparing the ratio of power uprate temperature, pressure and flow conditions to the corresponding pre-EPU conditions. The method (described below) used to evaluate DNPS and QCNPS is the same method used on several other power uprates - most recently for the Turkey Point, Byron and Braidwood power uprates. The recent Byron and Braidwood NRC Safety Evaluation for power uprate (Reference 3) concluded that, "The staff finds the methodology to be acceptable considering the conservatism in the calculation of the scaling factors for the power uprate stress and loads."

This method is based on determining a "change factor" by conservatively comparing the ratio of power uprate temperature, pressure and flow conditions to the corresponding pre-uprate conditions.

Where the "change factor" is less than or equal to 1.0, the pre-EPU (i.e., existing) conditions envelop or equal the power uprate conditions and no further review is performed.

For minor changes resulting in a "change factor" between 1.0 and 1.05 (i.e., 5%), the increase was considered acceptable since the small increase is offset by conservatism inherent in the analytical methods used to calculate the existing stresses and loads. The conservatism include, but are not limited to, the industry practice of enveloping multiple operating conditions and modeling pipe supports without consideration of gaps between piping and supports. Pressure effects are considered in conjunction with other loading conditions which are unchanged by the EPU (e.g., weight, seismic) thus the overall effect of the pressure change factor is reduced. Therefore for "change factors" between 1.0 and 1.05, the existing stress and load values were considered to be acceptable and remain within allowable limits.

For "change factors" greater than 1.05, simple and conservative evaluations were performed to address the specific increase in stress and load values. Where the simple evaluation yielded a resultant stress ratio (i.e., calculated / allowable) that was less than or equal to 1.0, the resultant stress remains acceptable. For those conditions where the resultant stress ratio is greater than 1.0, the calculations were revised and/or piping support modifications were performed to bring the stress at EPU conditions within allowable limits.

The thermal "change factor" was based on the ratio of the thermal power uprate to pre-thermal power uprate operating temperature. That is, the thermal change factor is $(T_{uprate}-70°F)/(T_{pre-uprate}-70°F)$. Using this method for the thermal change factor, evaluations resulted in a bounding evaluation of the thermal impact on piping stresses and loads.

Similarly, the pressure "change factor" was determined by the $P_{uprate}/P_{pre-uprate}$ ratio and the flow rate "change factor" was determined by the $Flow_{uprate}/Flow_{pre-uprate}$ ratio. The total design load change factor is the total combined load associated with EPU conditions divided by the allowable design load, and was determined by the following formula:

[Dead Weight (DW) + $\text{Pressure}_{\text{uprate}}$ + $\text{Thermal}_{\text{uprate}}$ + $\text{TransientLoad}_{\text{uprate}}$ + Seismic] / Design $\text{Load}_{\text{analyzed}}$.

Thermal changes were found to be the most significant, primarily for systems using the suppression pool as a water suction source during long term post-LOCA conditions. No changes to the suppression pool loads (i.e., pool swell, condensation oscillation, chugging and SRV discharge) will result from the EPU because previous load definitions were determined to be bounding. Pressure changes were typically found to be negligible and were unchanged for most systems. There is a slight increase in predicted design basis accident (DBA) pressures inside the torus. However, most torus attached piping systems and components were previously analyzed for the maximum intermediate break analysis pressures, which bound even the new DBA pressures. Flow changes were found to be significant only for the MS and feedwater/condensate systems. A detailed evaluation of the MS system was performed for the increased flow rate and is discussed in more detail in the response to Question 13A.

All piping systems subject to changes in temperature, pressure or flow were screened to determine the impact on the piping and piping components (i.e. supports, penetrations, equipment nozzles, etc.). Piping systems subjected to minor operating condition increases due to EPU were excluded from a detailed evaluation, as follows.

Thermal load increases of up to 5% (i.e., change factors between 1.00 and 1.05), were considered acceptable since these increases are offset by conservatism in analytical methods used to calculate the existing stresses and loads. Conservatisms include the enveloping of multiple thermal operating conditions and not considering pipe support gaps in the thermal analyses.

Furthermore, in accordance with industry practice, piping systems that have operating temperatures less than 150°F did not require evaluation for thermal change effects.

Pressure load increases up to 5% were considered acceptable due to margins in piping wall thickness.

Transient load increases up to 5% resulting from EPU related fluid flow rate changes were considered acceptable due to conservatism in load combinations (i.e., transient loads are combined with other conservative loads such as thermal and seismic).

Total design load increases of 5% were considered minor and acceptable by engineering judgment due to inherent conservatism in piping analysis methodology, as previously described.

The total design load criteria was not used for drywell steel, corner room steel, and/or flued head anchors without reviewing their qualification documentation to ensure that similar reasoning to this criteria had not been previously invoked for other load increases.

If the increases described above exceeded 5%, the analyzed margin between design load and the allowable load prior to uprate was used to justify the increases for uprate conditions (e.g., if the load increased by 15%, but the piping component analysis showed a 20% margin to allowable, the component was considered acceptable).

If the load increase on a piping component was greater than the calculated available margin, then a detailed evaluation of the component was performed to evaluate the adequacy of the component for EPU conditions. If the detailed evaluation could not justify the increased EPU loads in accordance with the previously defined acceptance criteria, a modification was designed for that component such that the modified component would meet that acceptance criteria. A description of the modifications required to qualify the piping and piping components for EPU conditions is provided in the response to Question 13B.

All piping systems and piping components with changes in temperature, pressure or flow rate were screened for impact by EPU. If the change factor for the piping system was less than 1.05, the whole system, including the piping components (i.e., supports, penetrations, equipment nozzles, etc.), was considered acceptable. If any of the change ratios exceeded 5%, each piping component was reviewed independently.

The evaluation methodology used to assess impact of the long term post-LOCA temperature increase on torus water piping system components (piping components in systems pumping or exposed to the torus water) is provided in more detail below, by component type:

Pipe Stress
The basic approach for the pipe stress evaluation was to scale up the existing Level A ASME Equation 10 pipe stresses by the thermal change ratio. The revised stress was then compared to the allowable pipe stress associated with the post-LOCA thermal condition. The application of ASME and B31.1 for the EPU pipe stress evaluations is consistent with the existing design and licensing basis.

The allowable pipe stress for post-LOCA conditions was based on the code of record for each piping system for one time secondary loads (e.g., single non-repeated anchor movement). For ASME piping, the allowable stress was taken as 3 S_h (equal to 45,000 psi for A-106 Gr. B piping). For B31.1 piping, the allowable was taken as 1.8 S_h (equal to 27,000 psi for A-106 Gr. B piping). For B31.1 piping, as an alternate, an allowable of 3 S_h minus the actual deadweight (DW) and pressure stresses is allowed by Section 102.3.2d of B31.1.

Rigid Pipe Supports
Rigid supports were categorized as those supports that rigidly support both static and dynamic loads and include rod hangers where applicable, struts, guides, and piping anchors, etc. The basic approach was to calculate a revised post-LOCA load combination of DW plus EPU thermal (T) (i.e., thermal expansion plus thermal anchor movement) plus safe shutdown earthquake (SSE) plus EPU torus displacement (TD). This load combination was classified as a

Level D or faulted load combination. Therefore, a revised interaction coefficient (IC) (i.e., actual stress divided by allowable stress) was calculated by multiplying the maximum IC in the existing calculation by the total design load change factor defined as the new post-LOCA load combination (DW+T+SSE+TD) divided by the largest peak qualified load. In addition, for supports subjected to frictions loads (i.e., guide supports), or supports with integral welded attachments, additional evaluations were performed.

Snubbers

Since snubbers do not resist thermal loads, the new EPU thermal conditions will not affect the snubber loads. The thermal displacement will increase however, so there is a potential for a top out or bottom out condition associated with the increased thermal displacements from EPU. In the late 1980s, allowable cold setting ranges were determined for each snubber to ensure that sufficient travel was available such that the snubbers would not bottom or top out on their range during thermal expansion. Included in this range calculation was a minimum of a ½ inch travel margin provided on each end of the range. Therefore, a minimum of ½ inch of travel is available to handle additional thermal expansion above and beyond the current design displacements. A generic evaluation was performed, which concluded that the increase in thermal displacements due to the EPU would not exceed the ½ inch available travel.

In addition, the increased displacement will cause an increase in the swing angle for snubbers and other pinned supports. A generic evaluation was performed, which concluded that the increase in swing angles due to EPU conditions is minor and will not impair the functionality of the pinned type supports.

Spring Hanger Supports

For each affected spring hanger, the increased vertical thermal displacement was compared to the available displacement to top/bottom-out conditions. If the additional displacement exceeded the available displacement by more than 5%, then a modification was issued to reset or replace the existing spring can. The increase/decrease in the spring hanger load due to movement change is considered to be negligible.

Displacements at Interferences

Some piping models have displacement checks at certain locations where there may be interferences with nearby structures (i.e., slab or wall penetrations, nearby plant equipment, etc.). The locations that were impacted were evaluated to make sure the revised thermal displacements did not result in damaging contact with these interferences.

Flanges

Some of the piping models have in-line flanges that have been evaluated for piping moments. These moments in the piping system are affected by the increase in temperature for these lines. For the affected flanges, revised thermal moments were calculated for the flanged joints and compared to the previously calculated allowables.

Valves

The stresses in valve bodies were already enveloped by the stresses reported for the piping, so these valves were covered in the piping stress evaluation. For valves with extended operators (i.e., motor operated valves (MOVs)), the stresses are a function of the valve acceleration and are not affected by increased thermal loads.

Containment Penetrations

Some of the piping systems penetrate the primary containment boundary (i.e., the torus or the drywell). At these penetrations, the containment shell is evaluated for the local stresses in the vicinity of the penetration due to the reactions at the penetration. The total stress in the containment shell is a combination of the local stresses due to the reaction loads from the piping, combined with the global shell stresses due to conditions inside containment. The revised post-LOCA forces and moments were calculated for all six degrees of freedom and compared to the previously qualified loads. In some cases, revised combined stresses in the containment were calculated and compared to the allowable stresses.

Equipment Nozzles

The existing design basis for piping loads on equipment is that the nozzles and casings are considered acceptable if the attached piping stress at the nozzles meets the code requirements for the piping. For certain equipment, a seismic qualification utility group (SQUG) type evaluation had previously been performed, where the equipment anchorage was evaluated considering the piping reaction loads. This approach was extended to cover non-SQUG equipment such as the core spray (CS) pumps. The affected equipment included the LPCI and CS pumps and the LPCI heat exchangers at DNPS and the RHR and CS pumps and the RHR heat exchangers at QCNPS. If the loads on this equipment increased by more than 5%, the equipment anchorage was re-evaluated. In some cases, it was concluded that certain equipment is bounded by other similar equipment that had been previously evaluated and accepted (i.e., identical equipment with higher nozzle loads).

Reactor Nozzles

Some of the piping systems tie directly into reactor nozzles. At these nozzles, an evaluation was performed to determine the impact of the nozzle reaction loads on the RPV. The revised stresses in the RPV nozzles were calculated for EPU conditions and compared to the previously calculated allowable stresses. The nozzles were also previously evaluated for fatigue considerations. Since the EPU post-LOCA thermal condition is a one-time event, its impact on the fatigue analysis of the nozzle was determined to be negligible.

Results

The results of the piping evaluations are provided in Tables 9A-1, 9A-2, 9A-1QC, 9A-2QC, 9A-3, 9A-4, 9A-3QC, and 9A-4QC. All large bore (i.e., > 4" normal pipe size (NPS)) torus water piping systems were evaluated for the effect of increased operating temperatures and pressures. The resulting pipe stress for each piping system and the corresponding allowable stresses are shown in Tables 9A-1, 9A-2, 9A-1QC, and 9A-2QC. The scope of the small bore torus water piping systems that were evaluated for EPU conditions included small bore piping directly attached to the torus and small bore piping connected to large bore piping that is directly attached to the torus. Also, small bore lines attached to large bore lines that are not torus attached but transmit torus water during the long term post-LOCA mode were evaluated. The current and resulting EPU pipe stress for each small bore piping system and the corresponding allowable stresses are shown in Tables 9A-3, 9A-4, 9A-3QC, and 9A-4QC.

Piping components (i.e., pipe supports, etc.) were evaluated as described above. In some cases modifications were required to ensure the components could handle the increased thermal loads due to the EPU. If modifications were required, the stresses shown in the tables reflect the post-modification calculated stresses. A summary of all the piping component modifications is provided in the response to Question 13B.

B. In some instances different software codes were used in the evaluation of various piping systems and piping components (i.e., pipe supports) when detailed analysis was required to evaluate a system or component. The following software codes were used, along with a description of how they were benchmarked.

Piping Analysis Software

PIPSYS was used for piping analysis for certain torus water piping systems when a more detailed analysis was required. These piping systems were previously analyzed using the proprietary software PISTAR. In these cases PIPSYS was only used to analyze non-Mark I load cases (i.e., deadweight, seismic, and thermal). PIPSYS is a widely used piping analysis software which was procured from Sargent & Lundy (S&L) and has been verified and validated for use on nuclear projects in accordance with the S&L Quality Assurance Program.

NUPIPE-SWPC was used for piping analysis for certain torus water and main steam piping systems when a more detailed analysis was required. NUPIPE-SWPC is suitable for use in nuclear safety related applications and has been benchmarked to industry standards and codes. It is documented, reviewed, approved and controlled in accordance with the Stone & Webster Quality Assurance Program.

Frame Analysis Software

GT-STRUDL and PC-PREPS were used for frame analysis for certain torus water and main steam piping supports when a more detailed analysis was required. Some of these supports were previously analyzed using GENSAP or using manual calculations. GT-STRUDL and PC-PREPS are suitable for use in nuclear safety related applications and have been benchmarked to industry standards and codes. They are documented, reviewed, approved and controlled in accordance with the Stone & Webster Quality Assurance Program.

STAAD-III was used in the frame analysis of certain MS pipe supports inside the drywell. These supports were previously analyzed manually. STAAD-III is a widely used analysis software

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which has been verified and validated for use on nuclear projects in accordance with the S&L Quality Assurance Program.

Baseplate Analysis Software
NPLATE was used for baseplate analysis for certain torus water pipe supports. Some of these supports were previously analyzed using SDAL or BASEPLATE II software or by hand calculations. NPLATE is a widely used baseplate analysis software which was procured from Duke Engineering and was verified and validated for use on nuclear projects as part of the Duke Engineering Quality Assurance Program.

Fluid Transient Forcing Function Development Software
STEHAM was used for fluid transient forcing function development for main steam piping when a more detailed analysis was required. STEHAM is suitable for use in nuclear safety related applications and has been benchmarked to industry standards and codes. It is documented, reviewed, approved and controlled in accordance with the Stone and Webster Quality Assurance Program.

Integral Welded Attachment Analysis Software
ANSYS, PILUG, PITRUST and PITRIFE were used for integral welded attachment analysis for certain torus water and main steam piping supports when a more detailed analysis was required. ANSYS, PILUG, PITRUST and PITRIFE are suitable for use in nuclear safety related applications and have been benchmarked to industry standards and codes. They are documented, reviewed, approved and controlled in accordance with the Stone and Webster Quality Assurance Program.

Question
11. A. Discuss the functionality of safety-related mechanical components (i.e., all safety-related valves and pumps, including air-operated valves (AOV) and safety and relief valves) affected by the proposed power uprate to ensure that the performance specifications and technical specification requirements (e.g., flow rate, close and open times) will be met for the proposed power uprate.

B. Confirm that safety-related air operated valves (AOVs) and motor-operated valves (MOVs) will be capable of performing their intended function(s) following the proposed power uprate including such affected parameters as fluid flow, temperature, pressure and differential pressure, and ambient temperature conditions.

C. Identify the mechanical components that were not evaluated at the uprated power level.

E. Provide an evaluation of the effect of increased temperature due to power uprate on thermally-induced pressurization of piping runs penetrating the containment that were evaluated in response to Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions."

Response

A. Plant mechanical systems, including safety-related mechanical components, were evaluated to assess operating condition changes at EPU. As described in Reference 1, some plant systems were determined to be not impacted or only slightly impacted by EPU. For the remaining plant systems, further evaluations were performed to ensure the adequacy of the system components to operate as required at EPU conditions. This review included all safety-related mechanical components (e.g., pumps and valves) within the system. Safety-related pumps, safety relief valves and other components were determined to be adequately designed for operation at EPU conditions.

Refer to the response to Question 11B for further discussion on AOVs and MOVs.

B. In addition to the mechanical component review discussed in the response to Question 11A, AOVs and MOVs were reviewed in more detail. All MOVs in the Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing And Surveillance," program have been evaluated for EPU process and ambient conditions changes, including parameters such as fluid flow, temperature, pressure, differential pressure and ambient temperature. These evaluations confirmed that the existing analysis for each MOV bounds the EPU conditions.

Safety-related AOVs have been categorized into an AOV Program and evaluated utilizing the Joint Owners' Group (JOG) methodology. All AOVs included in this program have been evaluated for EPU process and ambient conditions changes, including parameters such as temperature, pressure, flow and differential pressure, similar to that previously described for MOVs to confirm the AOVs operate as required after EPU implementation.

C. There is no listing of the mechanical components that were not specifically evaluated or determined not to be impacted by EPU. However, PUSAR Section 6.8, "Systems Not Impacted by EPU," identifies those systems that were generically dispositioned as unaffected by EPU in Reference 1, Section J, "Methods and Assumptions for System Equipment Evaluation."

For systems that are impacted by EPU, the components affected are discussed on a system by system basis throughout the PUSAR.

E.

DNPS

Piping runs penetrating the containment that were evaluated in the response to GL 96-06 were confirmed adequate for uprate conditions by one of the following methods.

- Penetration piping with relief valves. Relief valves set pressures are not affected by uprate conditions. Existing relief capacities are much greater than required, enveloping any slight increase in relief capacity required from heat transfer to the isolated section due to EPU.

- Penetration piping with a bypass. Piping runs containing a bypass line with a spring check valve are not affected by uprate conditions for thermal overpressurization.
- Other water-filled penetration piping. In some cases, EPU conditions slightly increase the heat transfer to the isolated water-filled piping. Adequate conservatism exists in the original design to accommodate the resulting slight increase in internal pressure.

QCNPS

Piping runs penetrating the containment that were evaluated in the response to GL 96-06 were confirmed adequate for uprate conditions by one of the following methods.

- Penetration piping with relief valves. Relief valves set pressures are not affected by uprate conditions. Existing relief capacities are much greater than required, enveloping any slight increase in relief capacity required from heat transfer to the isolated section due to EPU.
- Other water-filled penetration piping. In some cases, EPU conditions slightly increase the heat transfer to the isolated water-filled piping. Adequate conservatism exists in the original design to accommodate the resulting slight increase in internal pressure.

Question

12. A. In reference to Section 3.11, provide a summary addressing your evaluation of the effects of the proposed power uprate on the balance-of-plant (BOP) piping, components, and pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers and anchorages.

B. Provide the calculated maximum stresses and fatigue usage factors for the most critical BOP piping systems, the allowable limits, the code of record and code edition used for the power uprate conditions. If different from the code of record, justify and reconcile the differences.

C. In Appendix G of the submittal, you indicated that some feedwater heater relief valves will be adjusted or replaced and the heaters will be rerated to compensate for the increased feedwater flow and the associated pressure change. You also indicated that condenser tube staking is planned for the main condensers to provide adequate protection against tube vibration damage at uprated power conditions. Provide a summary of your evaluation of the main condenser tubes at the uprated condition.

Response

A. The BOP piping systems include all other affected piping systems not included in the piping systems addressed in the response to Questions 8, 9, and 13. These systems were evaluated using the same methodology and criteria discussed in the response to Question 9A. With the exception of MS, which is described in Question 13A, most of these BOP systems will not experience significant changes in operating conditions due to EPU. A description of the piping systems examined, and the results of these evaluations are provided in Table 12A-1.

B. The calculated maximum stresses and fatigue usage, the allowable limits, the code of record and code edition used for the EPU conditions factors for the most critical piping systems are provided in the response to Questions 8, 9, and 13. The remaining BOP affected systems passed the screening criteria discussed in the response to Question 9A, and no new analyses were required.

C.
DNPS
The main condenser tubes were evaluated at EPU conditions to determine which areas of the condenser tube bundle would be subject to potentially damaging tube vibration and to determine the extent and length of the stakes required to prevent such damage. Heat transfer relations were used to determine the overall performance of the condenser at the uprated condition. Steam flow velocities within the condenser were then determined based on the calculated heat transfer performance of the condenser. These velocities were used to evaluate the vibration criteria established from H. J. Conners, "Fluid-Elastic Vibration of Heat Exchanger Tube Arrays."

The plots of the Conners vibration parameters analyzed at winter conditions (i.e., worst case) indicate areas susceptible to fluid-elastic vibration. From this, the location and length of required stakes were determined.

QCNPS
The main condenser tubes were evaluated at the uprated conditions to determine which areas of the condenser tube bundle would be subject to potentially damaging tube vibration and to determine the extent and length of the stakes required to prevent such damage. Heat transfer relations were used to determine the overall performance of the condenser at the uprated condition. Steam flow velocities within the condenser were then determined based on the calculated heat transfer performance of the condenser. These velocities were used to evaluate the vibration criteria established from H. J. Conners, "Fluid-Elastic Vibration of Heat Exchanger Tube Arrays."

The plots of the Conners vibration parameters analyzed at winter conditions (i.e., worst case) indicate areas susceptible to fluid-elastic vibration. From this, the location and length of required stakes were determined. The currently installed staking was then compared to the stake locations and lengths determined in the analysis and was found to be adequate. No additional staking will be installed.

Question
13. A. In reference to Sections 3.5 and 4.1.2, provide a discussion of the evaluation of piping systems attached to the torus shell, vent penetrations, pumps, and valves, that are affected by increased torus temperature and changes in LOCA dynamic loads (pool swell, condensation oscillation, and chugging) and increased temperature and flow in the main steam and feedwater systems due to the proposed power uprate.

B. Identify supports and piping systems that require modifications as a result of the proposed extended power uprate.

Response

A. For piping systems other than MS, refer to the responses to Questions 8, 9, and 12.

The EPU does not affect design basis loads for the MS system. However, the MS system flow will increase by approximately 20% for EPU. A review of the increase in flow related loads associated with EPU indicates that piping loads due to the dynamic effects of the TSV fast closure, which is not included in the design basis loads, results in significant loads for the MS piping and supports.

DNPS and QCNPS are pre-General Design Criteria Plant (GDC) plants and were designed to USAS B31.1 – 1967, which required consideration of the most severe condition of coincident pressure, temperature, and loading. B31.1 – 1967 required that the plant transient dynamic load for safety valve opening be included in the design requirements. The Standard Review Plan (SRP), Section 10.3, "Main Steam Supply System," Revision 3, stated that main steam systems must be designed to withstand the effects of rapid valve closure. However Subsection V, "Implementation," of SRP Section 10.3 states that currently licensed plants (i.e., prior to 1984) do not need to adhere to this requirement. Thus, neither the GDC nor SRP requirements regarding consideration of transient dynamic loads due to TSV closure have been applied to DNPS or QCNPS.

Even though consideration of TSV loads was determined to be beyond the design basis, it is prudent to address these loads. The EPU evaluation approach for the TSV loads is based on an acceptance criteria for the TSV loads which are less restrictive than the current application of the ASME and American Institute for Steel Construction (AISC) codes, but which ensure that no permanent deformation of the piping, piping supports or supporting structural steel will occur as a result of the event.

Under EPU conditions the TSV closure loads were analyzed and modifications were implemented to ensure that the TSV closure does not result in MS piping failure. Since there is no current licensing basis for the acceptance criteria for the TSV loads, load combinations and acceptance criteria for the TSV loads were developed for the EPU evaluations. The MS piping, pipe supports, and supporting structures were evaluated for the TSV fluid transient loads in combination with pressure, deadweight, thermal, safety relief valve (SRV), and pipe break loads, as appropriate. Since a seismic event may cause a unit trip and a TSV closure, the TSV transient loads were also considered concurrent with applicable seismic loads. Since the TSV closure event is considered beyond the current licensing basis, a TSV event was considered to occur concurrently with the SSE only. The evaluation method is to demonstrate pressure boundary integrity of the piping and associated member/component evaluated to ensure that no gross deformation or integrity failure occurs. Also, due to the time relationships between the significant loads resulting from TSV, SRV discharge, and pipe break events (i.e., LOCA), no combination of these loads is required.

To demonstrate piping pressure boundary integrity subsequent to a TSV closure event, the piping, pipe supports and supporting structures were evaluated for the following additional loading combinations (LC).

Piping:

LC 1 Dead Load + Pressure + TSV Loads
LC 2 Dead Load + Pressure + $[(\text{TSV Loads})^2 + (\text{SSE Loads})^2]^{1/2}$

Pipe Supports and Pipe Support Structures:

LC 3 Dead Load + Operating Thermal Loads + TSV Loads
LC 4 Dead Load + Operating Thermal Loads + $[(\text{TSV Loads})^2 + (\text{SSE Loads})^2]^{1/2}$

The TSV fluid transient loads were generated utilizing the representative and bounding effective closing time for the TSV. For dynamic load combinations, oscillator (i.e., piping system) damping were considered to be 2% when considering TSV alone (i.e., LC 1) and 3% when combined with seismic (i.e., LC 2), in accordance with guidance contained in Reg. Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants." Seismic damping values are based on the values stipulated in the Updated Final Safety Analysis Report (UFSAR).

For evaluation of the supporting drywell steel, where supports from different main steam lines are attached to the same drywell steel, the TSV loads were combined by the square root of the sum of the squares (SRSS) method. This is due to the variation in actuation time, which results in the pressure wave for different MS lines being out-of-phase with the peak loads occurring at different times.

Design Criteria for Structural Steel and Pipe Support Evaluations

LC 3 – Dead load + Operating Thermal Loads + TSV Loads
Acceptance criteria: The allowable stresses shall be limited to 1.33 x Normal AISC Allowable stresses.

The following table summarizes the acceptance criteria for the load combinations listed above.

APPLICABLE TSV LOAD COMBINATIONS	**ACCEPTANCE CRITERIA**
STRUCTURAL & AUXILIARY STEEL	
DW + TH* + TR**	NORMAL 1.33 x AISC Allowable
DW + TH + $(SSE^2 + TR^2)^{1/2}$	FAULTED 1.60 x AISC Allowable < 0.95 x Fy***
EXPANSION ANCHOR BOLTS	
DW + TH + TR	SAFETY FACTOR = 4
DW + TH + $(SSE^2 + TR^2)^{1/2}$	SAFETY FACTOR = 2
PIPE SUPPORT COMPONENTS	
DW + TH + TR	ASME LEVEL C
DW + TH + $(SSE^2 + TR^2)^{1/2}$	ASME LEVEL D
PIPING	
DW + P + TR	ASME Level C
DW + P + $(SSE^2 + TR^2)^{1/2}$	ASME Level D

*TH = thermal loads
*TR = transient Loads such as TSV
*** Plastic section modulus can be used to determine the section stresses but must meet ductility criteria.

LC 4 – Dead Load + Operating Thermal Loads + SSE Loads + TSV Loads

Structural Steel Members Acceptance Criteria

Stress	Design Limit
Bending	1.6 x AISC allowable based on plastic section modulus with stresses not to exceed 0.95 x Fy. For this to be used, the section should satisfy the compact section criteria and lateral bracing requirements of the AISC Code. AISC LRFD Specification may be consulted to obtain further clarifications.
Axial	1.6 x AISC allowable not < 0.95 x Fy
Shear	0.95 x Fy / $(3)^{1/2}$ = 0.548 x Fy

Plate Materials Acceptance Criteria

Stress	Design Limit
Bending about Weak Axis	0.95 x Fy based on plastic section modulus
Bending about Strong Axis	0.95 x Fy based on plastic section modulus or 1.0 x Fcr based on elastic section modulus, whichever is smaller.
Shear	0.95 x Fy / $(3)^{1/2}$ = 0.548 x Fy

Bolts Acceptance Criteria
1.60 x AISC Allowables.

Welds Acceptance Criteria
1.60 x AISC Allowables. The base metal shear for welds other than fillets shall not exceed 0.548 x Fy of the base metal. Base metal stress shall not govern for fillet welds.

Where the MS pipe supports combined loads as defined in combinations LC3 and LC4 do not exceed the original design basis loads (i.e., LC3 compared to operating basis earthquake (OBE) loads, and LC4 compared to SSE loads), the supporting structure was not reevaluated for the beyond design basis combinations.

The maximum stress ratios for each of the MS piping subsystems impacted by the TSV loads are provided in Table 13-1. The resultant pipe supports and drywell steel modifications are summarized in the response to Question 13B. With the modifications, the MS piping, pipe supports, and supporting drywell steel meet the above acceptance criteria. In addition, the current design and license basis criteria are met for the EPU conditions.

B. Table 13-2 identifies supports and piping systems that require modifications as a result of the extended power uprate.

Question
14. In Appendix G of the submittal, you indicated that restriction orifices to the stator water cooling system will be resized to accommodate the increased heat load. Additional cooling towers will be installed to ensure that the temperature of the water released to the environment remains within existing limits.

Confirm whether the proposed power uprate will increase the accident temperature, pressure and sub-compartment pressurization that affect the design basis analyses for steel and concrete in the containment, steam tunnel and the spent fuel pool. If the structural steel and concrete will

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be affected, provide the design basis margin and margins after considering increased accident loading due to the proposed power uprate.

Response
The EPU accident temperatures and pressures are bounded by the original structural design temperatures and pressures of the containment and containment sub-compartments, including the pressure suppression system and torus. Refer to PUSAR Sections 4.1.1, "Containment Pressure and Temperature Response," and 4.1.2, "Containment Dynamic Loads."

Temperatures and pressures due to feedwater and RWCU HELBs at EPU conditions increased slightly in some sub-compartments outside the containment, including the main steam tunnel (refer to PUSAR Table 10-1). The subcompartment structures were evaluated and are adequate as designed for the slightly increased pressures and temperatures.

Maximum Structural Margin Changes

Structure	**Interaction Ratio (IC)***	
	Pre-EPU	**EPU**
Concrete Sub-Compartments	0.946	0.995
Corner Room Structural Steel	0.62	0.83

* Maximum Allowable Interaction Ratio is 1.0.

The maximum EPU temperatures and pressures for the fuel pool structure and fuel racks are unchanged from the pre-EPU conditions (refer to PUSAR Table 6-2).

Table 9A-1 Large Bore Torus Water Piping Stress Results Dresden Unit 2

Piping Model	Description	Code	Pre-EPU Stress (psi)	(1)EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
D2.02	ECCS Ring Header	EQ. 10a, ASME Class II	37132	42126	45000	0.94
D2.03/D2.04	LPCI/CS Suction	102.3.2d, ANSI B31.1	33906	37007	37888	0.98
D2.08	LPCI Discharge	EQ. 10a, ASME Class II	33844	14700	45000	0.33
D2.05	HPCI Suction	EQ. 10a, ASME Class II	32241	32241	45000	0.72
D2.09.1	LPCI/CS Discharge	EQ. 10a, ASME Class II	25502	44159	45000	0.98
D2.09.2	CS Discharge	102.3.2c, ANSI B31.1	5384	7458	27000	0.28
D2.10	Vacuum Relief	EQ. 10a, ASME Class II	8049	9131	45000	0.20
D2.11	Pressure Suppression	EQ. 10a, ASME Class II	28247	28247	45000	0.63
D2.12	HPCI Turbine Exhaust	EQ. 10a, ASME Class II	13666	18931	45000	0.42
D2.13.1 (Internal)	LPCI Discharge	EQ. 10a, ASME Class II	29619	35435	45000	0.79
D2.13.1 (External)	LPCI Discharge	EQ. 10a, ASME Class II	25205	34916	45000	0.78
D2.13.2/D2.14.2	LPCI Discharge	EQ. 10a, ASME Class II	26010	42786	45000	0.95
D2.14.1 (Internal)	LPCI Discharge	EQ. 10a, ASME Class II	24283	29051	45000	0.65
D2.14.1 (External)	LPCI Discharge	EQ. 10a, ASME Class II	28969	40130	45000	0.89
D2-LPCI-09C	LPCI Discharge	102.3.2c, ANSI B31.1	23802	11601	27000	0.43
D2-LPCI-10C	LPCI Discharge	102.3.2c, ANSI B31.1	23871	11635	27000	0.43
D2-LPCI-12C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D2-LPCI-13C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D2-COSP-02B(C)	CS Discharge, Inside Drywell	102.3.2c, ANSI B31.1	7305	10119	27000	0.37
D2COSP-04C	CS Discharge	102.3.2d, ANSI B31.1	39173	32090	37500	0.86
D2-COSP-01B(C)	CS Discharge, Inside Drywell	102.3.2c, ANSI B31.1	15026	20815	27000	0.77

(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) Thermal stress is considered negligible for the torus spray header since the spray Header and the torus expand uniformly.

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 9A-2 Large Bore Torus Water Piping Stress Results Dresden Unit 3

Piping Model	Description	Code	Pre-EPU Stress (psi)	(1)EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
D3.02	ECCS Ring Header	EQ. 10a ASME CL II	30074	35979	45000	0.80
D3.03/D3.06	LPCI / CS Suction	EQ. 10a ASME CL II	30158	41600	45000	0.92
D3.04/D3.07	LPCI / CS Suction	EQ. 10a ASME CL II	27654	44308	45000	0.98
D3.08.1/08.3	LPCI Discharge	EQ. 10a ASME CL II	29299	34284	45000	0.76
D3.08.2	LPCI Discharge	EQ. 10a ASME CL II	7324	10146	45000	0.23
D3.05	HPCI Suction	EQ. 10a ASME CL II	10503	10503	45000	0.23
D3.09.1	LPCI/CS Discharge	EQ. 10a ASME CL II	18605	32216	45000	0.72
D3.09.2	CS Discharge	EQ. 10a ASME CL II	12080	16734	45000	0.37
D3.09.3	CS Discharge	EQ. 10a ASME CL II	8706	12060	45000	0.27
D3.10	Vacuum Relief	EQ. 10a ASME CL II	18021	24964	45000	0.55
D3.11	Pressure Suppression	EQ. 10a ASME CL II	25427	14001	45000	0.31
D3.12 (Internal)	HPCI Turbine Exhaust	EQ. 10a ASME CL II	19916	27589	45000	0.61
D3.12 (External)	HPCI Turbine Exhaust	EQ. 10a ASME CL II	19916	27589	45000	0.61
D3.13.1 (Internal)	LPCI Discharge	EQ. 10a ASME CL II	26648	31881	45000	0.71
D3.13.1 (External)	LPCI Discharge	EQ. 10a ASME CL II	24088	33368	45000	0.74
D3.13.3	LPCI Discharge	EQ. 10a ASME CL II	14055	18493	45000	0.41
D3.13.2/D3.14.2	LPCI Discharge	EQ. 10a ASME CL II	14079	23160	45000	0.51
D.3.14.1 (Internal)	LPCI Discharge	EQ. 10a ASME CL II	31549	37744	45000	0.84
D.3.14.1 (External)	LPCI Discharge	EQ. 10a ASME CL II	31359	43440	45000	0.96
D3.14.3	LPCI Discharge	EQ. 10a ASME CL II	20662	25828	45000	0.57
D3-LPCI-11C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D3-LPCI-12C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D3-COSP-RP01	CS Discharge, Inside Drywell	EQ. 12 ASME CL I	N/A	26156	60000	0.44
D3-COSP-RP02	CS Discharge, Inside Drywell	EQ. 12 ASME CL I	N/A	5020	52620	0.10
D3-RRCI-RP01	Recirc	EQ. 10a ASME CL II	27772	13053	45000	0.29
D3-RRCI-RP02	Recirc	EQ. 10a ASME CL II	15026	7062	45000	0.16

(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) Thermal stress is considered negligible for the torus spray header since the spray header and the torus expand uniformly.

Table 9A-1QC Large Bore Torus Water Piping Stress Results Quad Cities Unit 1

Piping Model	Description	Code	Pre-EPU Stress (psi)	[1]EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
Q1.02	ECCS Ringheader	Eq 10a, ASME Class II	15301	16780	45000	0.37
Q1.03	RCIC Suction	Eq 10a, ASME Class II	22721	24917	45000	0.55
Q1.04	HPCI Suction	Eq 10a, ASME Class II	11953	16558	45000	0.37
Q1.05	RHR A/B Suction	Eq 10a, ASME Class II	50190	44660	52500	0.85
Q1.06	RHR C/D Suction	Eq 10a, ASME Class II	32627	35781	45000	0.80
Q1.07	Core Spray Suction	Eq 10a, ASME Class II	27998	30704	45000	0.68
Q1.08	Vacuum Relief	Eq 10a, ASME Class II	36037	43509	45000	0.97
Q1.09.1	RHR A/B Discharge	Eq 10a, ASME Class II	37168	40761	45000	0.91
Q1.09.2	RHR A/B Discharge	Eq 10a, ASME Class II	15316	18324	45000	0.41
Q1.09.3	RHR A/B Discharge	Eq 10a, ASME Class II	15316	18324	45000	0.41
Q1.10.1	CS Discharge	Eq 10a, ASME Class II	13727	15054	45000	0.33
Q1.10.2	CS Discharge	Eq 10a, ASME Class II	34021	37310	45000	0.83
Q1.11.1	RHR C/D Discharge	Eq 10a, ASME Class II	29089	31901	45000	0.71
Q1.11.2	RHR C/D Discharge	Eq 10a, ASME Class II	29300	35375	45000	0.79
Q1.11.3	RHR C/D Discharge	Eq 10a, ASME Class II	19350	20372	45000	0.45
Q1.13	HPCI Turbine Exhst	Eq 10a, ASME Class II	20253	22211	45000	0.49
Q1.14	RCIC Turbine Exhst	Eq 10a, ASME Class II	16244	22502	45000	0.50
Q1.15	Pressure Suppression	Eq 10a, ASME Class II	18288	10070	45000	0.22
Q1-RHRS-14B(C)	RHR Fuel Pool Cooling	102.3.2d, ANSI B31.1	21923	26228	27000	0.97
Q1-RHRS-09C	RHR Spray Header	102.3.2d, ANSI B31.1	16381	15796	27000	0.59
EMD-066699	RHR to Recirc	See Note 2				
Q1-COSP-01C	CS Disch Inside drywell	See Note 2				
Q1-COSP-02C	CS Disch Inside drywell	See Note 2				

(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) EPU condition does not control since analyzed at a temperature greater than 201.6 °F.

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 9A-2QC Large Bore Torus Water Piping Stress Results Quad Cities Unit 2

Piping Model	Description	Code	Pre-EPU Stress (psi)	[1]EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
Q2.02	ECCS Ringheader	Eq 10a, ASME Class II	29687	32557	45000	0.72
Q2.03	RCIC Suction	Eq 10a, ASME Class II	8234	9030	45000	0.20
Q2.04	HPCI Suction	Eq 10a, ASME Class II	26154	28682	45000	0.64
Q2.05	RHR A/B Suction	Eq 10a, ASME Class II	18020	19762	45000	0.44
Q2.06	RHR C/D Suction	Eq 10a, ASME Class II	22705	24975	45000	0.56
Q2.07	Core Spray Suction	Eq 10a, ASME Class II	27808	38521	45000	0.86
Q2.08	Vacuum Relief	Eq 10a, ASME Class II	25128	30338	45000	0.67
Q2.09.1	RHR A/B Discharge	Eq 10a, ASME Class II	23098	37996	45000	0.84
Q2.09.2	RHR A/B Discharge	Eq 10a, ASME Class II	22752	27220	45000	0.60
Q2.09.3	RHR A/B Discharge	Eq 10a, ASME Class II	22752	27220	45000	0.60
Q2.10.1	CS Discharge	Eq 10a, ASME Class II	18442	20225	45000	0.45
Q2.10.2	CS Discharge	Eq 10a, ASME Class II	5975	6553	45000	0.15
Q2.10.3	CS Discharge	Eq 10a, ASME Class II	8300	9102	45000	0.20
Q2.11.1	RHR C/D Discharge	Eq 10a, ASME Class II	35941	39415	45000	0.88
Q2.11.2	RHR C/D Discharge	Eq 10a, ASME Class II	29749	35591	45000	0.79
Q2.11.3	RHR C/D Discharge	Eq 10a, ASME Class II	23230	24457	45000	0.54
Q2.13	HPCI Turbine Exhst	Eq 10a, ASME Class II	16819	23299	45000	0.52
Q2.14	RCIC Turbine Exhst	Eq 10a, ASME Class II	7500	10500	45000	0.23
Q2.15	Pressure Supp.	Eq 10a, ASME Class II	18168	10004	45000	0.22
Q2-RHRS-09B(C)	RHR Fuel Pool Cooling	102.3.2d, ANSI B31.1	13997	14855	27000	0.55
Q2-RHRS-09C	RHR Spray Header	See Note 2				
EMD-066794	RHR to Recirc	See Note 2				
EMD-067695	CS Disch inside drywell	102.3.2d, ANSI B31.1	19600	19600	26400	0.74

(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) EPU condition does not control since analyzed at a temperature greater than 201.6 °F.

Table 9A-3 Small Bore Torus Water Piping Stress Results Dresden Unit 2

Calculation Number	System Identification***	Pre-EPU Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio (EPU/Allowable)
27.0200.2053.007	PS	20524	28431	45000	0.63
27.0200.2053.009	PS	24658	34158	45000	0.76
27.0200.2053.010	DAP	27712	38388	45000	0.85
27.0200.2053.013	PS	31280	43331	45000	0.96
27.0200.2053.014	PS	24243	33583	45000	0.75
27.0200.2053.015	PS	24243	33583	45000	0.75
27.0200.2053.016	PS	35205	19385	45000	0.43
27.0200.2053.028	N	35284	35284	45000	0.78
27.0200.2053.030	Core Spray	3514	4868	45000	0.11
27.0200.2053.040	Core Spray	16638	27370	45000	0.61
27.0200.2053.041	Core Spray	16527	27187	45000	0.60
27.0200.2053.043	LPCI	22329	30932	45000	0.69
27.0200.2053.051	LPCI	25552	35396	45000	0.79
27.0200.2053.059	LPCI	23592	38809	45000	0.86
27.0200.2053.061	LPCI	1651	5743	45000	0.13
27.0200.2053.062	LPCI	21879	35113	45000	0.78
27.0200.2053.063	LPCI	30095	30614	45000	0.68
27.0200.2053.074	LPCI	17934	36398	45000	0.81
27.0200.2053.077	LPCI	20924	33580	45000	0.75
27.0200.2053.078	LPCI	26073	41844	45000	0.93
27.0200.2053.079	LPCI	36901	34547	45000	0.77
27.0200.2053.089	HPCI	23780	41177	45000	0.92
27.0200.2053.090	HPCI	15108	24853	45000	0.55
27.0200.2053.102	CAM	38584	53449	56400	0.95
27.0200.2053.103	CAM	40117	55573	56400	0.99
27.0200.2053.104	ACAD	33094	43185	45000	0.96
27.0200.2053.105	ACAD	33118	44904	45000	1.00
D2-LPCI-02B(C)/Analysis	LPCI	34910	41853	45000	0.93

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
LPCI = Low Pressure Coolant Injection
HPCI = High Pressure Coolant Injection
CAM = Containment Atmosphere Monitoring
ACAD = Atmosphere Containment Atmosphere Dilution
N = Nitrogen Inerting and Drywell Oxygen Sampling

Table 9A-4 Small Bore Torus Water Piping Stress Results Dresden Unit 3

Calculation Number	System Identification***	Pre-EPU Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio (EPU/Allowable)
27.0200.2058.007	PS	30656	42467	45000	0.94
27.0200.2058.008	PS	27414	37976	45000	0.84
27.0200.2058.009	DAP	34792	48196	56400	0.85
27.0200.2058.013	PS	29963	36795	45000	0.82
27.0200.2058.014	PS	15562	20354	45000	0.45
27.0200.2058.015	PS	11961	12220	45000	0.27
27.0200.2058.016	PS	33689	18550	45000	0.41
27.0200.2058.049	Core Spray	29989	44889	45000	1.00
27.0200.2058.050	Core Spray	20314	35175	45000	0.78
27.0200.2058.051	LPCI	2047	2836	45000	0.06
27.0200.2058.052	LPCI	14702	20366	45000	0.45
27.0200.2058.061	LPCI	6963	9646	45000	0.21
27.0200.2058.062	LPCI	26056	36094	45000	0.80
27.0200.2058.075	LPCI	22376	38746	45000	0.86
27.0200.2058.089	LPCI	20364	35262	45000	0.78
27.0200.2058.095	LPCI	26166	41993	45000	0.93
27.0200.2058.113	HPCI	25906	37122	45000	0.82
27.0200.2058.114	HPCI	15108	24853	45000	0.55
27.0200.2058.120	CAM	28674	37884	56400	0.67
27.0200.2058.121	CAM	24308	32009	56400	0.57
27.0200.2058.122	ACAD	24684	32738	45000	0.73
27.0200.2058.123	ACAD	32547	43121	45000	0.96
D3-LPCI-02B(C)/Analysis	LPCI	11813	14766	45000	0.33

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
LPCI = Low Pressure Coolant Injection
HPCI = High Pressure Coolant Injection
CAM = Containment Atmosphere Monitoring
ACAD = Atmosphere Containment Atmosphere Dilution

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 9A-3QC Small Bore Torus Water Piping Stress Results Quad Cities Unit 1

Calculation Number	System Identification***	Pre-EPU Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio (EPU/Allowable)
27.0200.1053.001	PS	15000	24675	45000	0.55
27.0200.1053.002	PS	19000	31255	45000	0.69
27.0200.1053.006	PS	26680	36959	45000	0.82
27.0200.1053.007	PS	14341	19866	45000	0.44
27.0200.1053.008	PS	25019	13776	45000	0.31
27.0200.1053.010	DAP	30454	42187	56400	0.75
27.0200.1053.011	PS	12658	17535	45000	0.39
27.0200.1053.012	PS	7524	10423	45000	0.23
27.0200.1053.019	Core Spray	24390	33787	45000	0.75
27.0200.1053.020	Core Spray	21771	30159	45000	0.67
QDC-1000-S-0456	RH	28749	31528	45000	0.70
27.0200.1053.043	RH	32295	42722	45000	0.95
27.0200.1053.047	RH	17654	24455	45000	0.54
27.0200.1053.059	HPCI	18205	25219	45000	0.56
Q1-HPCI-04B(C)	HPCI	13915	13915	45000	0.31
27.0200.1053.069	HPCI	15000	24675	45000	0.55
27.0200.1053.074	RCIC	7702	10669	45000	0.24
27.0200.1053.077	RCIC	41052	43639	45000	0.97
27.0200.1053.088	HPCI	15356	25261	45000	0.56
27,0200.1053.089	RCIC	16681	27440	45000	0.61
27.0200.1053.117	HPCI	28787	34756	45000	0.77

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
RH = Residual Heat Removal
HPCI = High Pressure Coolant Injection
RCIC = Reactor Core Isolation Cooling

Table 9A-4QC Small Bore Torus Water Piping Stress Results Quad Cities Unit 2

Calculation Number	System Identification***	Pre-EPU Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio (EPU/Allowable)
27.0200.1058.001	Instrument Air	25501	35326	56400	0.63
27.0200.1058.004	PS	26400	36571	45000	0.81
27.0200.1058.005	PS	28612	39635	45000	0.88
27.0200.1058.010	PS	27903	38653	45000	0.86
27.0200.1058.011	PS	11118	15401	45000	0.34
27.0200.1058.012	PS	25116	34792	45000	0.77
27.0200.1058.013	DAP	15686	21729	49800	0.44
27.0200.1058.017	PS/NO	4798	5793	45000	0.13
27.0200.1058.018	PS	30072	36057	45000	0.80
27.0200.1058.032	RH	29342	32178	45000	0.72
27.0200.1058.051	RH	21361	29591	45000	0.66
Q2-RHRS-08B(C)	RH	29147	18179	45000	0.40
27.0200.1058.059	HPCI	29547	40930	45000	0.91
Q2-HPCI-02B(C)	HPCI	12372	12372	45000	0.27
27.0200.1058.066	HPCI	31514	43655	45000	0.97
27.0200.1058.079	HPCI	26405	36578	45000	0.81
27.0200.1058.080	HPCI	31675	43878	45000	0.98
27.0200.1058.081	HPCI	32352	44816	45000	1.00
27.0200.1058.085	RCIC	5077	7033	45000	0.16
27.0200.1058.095	RCIC	25965	37967	45000	0.84
27.0200.1058.096	CAM	44552	34060	56400	0.60
27.0200.1058.097	CAM	19787	27410	56400	0.49
27.0200.1058.102	HPCI	27228	37718	45000	0.84
27.0200.1058.103	Core Spray	13011	14269	45000	0.32
27.0200.1058.104	Core Spray	17922	19654	45000	0.44
QDC-1400-M-033	Core Spray	6640	3121	27000	0.12
Q2-RHRS-06B(C)	RH	36459	36459	45000	0.81
QDC-1000-M-185	RH	21800	21800	27000	0.81

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
RH = Residual Heat Removal
HPCI = High Pressure Coolant Injection
RCIC = Reactor Core Isolation Cooling
CAM = Containment Atmosphere Monitoring
NO = Drywell Nitrogen and Oxygen Analyzer

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 12A-1
Balance of Plant Piping System Evaluation Method and Results
DNPS Units 2 & 3

Piping System	Evaluation Method	Evaluation Results
Main Steam (outside RCPB)	See the response to Question 13A	See the response to Question 13A
Feedwater (outside RCPB)	Increases < 5%	Pass*
Reactor Recirculation	Increases < 5%	Pass
Control Rod Drive	Increases < 5%	Pass
RPV Bottom Head Drain	Increases < 5%	Pass
RPV Head Vent	Increases < 5%	Pass
Isolation Condenser	Increases < 5%	Pass
Shutdown Cooling	Increases < 5%	Pass
SRV Discharge	Increases < 5%	Pass
Reactor Water Clean Up	Increases < 5%	Pass
CCSW	Increases < 5%	Pass
Fuel Pool Cooling	Increases < 5%	Pass
Main Steam Drain Lines	Increases < 5%	Pass
Neutron Monitoring	Increases < 5%	Pass
MS Turbine By-Pass	Increases < 5%	Pass
Standby Liquid Control	Increases < 5%	Pass
Off Gas	Increases < 5%	Pass
Standby Gas	Increases < 5%	Pass
High Radiation Sampling	Increases < 5%	Pass
MS Cross Around Piping	Increases < 5%	Pass
Turbine Cross Around Piping	Increases < 5%	Pass
Condensate & Heater Drain	Increases < 5%	Pass

* FW flow increase factor 1.20, however system contains no fast acting valves and increase in flow is acceptable

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 12A-1
Balance of Plant Piping System Evaluation Method and Results
QCNPS Units 1 & 2

Piping System	Evaluation Method	Evaluation Results
Main Steam (outside RCPB)	See the response to Question 13A	See the response to Question 13A
Feedwater (outside RCPB)	Increases < 5%	Pass*
Reactor Recirculation	Increases < 5%	Pass
Control Rod Drive	Increases < 5%	Pass
RPV Bottom Head Drain	Increases < 5%	Pass
RPV Head Vent	Increases < 5%	Pass
RCIC	Increases < 5%	Pass
SRV Discharge	Increases < 5%	Pass
Reactor Water Clean Up	Increases < 5%	Pass
CCSW	Increases < 5%	Pass
Fuel Pool Cooling	Increases < 5%	Pass
Main Steam Drain Lines	Increases < 5%	Pass
Neutron Monitoring	Increases < 5%	Pass
MS Turbine By-Pass	Increases < 5%	Pass
Standby Liquid Control	Increases < 5%	Pass
Off Gas	Increases < 5%	Pass
Standby Gas	Increases < 5%	Pass
High Radiation Sampling	Increases < 5%	Pass
MS Cross Around Piping	Increases < 5%	Pass
Turbine Cross Around Piping	Increases < 5%	Pass
Condensate & Heater Drain	Increases < 5%	Pass

* FW flow increase factor 1.20, however system contains no fast acting valves and increase in flow is acceptable

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

TABLE 13-1 DNPS

Unit	Subsystem	Code	Calculated Stress (psi)	Allowable Stress (psi)
DNPS Unit 2	MS Line A - RPV to drywell Pen	ASME Level C	24,991	27,000
		ASME Level D	26,766	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	22,532	27,000
		ASME Level D	33,247	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	14,256	27,000
		ASME Level D	25,368	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	22,633	27,000
		ASME Level D	33,504	36,000
DNPS Unit 3	MS Line A - RPV to drywell Pen	ASME Level C	23,487	27,000
		ASME Level D	35,260	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	21,856	27,000
		ASME Level D	34,102	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	17,864	27,000
		ASME Level D	29,610	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	23,607	27,000
		ASME Level D	33,385	36,000
DNPS Unit 2	MS Lines A, B, C & D Outside Drywell	ASME Level C	14,972	27,000
		ASME Level D	13,989	36,000
DNPS Unit 3	MS Lines A, B, C & D Outside Drywell	ASME Level C	14,972	27,000
		ASME Level D	13,989	36,000

ASME Level C = DW + PR +TSV
ASME Level D = DW + PR + SRSS(SSE + TSV)

DW = deadload stress (psi)
PR = pressure stress (psi)
TSV = turbine stop valve stress (psi)
SSE = safe shutdown earthquake stress (psi)

TABLE 13-1 QCNPS

Unit	Subsystem	Code	Calculated Stress (psi)	Allowable Stress (psi)
Quad Cities Unit 1	MS Line A - RPV to drywell Pen	ASME Level C	24,119	27,000
		ASME Level D	33,922	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	20,139	27,000
		ASME Level D	33,733	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	26,025	27,000
		ASME Level D	35,770	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	21,000	27,000
		ASME Level D	35,306	36,000
Quad Cities Unit 2	MS Line A - RPV to drywell Pen	ASME Level C	25,291	27,000
		ASME Level D	35,336	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	26,638	27,000
		ASME Level D	34,459	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	22,441	27,000
		ASME Level D	34,546	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	16,484	27,000
		ASME Level D	29,127	36,000
QCNPS Unit 1	MS Lines A, B, C & D Outside Drywell	ASME Level C	21,673	27,000
		ASME Level D	27,260	36,000
QCNPS Unit 2	MS Lines A, B, C & D Outside Drywell	ASME Level C	21,673	27,000
		ASME Level D	27,260	36,000

ASME Level C = DW + PR +TSV
ASME Level D = DW + PR + SRSS(SSE + TSV)

DW = deadload stress (psi)
PR = pressure stress (psi)
TSV = turbine stop valve stress (psi)
SSE = safe shutdown earthquake stress (psi)

Table 13-2 DNPS

SUPPORT NUMBER	**MODIFICATION DESCRIPTION**
DNPS Unit 2 - TAP SUPPORT MODIFICATIONS	
SUPPORT NUMBER	MODIFICATION DESCRIPTION
2-15-M321315	Change spring hanger loads
2-15-M321423	Revise baseplate mounting
2-15-M3381	Revise U-Bolt
2-14-M320924	Revise baseplate design and add new brace
2-14-M320808	Replace rigid strut with snubber
DNPS Unit 2 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
2-3001A-49	Replace snubber assembly and add stiffener angle and welds
2-02-2870SH1 2-02-2870SH2	Add two box frame supports at MS bypass loop in Turbine Building
2-02-2870SH3 2-02-2870SH4	Add lateral guides inside 2 G-line wall sleeves
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates
2-3001-H86 2-3001-H89	Remove existing pipe supports
DNPS Unit 3 - TAP SUPPORT MODIFICATIONS	
3-14-M340919	Increase the size of existing welds on support cleats
3-14-M340921	Install additional stiffener plates and associated welds
3-15-M340819	Add additional welds to existing support
3-15-M340827	Install additional stiffener plates and add additional welds to existing support
3-15-M340906	Add new brace with associated baseplate and anchor bolts
DNPS Unit 3 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
3-3001A-S2	Add new welds and stiffener plates to existing members
3-3001C-S2	Add new support member and welds and reduce length of snubber extension piece
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates
3-02-3870SH1 3-02-3870SH2	Add two box frame supports at MS bypass loop in Turbine Building
3-02-3870SH3 3-02-3870SH4	Add lateral guides inside 2 G-line wall sleeves
3-02-M778ASH26 3-02-M778ASH27	Add new supports for rerouting of MS drain line
3-3001-H86 3-3001-H89	Remove existing pipe supports

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Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 13-2 QCNPS

SUPPORT NUMBER	MODIFICATION DESCRIPTION
QCNPS Unit 1 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
1-3001B-20-S1	Replace snubber assembly, replace support structure by tube steel members
1-3001B-20-S2	Relocate pipe clamp to accommodate new clamp for 1-3001B-20-S1
1-3001C-S2	Add new welds, replace a snubber
1-3001D-R1	Add new welds, replace support member
1-3001-988D-8-1 1-3001-988D-8-2 1-3001-988D-8-3 1-3001-988D-8-4	Add special LISEGA Clamps and horizontal and vertical struts to main steam lines
1-3059-988D-8-5 1-3059-988D-8-6	Add new supports for rerouting of MS equalizing line
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates
QCNPS Unit 2 - TAP SUPPORT MODIFICATIONS	
2-1810-07	Reset spring can displacements
2-1810-35	Add stiffener plate
QCNPS Unit 2 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
2-3001A-R4	Add stiffeners to existing steel beam
2-3001B-S2	Add new welds, strengthening structural beam
2-3001B-R1	Replace existing strut
2-3001C-R1	Replace existing strut
2-3001C-S2	Replace entire support structure by tube steel members and add stiffeners to steel beam
2-3001-1020D-6-1 2-3001-1020D-6-2 2-3001-1020D-6-3 2-3001-1020D-6-4	Add special LISEGA Clamps and horizontal and vertical struts to main steam lines
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates, replace bolting at *5* connections (EL. 593)

Attachment A
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References:
1. Licensing Topical Report, “Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate,” NEDC-32424P-A, Class III, February 1999

2. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, “Request for License Amendment for Power Uprate Operation,” dated December 27, 2000

3. Letter from U. S. NRC to O. D. Kingsley (Exelon Generation Company, LLC), “Issuance of Amendments; Increase in Reactor Power, Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2,” dated May 4, 2001

Attachment B
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Affidavit for Withholding Portions of Attachment A from Public Disclosure

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General Electric Company

AFFIDAVIT

I, George B. Stramback, being duly sworn, depose and state as follows:

(1) I am Project Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Attachment 1 to letter GE-DQC–EPU-01-466, *Mechanical RAIs*, (GE Proprietary Information), dated August 7, 2001. The proprietary information is delineated by bars marked in the margin adjacent to the specific material in the Attachment 1, *GE Response to NRC Mechanical RAIs.*

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in both paragraphs (4)a. and (4)b., above.

(5) The information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains further details regarding the GE proprietary report NEDC-32961P, *Safety Analysis Report for Quad Cities 1 & 2 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, and NEDC-32962P, *Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, which contain detailed results of analytical models, methods and processes, including computer codes, which GE has

developed, obtained NRC approval of, and applied to perform evaluations of transient and accident events in the GE Boiling Water Reactor ("BWR").

The development and approval of these system, component, and thermal hydraulic models and computer codes was achieved at a significant cost to GE, on the order of several million dollars.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GE asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GE would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

George B. Stramback, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 7th day of August 2001.

George B. Stramback
General Electric Company

Subscribed and sworn before me this 7th day of August 2001.

TERRY J. MORGAN
Commission # 1304914
Notary Public - California
Santa Clara County
My Comm. Expires May 18, 2005

Notary Public, State of California

Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (non-proprietary version)

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Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 4, 5, 6, 8, 9, 11 (Parts A, B, C, and E), 12 (Parts A, B, and C), 13, and 14. Responses to NRC Questions 1, 2, 3, 7, 10, 11D, and 12D will be provided separately.

Question

4. A. In reference to Sections 3.3.2 and 3.3.4, provide a discussion of the methodology, assumptions and loading combinations used for evaluating the reactor vessel and internal components with regard to the stresses and fatigue usage for the power uprate.

B. Were the analytical computer codes used in the evaluation different from those used in the original design-basis analysis? If so, identify the new codes used and provide your justification for their use by specifying how were these codes benchmarked for such applications.

Response

A. The methodology, assumptions and loading combinations used for evaluating the reactor vessel and internal components are described in Reference 1, Appendix I, "Methods and Assumptions for Vessel and Components Evaluations."

B.

Question

5. In Section 4.1.2.3 regarding the subcompartment pressurization, you stated that the increase in actual asymmetrical loads on the vessel, attached piping and biological shield wall, due to the postulated main steam and feedwater pipe breaks in the annulus between the reactor vessel and biological shield wall is minor. You also indicated that the biological shield wall and component designs remain adequate, because there is sufficient pressure margin available.

Discuss quantitatively how will the biological shield wall and the reactor vessel and internals be affected by the proposed power uprate as a result of increase in the applied asymmetrical pressurization and jet loads.

Response

PUSAR Section 4.1.2.3, "Subcompartment Pressurization," discusses asymmetrical loads without specifically referring to a main steam or feedwater line break. A postulated rupture of a recirculation suction line was previously evaluated for both Dresden Nuclear Power Station (DNPS) and Quad Cities Nuclear Power Station (QCNPS) to assess the structural capability of the biological shield wall.

For both DNPS and QCNPS, the largest line which has the safe end located in the annulus region between the reactor vessel and the biological shield wall is a 4 inch jet pump instrument line. The maximum calculated wall differential pressure (i.e., 1 psid) for this postulated break is well below the structural capability of the wall.

These previous evaluations were used as a basis to quantify the changes expected due to EPU. A simplified subcompartment pressurization model of the DNPS and QCNPS annulus region was developed and expected mass and energy releases at pre-EPU and EPU conditions were determined.

Recirculation suction line break mass and energy releases at pre-EPU and EPU conditions were calculated using the standard General Electric (GE) methods, using inputs from the reactor heat balances at both pre-EPU and EPU conditions.

The following assumptions were used to determine the pre-EPU and EPU mass and energy releases.

- Initial mass release rates (i.e., inventory period) are based on Moody saturated critical flow, with a flow multiplier of 1, through the break area from both the pipe side and reactor side of the break.
- Energy release rates are based on the core inlet enthalpy.
- After the initial blowdown (i.e., inventory period) the flow is conservatively based on the Henry-Fauske subcooled critical flow, rather than the Moody subcooled critical flow, from the nozzle area on the reactor side of the break. The flow from the pipe side of the break is based on the total area of 10 jet pump nozzles plus the reactor water clean up (RWCU) line area.
- The safe end weld is within the biological shield wall penetration. This penetration is included in the evaluation to account for a flow split between the annulus and the drywell.

The resulting maximum incremental increase in mass release due to EPU was determined to be 6% for DNPS and 6.2% for QCNPS. The maximum incremental increase in energy release due to EPU was determined to be 5.5% for DNPS and 5.8% QCNPS.

Benchmark subcompartment pressurization analyses of the DNPS and QCNPS annulus region were performed using the COMPARE computer code and pre-EPU mass and energy releases for a recirculation suction line break. The same model was rerun using mass and energy releases calculated at EPU conditions.

The biological shield wall pressurization has been evaluated for the effects of these small increases in mass and energy. An analysis was performed to determine the effect on annulus pressure expected for the above changes in mass and energy releases. This resulted in a minor reduction in pressure margin. The study resulted in an increase of 0.9 psi for DNPS and 1.2 psi for QCNPS in the maximum calculated biological shield wall differential pressure. The incremental increase in annulus pressure was applied to results of the previous evaluations dicussed above. The pressure margins are provided below.

PARAMETER	DNPS	QCNPS
Annulus differential pressure at which biological shield wall failure would begin (psid)	41	46
Maximum annulus pressure from a recirculation line break (psid)	36	38
Pre-uprate margin (psid)	5	8
Incremental change due to EPU (psi)	0.9	1.2
EPU margin (psid)	4.1	6.8

The jet loads are evaluated in PUSAR Section 10.1.2, "Pipe Whip and Jet Impingement." The review shows that there is no change in the operating pressure of high energy main steam piping. Thus, the jet impingement load evaluation results remain unchanged for the main steam piping system due to EPU. For the feedwater piping, the internal pressure increase is less than 10 psi. The less than 10 psi change in the internal pressure represents an approximately 1% change that was judged to be insignificant for jet impingement load evaluation.

Question

6. In the evaluation of the reactor jet pumps in Section 3.3.4, you stated that additional engineering evaluations will be performed to determine if the jet pump riser brace will be susceptible to vibration from the recirculation pump vane passing frequency (VPF). The evaluations will determine if modifications are required to alter the natural frequency of the jet pump braces.

A. Provide your evaluation associated with the possible VPF vibrations due to the EPU.

B. Confirm whether and how your evaluation for the structural integrity of jet pumps will be affected by the VPF vibrations due to EPU at DNPS and QCNPS.

Response

A. An extensive test program was conducted at the GE test facilities in San Jose from February to July 2001 to determine the natural frequencies of the DNPS Unit 2 and Unit 3 riser braces. The DNPS Unit 3 riser braces are representative of the QCNPS Units 1 and 2 riser braces. A full scale mockup of the jet pump riser pipe and riser brace was constructed and set up to determine the residual loads and natural frequencies of the riser brace leaves in air and also while submerged under water. A total of 26 strain gages and 6 accelerometers were installed and the natural frequencies of these jet pump components were computed from the dynamic response to impacts from an instrumented hammer. The results of the test program showed that the reactor recirculation system VPF during EPU operation is well removed from the riser brace natural frequencies and no modifications are required to alter the natural frequency of the riser braces.

B. The VPF vibrations at non-resonant conditions were considered in the evaluation of the jet pumps. The above described test was conducted to see if there is any potential for resonance of the riser brace leaves due to VPF at EPU conditions. Since the VPF is well removed from the riser brace leaf natural frequency, the response due to VPF is small and the existing evaluation is not affected.

Question

8. A. In reference to Section 3.5, provide a discussion of the methodology and assumptions used for evaluating the reactor coolant pressure boundary piping systems for the proposed power uprate.

B. Provide the calculated maximum stresses and fatigue usage factors at the current design basis and the proposed power uprate conditions, corresponding critical locations and piping systems, allowable stress limits, and the code and code edition used in the evaluation for the power uprate. If different from the Code of record, justify and reconcile the differences.

Response

A. The reactor coolant pressure boundary (RCPB) piping evaluated includes the following piping systems.

- Reactor recirculation (RR) system
- Main steam (MS) piping inside containment
- Branch piping from RR and MS systems, including safety and relief valve discharge lines, shutdown cooling system (residual heat removal (RHR) for QCNPS), RWCU, low pressure coolant injection (LPCI), and others
- Reactor pressure vessel (RPV) head vent, RPV bottom drain line, and/or isolation condenser (IC) (Reactor Core Isolation Cooling (RCIC) for QCNPS)
- MS drain lines
- Small bore piping attached to these systems

Existing design and licensing basis documents, such as design specifications and piping stress reports, were reviewed to determine the design and analytical basis for these piping systems. The proposed uprate parameters of the RCPB piping systems were compared with the existing analytical bases to determine any increases in temperature, pressure, and flow due to the uprate conditions. During the evaluation process, the original code of record, code allowables, and the same analytical techniques were used. No new assumptions or computer codes were used except for in the evaluation of the MS lines as described in the response to Question 13A.

For the majority of these systems, it was determined that there are no changes in the analysis parameters. The RR system was determined to be subject to a slight increase in temperature, but less than the acceptance criteria outlined in the response to Question 9A. The MS piping will not experience an increase in temperature. However, a significant increase in flow will be seen, which will have an impact on the turbine stop valve (TSV) closure transient. A detailed description of the methodology and assumptions used in the evaluation of the MS system is provided in the response to Question 13A. Some of the branches off the RCPB piping (i.e., core spray (CS), LPCI, etc.) were also found to experience temperature increases due to long term post-LOCA conditions in which water is being drawn from the suppression pool (i.e., torus). These systems were evaluated with the large bore torus water piping systems and the methodology and assumptions used in those evaluations are described in the response to Question 9A. All other RCPB piping systems are either not impacted by EPU, or the changes are within acceptance criteria.

B. The majority of the RCPB piping systems are designed to American National Standards Institute (ANSI) B31.1.0, 1967 requirements, which are not subject to fatigue requirements. In addition, the RCPB piping is under the jurisdiction of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section I, 1965 Edition, through Summer 1966 Addenda including Code Cases N-1 thru N-3 and N-7 thru N-11. In accordance with these codes and code cases, fatigue is not part of the design or licensing basis for these systems. For DNPS only, the one exception is the RR system piping for DNPS Unit 3, which was replaced in the mid 1980s. The stress analysis for Class I piping covered by the scope of the RR pipe replacement project was performed in accordance with ASME Code, Section III, Subsection NB, 1980 Edition, including the Summer 1982 Addenda, which includes fatigue requirements. The RR system piping was determined to have a only minor increase in the temperature, which was considered negligible. Any small increase in stresses due to the slight temperature increase is bounded by inherent conservatisms in the existing analysis. Therefore, the calculated maximum stresses and fatigue usage factors are unchanged as a result of the proposed uprate. The critical locations and piping systems, allowable stress limits, and the code and code edition used are also unchanged.

Question

9.A. Provide a summary of your evaluation of the pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers and anchors at the power uprate condition. The evaluation should include the methodology, assumptions, and the results of evaluation for the critical piping systems affected by the proposed power uprate.

B. Were the analytical computer codes used in the evaluation different from those used in the original design-basis analysis? If so, identify the new codes and provide your justification for their use by specifying how these codes were benchmarked for such applications.

Response

A. Operation at EPU conditions may increase piping stresses caused by higher operating temperatures, pressures and flow rates. Additionally, piping components (i.e., pipe supports, equipment nozzles, etc.) may be potentially subjected to increased loadings due to the EPU.

The piping system evaluations for power uprate were performed by determining "change factors" for the changes in thermal, pressure, flow rate, and total design load conditions. This method is based on determining a "change factor" by conservatively comparing the ratio of power uprate temperature, pressure and flow conditions to the corresponding pre-EPU conditions. The method (described below) used to evaluate DNPS and QCNPS is the same method used on several other power uprates - most recently for the Turkey Point, Byron and Braidwood power uprates. The recent Byron and Braidwood NRC Safety Evaluation for power uprate (Reference 3) concluded that, "The staff finds the methodology to be acceptable considering the conservatism in the calculation of the scaling factors for the power uprate stress and loads."

This method is based on determining a "change factor" by conservatively comparing the ratio of power uprate temperature, pressure and flow conditions to the corresponding pre-uprate conditions.

Where the "change factor" is less than or equal to 1.0, the pre-EPU (i.e., existing) conditions envelop or equal the power uprate conditions and no further review is performed.

For minor changes resulting in a "change factor" between 1.0 and 1.05 (i.e., 5%), the increase was considered acceptable since the small increase is offset by conservatism inherent in the analytical methods used to calculate the existing stresses and loads. The conservatism include, but are not limited to, the industry practice of enveloping multiple operating conditions and modeling pipe supports without consideration of gaps between piping and supports. Pressure effects are considered in conjunction with other loading conditions which are unchanged by the EPU (e.g., weight, seismic) thus the overall effect of the pressure change factor is reduced. Therefore for "change factors" between 1.0 and 1.05, the existing stress and load values were considered to be acceptable and remain within allowable limits.

For "change factors" greater than 1.05, simple and conservative evaluations were performed to address the specific increase in stress and load values. Where the simple evaluation yielded a resultant stress ratio (i.e., calculated / allowable) that was less than or equal to 1.0, the resultant stress remains acceptable. For those conditions where the resultant stress ratio is greater than 1.0, the calculations were revised and/or piping support modifications were performed to bring the stress at EPU conditions within allowable limits.

The thermal "change factor" was based on the ratio of the thermal power uprate to pre-thermal power uprate operating temperature. That is, the thermal change factor is $(T_{uprate}-70^\circ F)/(T_{pre-uprate}-70^\circ F)$. Using this method for the thermal change factor, evaluations resulted in a bounding evaluation of the thermal impact on piping stresses and loads.

Similarly, the pressure "change factor" was determined by the $P_{uprate}/P_{pre-uprate}$ ratio and the flow rate "change factor" was determined by the $Flow_{uprate}/Flow_{pre-uprate}$ ratio. The total design load change factor is the total combined load associated with EPU conditions divided by the allowable design load, and was determined by the following formula:

[Dead Weight (DW) + $\text{Pressure}_{\text{uprate}}$ + $\text{Thermal}_{\text{uprate}}$ + $\text{TransientLoad}_{\text{uprate}}$ + Seismic] / Design $\text{Load}_{\text{analyzed}}$.

Thermal changes were found to be the most significant, primarily for systems using the suppression pool as a water suction source during long term post-LOCA conditions. No changes to the suppression pool loads (i.e., pool swell, condensation oscillation, chugging and SRV discharge) will result from the EPU because previous load definitions were determined to be bounding. Pressure changes were typically found to be negligible and were unchanged for most systems. There is a slight increase in predicted design basis accident (DBA) pressures inside the torus. However, most torus attached piping systems and components were previously analyzed for the maximum intermediate break analysis pressures, which bound even the new DBA pressures. Flow changes were found to be significant only for the MS and feedwater/condensate systems. A detailed evaluation of the MS system was performed for the increased flow rate and is discussed in more detail in the response to Question 13A.

All piping systems subject to changes in temperature, pressure or flow were screened to determine the impact on the piping and piping components (i.e. supports, penetrations, equipment nozzles, etc.). Piping systems subjected to minor operating condition increases due to EPU were excluded from a detailed evaluation, as follows.

Thermal load increases of up to 5% (i.e., change factors between 1.00 and 1.05), were considered acceptable since these increases are offset by conservatism in analytical methods used to calculate the existing stresses and loads. Conservatisms include the enveloping of multiple thermal operating conditions and not considering pipe support gaps in the thermal analyses.

Furthermore, in accordance with industry practice, piping systems that have operating temperatures less than 150°F did not require evaluation for thermal change effects.

Pressure load increases up to 5% were considered acceptable due to margins in piping wall thickness.

Transient load increases up to 5% resulting from EPU related fluid flow rate changes were considered acceptable due to conservatism in load combinations (i.e., transient loads are combined with other conservative loads such as thermal and seismic).

Total design load increases of 5% were considered minor and acceptable by engineering judgment due to inherent conservatism in piping analysis methodology, as previously described.

The total design load criteria was not used for drywell steel, corner room steel, and/or flued head anchors without reviewing their qualification documentation to ensure that similar reasoning to this criteria had not been previously invoked for other load increases.

If the increases described above exceeded 5%, the analyzed margin between design load and the allowable load prior to uprate was used to justify the increases for uprate conditions (e.g., if the load increased by 15%, but the piping component analysis showed a 20% margin to allowable, the component was considered acceptable).

If the load increase on a piping component was greater than the calculated available margin, then a detailed evaluation of the component was performed to evaluate the adequacy of the component for EPU conditions. If the detailed evaluation could not justify the increased EPU loads in accordance with the previously defined acceptance criteria, a modification was designed for that component such that the modified component would meet that acceptance criteria. A description of the modifications required to qualify the piping and piping components for EPU conditions is provided in the response to Question 13B.

All piping systems and piping components with changes in temperature, pressure or flow rate were screened for impact by EPU. If the change factor for the piping system was less than 1.05, the whole system, including the piping components (i.e., supports, penetrations, equipment nozzles, etc.), was considered acceptable. If any of the change ratios exceeded 5%, each piping component was reviewed independently.

The evaluation methodology used to assess impact of the long term post-LOCA temperature increase on torus water piping system components (piping components in systems pumping or exposed to the torus water) is provided in more detail below, by component type:

Pipe Stress
The basic approach for the pipe stress evaluation was to scale up the existing Level A ASME Equation 10 pipe stresses by the thermal change ratio. The revised stress was then compared to the allowable pipe stress associated with the post-LOCA thermal condition. The application of ASME and B31.1 for the EPU pipe stress evaluations is consistent with the existing design and licensing basis.

The allowable pipe stress for post-LOCA conditions was based on the code of record for each piping system for one time secondary loads (e.g., single non-repeated anchor movement). For ASME piping, the allowable stress was taken as 3 S_h (equal to 45,000 psi for A-106 Gr. B piping). For B31.1 piping, the allowable was taken as 1.8 S_h (equal to 27,000 psi for A-106 Gr. B piping). For B31.1 piping, as an alternate, an allowable of 3 S_h minus the actual deadweight (DW) and pressure stresses is allowed by Section 102.3.2d of B31.1.

Rigid Pipe Supports
Rigid supports were categorized as those supports that rigidly support both static and dynamic loads and include rod hangers where applicable, struts, guides, and piping anchors, etc. The basic approach was to calculate a revised post-LOCA load combination of DW plus EPU thermal (T) (i.e., thermal expansion plus thermal anchor movement) plus safe shutdown earthquake (SSE) plus EPU torus displacement (TD). This load combination was classified as a

Level D or faulted load combination. Therefore, a revised interaction coefficient (IC) (i.e., actual stress divided by allowable stress) was calculated by multiplying the maximum IC in the existing calculation by the total design load change factor defined as the new post-LOCA load combination (DW+T+SSE+TD) divided by the largest peak qualified load. In addition, for supports subjected to frictions loads (i.e., guide supports), or supports with integral welded attachments, additional evaluations were performed.

Snubbers
Since snubbers do not resist thermal loads, the new EPU thermal conditions will not affect the snubber loads. The thermal displacement will increase however, so there is a potential for a top out or bottom out condition associated with the increased thermal displacements from EPU. In the late 1980s, allowable cold setting ranges were determined for each snubber to ensure that sufficient travel was available such that the snubbers would not bottom or top out on their range during thermal expansion. Included in this range calculation was a minimum of a ½ inch travel margin provided on each end of the range. Therefore, a minimum of ½ inch of travel is available to handle additional thermal expansion above and beyond the current design displacements. A generic evaluation was performed, which concluded that the increase in thermal displacements due to the EPU would not exceed the ½ inch available travel.

In addition, the increased displacement will cause an increase in the swing angle for snubbers and other pinned supports. A generic evaluation was performed, which concluded that the increase in swing angles due to EPU conditions is minor and will not impair the functionality of the pinned type supports.

Spring Hanger Supports
For each affected spring hanger, the increased vertical thermal displacement was compared to the available displacement to top/bottom-out conditions. If the additional displacement exceeded the available displacement by more than 5%, then a modification was issued to reset or replace the existing spring can. The increase/decrease in the spring hanger load due to movement change is considered to be negligible.

Displacements at Interferences
Some piping models have displacement checks at certain locations where there may be interferences with nearby structures (i.e., slab or wall penetrations, nearby plant equipment, etc.). The locations that were impacted were evaluated to make sure the revised thermal displacements did not result in damaging contact with these interferences.

Flanges
Some of the piping models have in-line flanges that have been evaluated for piping moments. These moments in the piping system are affected by the increase in temperature for these lines. For the affected flanges, revised thermal moments were calculated for the flanged joints and compared to the previously calculated allowables.

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Valves

The stresses in valve bodies were already enveloped by the stresses reported for the piping, so these valves were covered in the piping stress evaluation. For valves with extended operators (i.e., motor operated valves (MOVs)), the stresses are a function of the valve acceleration and are not affected by increased thermal loads.

Containment Penetrations

Some of the piping systems penetrate the primary containment boundary (i.e., the torus or the drywell). At these penetrations, the containment shell is evaluated for the local stresses in the vicinity of the penetration due to the reactions at the penetration. The total stress in the containment shell is a combination of the local stresses due to the reaction loads from the piping, combined with the global shell stresses due to conditions inside containment. The revised post-LOCA forces and moments were calculated for all six degrees of freedom and compared to the previously qualified loads. In some cases, revised combined stresses in the containment were calculated and compared to the allowable stresses.

Equipment Nozzles

The existing design basis for piping loads on equipment is that the nozzles and casings are considered acceptable if the attached piping stress at the nozzles meets the code requirements for the piping. For certain equipment, a seismic qualification utility group (SQUG) type evaluation had previously been performed, where the equipment anchorage was evaluated considering the piping reaction loads. This approach was extended to cover non-SQUG equipment such as the core spray (CS) pumps. The affected equipment included the LPCI and CS pumps and the LPCI heat exchangers at DNPS and the RHR and CS pumps and the RHR heat exchangers at QCNPS. If the loads on this equipment increased by more than 5%, the equipment anchorage was re-evaluated. In some cases, it was concluded that certain equipment is bounded by other similar equipment that had been previously evaluated and accepted (i.e., identical equipment with higher nozzle loads).

Reactor Nozzles

Some of the piping systems tie directly into reactor nozzles. At these nozzles, an evaluation was performed to determine the impact of the nozzle reaction loads on the RPV. The revised stresses in the RPV nozzles were calculated for EPU conditions and compared to the previously calculated allowable stresses. The nozzles were also previously evaluated for fatigue considerations. Since the EPU post-LOCA thermal condition is a one-time event, its impact on the fatigue analysis of the nozzle was determined to be negligible.

Results

The results of the piping evaluations are provided in Tables 9A-1, 9A-2, 9A-1QC, 9A-2QC, 9A-3, 9A-4, 9A-3QC, and 9A-4QC. All large bore (i.e., > 4" normal pipe size (NPS)) torus water piping systems were evaluated for the effect of increased operating temperatures and pressures. The resulting pipe stress for each piping system and the corresponding allowable stresses are shown in Tables 9A-1, 9A-2, 9A-1QC, and 9A-2QC. The scope of the small bore torus water piping systems that were evaluated for EPU conditions included small bore piping directly attached to the torus and small bore piping connected to large bore piping that is directly attached to the torus. Also, small bore lines attached to large bore lines that are not torus attached but transmit torus water during the long term post-LOCA mode were evaluated. The current and resulting EPU pipe stress for each small bore piping system and the corresponding allowable stresses are shown in Tables 9A-3, 9A-4, 9A-3QC, and 9A-4QC.

Piping components (i.e., pipe supports, etc.) were evaluated as described above. In some cases modifications were required to ensure the components could handle the increased thermal loads due to the EPU. If modifications were required, the stresses shown in the tables reflect the post-modification calculated stresses. A summary of all the piping component modifications is provided in the response to Question 13B.

B. In some instances different software codes were used in the evaluation of various piping systems and piping components (i.e., pipe supports) when detailed analysis was required to evaluate a system or component. The following software codes were used, along with a description of how they were benchmarked.

Piping Analysis Software
PIPSYS was used for piping analysis for certain torus water piping systems when a more detailed analysis was required. These piping systems were previously analyzed using the proprietary software PISTAR. In these cases PIPSYS was only used to analyze non-Mark I load cases (i.e., deadweight, seismic, and thermal). PIPSYS is a widely used piping analysis software which was procured from Sargent & Lundy (S&L) and has been verified and validated for use on nuclear projects in accordance with the S&L Quality Assurance Program.

NUPIPE-SWPC was used for piping analysis for certain torus water and main steam piping systems when a more detailed analysis was required. NUPIPE-SWPC is suitable for use in nuclear safety related applications and has been benchmarked to industry standards and codes. It is documented, reviewed, approved and controlled in accordance with the Stone & Webster Quality Assurance Program.

Frame Analysis Software
GT-STRUDL and PC-PREPS were used for frame analysis for certain torus water and main steam piping supports when a more detailed analysis was required. Some of these supports were previously analyzed using GENSAP or using manual calculations. GT-STRUDL and PC-PREPS are suitable for use in nuclear safety related applications and have been benchmarked to industry standards and codes. They are documented, reviewed, approved and controlled in accordance with the Stone & Webster Quality Assurance Program.

STAAD-III was used in the frame analysis of certain MS pipe supports inside the drywell. These supports were previously analyzed manually. STAAD-III is a widely used analysis software which has been verified and validated for use on nuclear projects in accordance with the S&L Quality Assurance Program.

Baseplate Analysis Software
NPLATE was used for baseplate analysis for certain torus water pipe supports. Some of these supports were previously analyzed using SDAL or BASEPLATE II software or by hand calculations. NPLATE is a widely used baseplate analysis software which was procured from Duke Engineering and was verified and validated for use on nuclear projects as part of the Duke Engineering Quality Assurance Program.

Fluid Transient Forcing Function Development Software
STEHAM was used for fluid transient forcing function development for main steam piping when a more detailed analysis was required. STEHAM is suitable for use in nuclear safety related applications and has been benchmarked to industry standards and codes. It is documented, reviewed, approved and controlled in accordance with the Stone and Webster Quality Assurance Program.

Integral Welded Attachment Analysis Software
ANSYS, PILUG, PITRUST and PITRIFE were used for integral welded attachment analysis for certain torus water and main steam piping supports when a more detailed analysis was required. ANSYS, PILUG, PITRUST and PITRIFE are suitable for use in nuclear safety related applications and have been benchmarked to industry standards and codes. They are documented, reviewed, approved and controlled in accordance with the Stone and Webster Quality Assurance Program.

Question
11. A. Discuss the functionality of safety-related mechanical components (i.e., all safety-related valves and pumps, including air-operated valves (AOV) and safety and relief valves) affected by the proposed power uprate to ensure that the performance specifications and technical specification requirements (e.g., flow rate, close and open times) will be met for the proposed power uprate.

B. Confirm that safety-related air operated valves (AOVs) and motor-operated valves (MOVs) will be capable of performing their intended function(s) following the proposed power uprate including such affected parameters as fluid flow, temperature, pressure and differential pressure, and ambient temperature conditions.

C. Identify the mechanical components that were not evaluated at the uprated power level.

E. Provide an evaluation of the effect of increased temperature due to power uprate on thermally-induced pressurization of piping runs penetrating the containment that were evaluated in response to Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions."

Response

A. Plant mechanical systems, including safety-related mechanical components, were evaluated to assess operating condition changes at EPU. As described in Reference 1, some plant systems were determined to be not impacted or only slightly impacted by EPU. For the remaining plant systems, further evaluations were performed to ensure the adequacy of the system components to operate as required at EPU conditions. This review included all safety-related mechanical components (e.g., pumps and valves) within the system. Safety-related pumps, safety relief valves and other components were determined to be adequately designed for operation at EPU conditions.

Refer to the response to Question 11B for further discussion on AOVs and MOVs.

B. In addition to the mechanical component review discussed in the response to Question 11A, AOVs and MOVs were reviewed in more detail. All MOVs in the Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing And Surveillance," program have been evaluated for EPU process and ambient conditions changes, including parameters such as fluid flow, temperature, pressure, differential pressure and ambient temperature. These evaluations confirmed that the existing analysis for each MOV bounds the EPU conditions.

Safety-related AOVs have been categorized into an AOV Program and evaluated utilizing the Joint Owners' Group (JOG) methodology. All AOVs included in this program have been evaluated for EPU process and ambient conditions changes, including parameters such as temperature, pressure, flow and differential pressure, similar to that previously described for MOVs to confirm the AOVs operate as required after EPU implementation.

C. There is no listing of the mechanical components that were not specifically evaluated or determined not to be impacted by EPU. However, PUSAR Section 6.8, "Systems Not Impacted by EPU," identifies those systems that were generically dispositioned as unaffected by EPU in Reference 1, Section J, "Methods and Assumptions for System Equipment Evaluation."

For systems that are impacted by EPU, the components affected are discussed on a system by system basis throughout the PUSAR.

E.

DNPS

Piping runs penetrating the containment that were evaluated in the response to GL 96-06 were confirmed adequate for uprate conditions by one of the following methods.

- Penetration piping with relief valves. Relief valves set pressures are not affected by uprate conditions. Existing relief capacities are much greater than required, enveloping any slight increase in relief capacity required from heat transfer to the isolated section due to EPU.

- Penetration piping with a bypass. Piping runs containing a bypass line with a spring check valve are not affected by uprate conditions for thermal overpressurization.
- Other water-filled penetration piping. In some cases, EPU conditions slightly increase the heat transfer to the isolated water-filled piping. Adequate conservatism exists in the original design to accommodate the resulting slight increase in internal pressure.

QCNPS
Piping runs penetrating the containment that were evaluated in the response to GL 96-06 were confirmed adequate for uprate conditions by one of the following methods.

- Penetration piping with relief valves. Relief valves set pressures are not affected by uprate conditions. Existing relief capacities are much greater than required, enveloping any slight increase in relief capacity required from heat transfer to the isolated section due to EPU.
- Other water-filled penetration piping. In some cases, EPU conditions slightly increase the heat transfer to the isolated water-filled piping. Adequate conservatism exists in the original design to accommodate the resulting slight increase in internal pressure.

Question
12. A. In reference to Section 3.11, provide a summary addressing your evaluation of the effects of the proposed power uprate on the balance-of-plant (BOP) piping, components, and pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers and anchorages.

B. Provide the calculated maximum stresses and fatigue usage factors for the most critical BOP piping systems, the allowable limits, the code of record and code edition used for the power uprate conditions. If different from the code of record, justify and reconcile the differences.

C. In Appendix G of the submittal, you indicated that some feedwater heater relief valves will be adjusted or replaced and the heaters will be rerated to compensate for the increased feedwater flow and the associated pressure change. You also indicated that condenser tube staking is planned for the main condensers to provide adequate protection against tube vibration damage at uprated power conditions. Provide a summary of your evaluation of the main condenser tubes at the uprated condition.

Response
A. The BOP piping systems include all other affected piping systems not included in the piping systems addressed in the response to Questions 8, 9, and 13. These systems were evaluated using the same methodology and criteria discussed in the response to Question 9A. With the exception of MS, which is described in Question 13A, most of these BOP systems will not experience significant changes in operating conditions due to EPU. A description of the piping systems examined, and the results of these evaluations are provided in Table 12A-1.

B. The calculated maximum stresses and fatigue usage, the allowable limits, the code of record and code edition used for the EPU conditions factors for the most critical piping systems are provided in the response to Questions 8, 9, and 13. The remaining BOP affected systems passed the screening criteria discussed in the response to Question 9A, and no new analyses were required.

C.
DNPS
The main condenser tubes were evaluated at EPU conditions to determine which areas of the condenser tube bundle would be subject to potentially damaging tube vibration and to determine the extent and length of the stakes required to prevent such damage. Heat transfer relations were used to determine the overall performance of the condenser at the uprated condition. Steam flow velocities within the condenser were then determined based on the calculated heat transfer performance of the condenser. These velocities were used to evaluate the vibration criteria established from H. J. Conners, "Fluid-Elastic Vibration of Heat Exchanger Tube Arrays."

The plots of the Conners vibration parameters analyzed at winter conditions (i.e., worst case) indicate areas susceptible to fluid-elastic vibration. From this, the location and length of required stakes were determined.

QCNPS
The main condenser tubes were evaluated at the uprated conditions to determine which areas of the condenser tube bundle would be subject to potentially damaging tube vibration and to determine the extent and length of the stakes required to prevent such damage. Heat transfer relations were used to determine the overall performance of the condenser at the uprated condition. Steam flow velocities within the condenser were then determined based on the calculated heat transfer performance of the condenser. These velocities were used to evaluate the vibration criteria established from H. J. Conners, "Fluid-Elastic Vibration of Heat Exchanger Tube Arrays."

The plots of the Conners vibration parameters analyzed at winter conditions (i.e., worst case) indicate areas susceptible to fluid-elastic vibration. From this, the location and length of required stakes were determined. The currently installed staking was then compared to the stake locations and lengths determined in the analysis and was found to be adequate. No additional staking will be installed.

Question
13. A. In reference to Sections 3.5 and 4.1.2, provide a discussion of the evaluation of piping systems attached to the torus shell, vent penetrations, pumps, and valves, that are affected by increased torus temperature and changes in LOCA dynamic loads (pool swell, condensation oscillation, and chugging) and increased temperature and flow in the main steam and feedwater systems due to the proposed power uprate.

B. Identify supports and piping systems that require modifications as a result of the proposed extended power uprate.

Response

B. For piping systems other than MS, refer to the responses to Questions 8, 9, and 12.

The EPU does not affect design basis loads for the MS system. However, the MS system flow will increase by approximately 20% for EPU. A review of the increase in flow related loads associated with EPU indicates that piping loads due to the dynamic effects of the TSV fast closure, which is not included in the design basis loads, results in significant loads for the MS piping and supports.

DNPS and QCNPS are pre-General Design Criteria Plant (GDC) plants and were designed to USAS B31.1 – 1967, which required consideration of the most severe condition of coincident pressure, temperature, and loading. B31.1 – 1967 required that the plant transient dynamic load for safety valve opening be included in the design requirements. The Standard Review Plan (SRP), Section 10.3, "Main Steam Supply System," Revision 3, stated that main steam systems must be designed to withstand the effects of rapid valve closure. However Subsection V, "Implementation," of SRP Section 10.3 states that currently licensed plants (i.e., prior to 1984) do not need to adhere to this requirement. Thus, neither the GDC nor SRP requirements regarding consideration of transient dynamic loads due to TSV closure have been applied to DNPS or QCNPS.

Even though consideration of TSV loads was determined to be beyond the design basis, it is prudent to address these loads. The EPU evaluation approach for the TSV loads is based on an acceptance criteria for the TSV loads which are less restrictive than the current application of the ASME and American Institute for Steel Construction (AISC) codes, but which ensure that no permanent deformation of the piping, piping supports or supporting structural steel will occur as a result of the event.

Under EPU conditions the TSV closure loads were analyzed and modifications were implemented to ensure that the TSV closure does not result in MS piping failure. Since there is no current licensing basis for the acceptance criteria for the TSV loads, load combinations and acceptance criteria for the TSV loads were developed for the EPU evaluations. The MS piping, pipe supports, and supporting structures were evaluated for the TSV fluid transient loads in combination with pressure, deadweight, thermal, safety relief valve (SRV), and pipe break loads, as appropriate. Since a seismic event may cause a unit trip and a TSV closure, the TSV transient loads were also considered concurrent with applicable seismic loads. Since the TSV closure event is considered beyond the current licensing basis, a TSV event was considered to occur concurrently with the SSE only. The evaluation method is to demonstrate pressure boundary integrity of the piping and associated member/component evaluated to ensure that no gross deformation or integrity failure occurs. Also, due to the time relationships between the significant loads resulting from TSV, SRV discharge, and pipe break events (i.e., LOCA), no combination of these loads is required.

To demonstrate piping pressure boundary integrity subsequent to a TSV closure event, the piping, pipe supports and supporting structures were evaluated for the following additional loading combinations (LC).

Piping:

LC 1 Dead Load + Pressure + TSV Loads
LC 2 Dead Load + Pressure + $[(\text{TSV Loads})^2 + (\text{SSE Loads})^2]^{1/2}$

Pipe Supports and Pipe Support Structures:

LC 3 Dead Load + Operating Thermal Loads + TSV Loads
LC 4 Dead Load + Operating Thermal Loads + $[(\text{TSV Loads})^2 + (\text{SSE Loads})^2]^{1/2}$

The TSV fluid transient loads were generated utilizing the representative and bounding effective closing time for the TSV. For dynamic load combinations, oscillator (i.e., piping system) damping were considered to be 2% when considering TSV alone (i.e., LC 1) and 3% when combined with seismic (i.e., LC 2), in accordance with guidance contained in Reg. Guide 1.61, "Damping Values for Seismic Design of Nuclear Power Plants." Seismic damping values are based on the values stipulated in the Updated Final Safety Analysis Report (UFSAR).

For evaluation of the supporting drywell steel, where supports from different main steam lines are attached to the same drywell steel, the TSV loads were combined by the square root of the sum of the squares (SRSS) method. This is due to the variation in actuation time, which results in the pressure wave for different MS lines being out-of-phase with the peak loads occurring at different times.

Design Criteria for Structural Steel and Pipe Support Evaluations

LC 3 – Dead load + Operating Thermal Loads + TSV Loads
Acceptance criteria: The allowable stresses shall be limited to 1.33 x Normal AISC Allowable stresses.

The following table summarizes the acceptance criteria for the load combinations listed above.

APPLICABLE TSV LOAD COMBINATIONS STRUCTURAL & AUXILIARY STEEL	**ACCEPTANCE CRITERIA**
DW + TH* + TR**	NORMAL 1.33 x AISC Allowable
DW + TH + $(SSE^2 + TR^2)^{1/2}$	FAULTED 1.60 x AISC Allowable < 0.95 x Fy***
EXPANSION ANCHOR BOLTS	
DW + TH + TR	SAFETY FACTOR = 4
DW + TH + $(SSE^2 + TR^2)^{1/2}$	SAFETY FACTOR = 2
PIPE SUPPORT COMPONENTS	
DW + TH + TR	ASME LEVEL C
DW + TH + $(SSE^2 + TR^2)^{1/2}$	ASME LEVEL D
PIPING	
DW + P + TR	ASME Level C
DW + P + $(SSE^2 + TR^2)^{1/2}$	ASME Level D

*TH = thermal loads

*TR = transient Loads such as TSV

*** Plastic section modulus can be used to determine the section stresses but must meet ductility criteria.

LC 4 – Dead Load + Operating Thermal Loads + SSE Loads + TSV Loads

Structural Steel Members Acceptance Criteria

Stress	Design Limit
Bending	1.6 x AISC allowable based on plastic section modulus with stresses not to exceed 0.95 x Fy. For this to be used, the section should satisfy the compact section criteria and lateral bracing requirements of the AISC Code. AISC LRFD Specification may be consulted to obtain further clarifications.
Axial	1.6 x AISC allowable not < 0.95 x Fy
Shear	$0.95 \times Fy / (3)^{1/2} = 0.548 \times Fy$

Plate Materials Acceptance Criteria

Stress	Design Limit
Bending about Weak Axis	0.95 x Fy based on plastic section modulus
Bending about Strong Axis	0.95 x Fy based on plastic section modulus or 1.0 x Fcr based on elastic section modulus, whichever is smaller.
Shear	0.95 x Fy / $(3)^{1/2}$ = 0.548 x Fy

Bolts Acceptance Criteria
1.60 x AISC Allowables.

Welds Acceptance Criteria
1.60 x AISC Allowables. The base metal shear for welds other than fillets shall not exceed 0.548 x Fy of the base metal. Base metal stress shall not govern for fillet welds.

Where the MS pipe supports combined loads as defined in combinations LC3 and LC4 do not exceed the original design basis loads (i.e., LC3 compared to operating basis earthquake (OBE) loads, and LC4 compared to SSE loads), the supporting structure was not reevaluated for the beyond design basis combinations.

The maximum stress ratios for each of the MS piping subsystems impacted by the TSV loads are provided in Table 13-1. The resultant pipe supports and drywell steel modifications are summarized in the response to Question 13B. With the modifications, the MS piping, pipe supports, and supporting drywell steel meet the above acceptance criteria. In addition, the current design and license basis criteria are met for the EPU conditions.

B. Table 13-2 identifies supports and piping systems that require modifications as a result of the extended power uprate.

Question
14. In Appendix G of the submittal, you indicated that restriction orifices to the stator water cooling system will be resized to accommodate the increased heat load. Additional cooling towers will be installed to ensure that the temperature of the water released to the environment remains within existing limits.

Confirm whether the proposed power uprate will increase the accident temperature, pressure and sub-compartment pressurization that affect the design basis analyses for steel and concrete in the containment, steam tunnel and the spent fuel pool. If the structural steel and concrete will *be affected, provide the design basis margin and margins after considering increased accident loading due to the proposed power uprate.*

Response
The EPU accident temperatures and pressures are bounded by the original structural design temperatures and pressures of the containment and containment sub-compartments, including the pressure suppression system and torus. Refer to PUSAR Sections 4.1.1, "Containment Pressure and Temperature Response," and 4.1.2, "Containment Dynamic Loads."

Temperatures and pressures due to feedwater and RWCU HELBs at EPU conditions increased slightly in some sub-compartments outside the containment, including the main steam tunnel (refer to PUSAR Table 10-1). The subcompartment structures were evaluated and are adequate as designed for the slightly increased pressures and temperatures.

Maximum Structural Margin Changes

Structure	**Interaction Ratio (IC)***	
	Pre-EPU	**EPU**
Concrete Sub-Compartments	0.946	0.995
Corner Room Structural Steel	0.62	0.83

* Maximum Allowable Interaction Ratio is 1.0.

The maximum EPU temperatures and pressures for the fuel pool structure and fuel racks are unchanged from the pre-EPU conditions (refer to PUSAR Table 6-2).

Table 9A-1 Large Bore Torus Water Piping Stress Results Dresden Unit 2

Piping Model	Description	Code	Pre-EPU Stress (psi)	[1]EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
D2.02	ECCS Ring Header	EQ. 10a, ASME Class II	37132	42126	45000	0.94
D2.03/D2.04	LPCI/CS Suction	102.3.2d, ANSI B31.1	33906	37007	37888	0.98
D2.08	LPCI Discharge	EQ. 10a, ASME Class II	33844	14700	45000	0.33
D2.05	HPCI Suction	EQ. 10a, ASME Class II	32241	32241	45000	0.72
D2.09.1	LPCI/CS Discharge	EQ. 10a, ASME Class II	25502	44159	45000	0.98
D2.09.2	CS Discharge	102.3.2c, ANSI B31.1	5384	7458	27000	0.28
D2.10	Vacuum Relief	EQ. 10a, ASME Class II	8049	9131	45000	0.20
D2.11	Pressure Suppression	EQ. 10a, ASME Class II	28247	28247	45000	0.63
D2.12	HPCI Turbine Exhaust	EQ. 10a, ASME Class II	13666	18931	45000	0.42
D2.13.1 (Internal)	LPCI Discharge	EQ. 10a, ASME Class II	29619	35435	45000	0.79
D2.13.1 (External)	LPCI Discharge	EQ. 10a, ASME Class II	25205	34916	45000	0.78
D2.13.2/D2.14.2	LPCI Discharge	EQ. 10a, ASME Class II	26010	42786	45000	0.95
D2.14.1 (Internal)	LPCI Discharge	EQ. 10a, ASME Class II	24283	29051	45000	0.65
D2.14.1 (External)	LPCI Discharge	EQ. 10a, ASME Class II	28969	40130	45000	0.89
D2-LPCI-09C	LPCI Discharge	102.3.2c, ANSI B31.1	23802	11601	27000	0.43
D2-LPCI-10C	LPCI Discharge	102.3.2c, ANSI B31.1	23871	11635	27000	0.43
D2-LPCI-12C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D2-LPCI-13C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D2-COSP-02B(C)	CS Discharge, Inside Drywell	102.3.2c, ANSI B31.1	7305	10119	27000	0.37
D2COSP-04C	CS Discharge	102.3.2d, ANSI B31.1	39173	32090	37500	0.86
D2-COSP-01B(C)	CS Discharge, Inside Drywell	102.3.2c, ANSI B31.1	15026	20815	27000	0.77

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(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) Thermal stress is considered negligible for the torus spray header since the spray Header and the torus expand uniformly.

Table 9A-2 Large Bore Torus Water Piping Stress Results Dresden Unit 3

Piping Model	Description	Code	Pre-EPU Stress (psi)	(1)EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
D3.02	ECCS Ring Header	EQ. 10a ASME CL II	30074	35979	45000	0.80
D3.03/D3.06	LPCI / CS Suction	EQ. 10a ASME CL II	30158	41600	45000	0.92
D3.04/D3.07	LPCI / CS Suction	EQ. 10a ASME CL II	27654	44308	45000	0.98
D3.08.1/08.3	LPCI Discharge	EQ. 10a ASME CL II	29299	34284	45000	0.76
D3.08.2	LPCI Discharge	EQ. 10a ASME CL II	7324	10146	45000	0.23
D3.05	HPCI Suction	EQ. 10a ASME CL II	10503	10503	45000	0.23
D3.09.1	LPCI/CS Discharge	EQ. 10a ASME CL II	18605	32216	45000	0.72
D3.09.2	CS Discharge	EQ. 10a ASME CL II	12080	16734	45000	0.37
D3.09.3	CS Discharge	EQ. 10a ASME CL II	8706	12060	45000	0.27
D3.10	Vacuum Relief	EQ. 10a ASME CL II	18021	24964	45000	0.55
D3.11	Pressure Suppression	EQ. 10a ASME CL II	25427	14001	45000	0.31
D3.12 (Internal)	HPCI Turbine Exhaust	EQ. 10a ASME CL II	19916	27589	45000	0.61
D3.12 (External)	HPCI Turbine Exhaust	EQ. 10a ASME CL II	19916	27589	45000	0.61
D3.13.1 (Internal)	LPCI Discharge	EQ. 10a ASME CL II	26648	31881	45000	0.71
D3.13.1 (External)	LPCI Discharge	EQ. 10a ASME CL II	24088	33368	45000	0.74
D3.13.3	LPCI Discharge	EQ. 10a ASME CL II	14055	18493	45000	0.41
D3.13.2/D3.14.2	LPCI Discharge	EQ. 10a ASME CL II	14079	23160	45000	0.51
D.3.14.1 (Internal)	LPCI Discharge	EQ. 10a ASME CL II	31549	37744	45000	0.84
D.3.14.1 (External)	LPCI Discharge	EQ. 10a ASME CL II	31359	43440	45000	0.96
D3.14.3	LPCI Discharge	EQ. 10a ASME CL II	20662	25828	45000	0.57
D3-LPCI-11C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D3-LPCI-12C (2)	Drywell Spray Header	102.3.2c, ANSI B31.1	0	0	27000	0.00
D3-COSP-RP01	CS Discharge, Inside Drywell	EQ. 12 ASME CL I	N/A	26156	60000	0.44
D3-COSP-RP02	CS Discharge, Inside Drywell	EQ. 12 ASME CL I	N/A	5020	52620	0.10
D3-RRCI-RP01	Recirc	EQ. 10a ASME CL II	27772	13053	45000	0.29
D3-RRCI-RP02	Recirc	EQ. 10a ASME CL II	15026	7062	45000	0.16

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(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) Thermal stress is considered negligible for the torus spray header since the spray header and the torus expand uniformly.

Table 9A-1QC Large Bore Torus Water Piping Stress Results Quad Cities Unit 1

Piping Model	Description	Code	Pre-EPU Stress (psi)	(1)EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
Q1.02	ECCS Ringheader	Eq 10a, ASME Class II	15301	16780	45000	0.37
Q1.03	RCIC Suction	Eq 10a, ASME Class II	22721	24917	45000	0.55
Q1.04	HPCI Suction	Eq 10a, ASME Class II	11953	16558	45000	0.37
Q1.05	RHR A/B Suction	Eq 10a, ASME Class II	50190	44660	52500	0.85
Q1.06	RHR C/D Suction	Eq 10a, ASME Class II	32627	35781	45000	0.80
Q1.07	Core Spray Suction	Eq 10a, ASME Class II	27998	30704	45000	0.68
Q1.08	Vacuum Relief	Eq 10a, ASME Class II	36037	43509	45000	0.97
Q1.09.1	RHR A/B Discharge	Eq 10a, ASME Class II	37168	40761	45000	0.91
Q1.09.2	RHR A/B Discharge	Eq 10a, ASME Class II	15316	18324	45000	0.41
Q1.09.3	RHR A/B Discharge	Eq 10a, ASME Class II	15316	18324	45000	0.41
Q1.10.1	CS Discharge	Eq 10a, ASME Class II	13727	15054	45000	0.33
Q1.10.2	CS Discharge	Eq 10a, ASME Class II	34021	37310	45000	0.83
Q1.11.1	RHR C/D Discharge	Eq 10a, ASME Class II	29089	31901	45000	0.71
Q1.11.2	RHR C/D Discharge	Eq 10a, ASME Class II	29300	35375	45000	0.79
Q1.11.3	RHR C/D Discharge	Eq 10a, ASME Class II	19350	20372	45000	0.45
Q1.13	HPCI Turbine Exhst	Eq 10a, ASME Class II	20253	22211	45000	0.49
Q1.14	RCIC Turbine Exhst	Eq 10a, ASME Class II	16244	22502	45000	0.50
Q1.15	Pressure Suppression	Eq 10a, ASME Class II	18288	10070	45000	0.22
Q1-RHRS-14B(C)	RHR Fuel Pool Cooling	102.3.2d, ANSI B31.1	21923	26228	27000	0.97
Q1-RHRS-09C	RHR Spray Header	102.3.2d, ANSI B31.1	16381	15796	27000	0.59
EMD-066699	RHR to Recirc	See Note 2				
Q1-COSP-01C	CS Disch Inside drywell	See Note 2				
Q1-COSP-02C	CS Disch Inside drywell	See Note 2				

(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) EPU condition does not control since analyzed at a temperature greater than 201.6 °F.

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Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 9A-2QC Large Bore Torus Water Piping Stress Results Quad Cities Unit 2

Piping Model	Description	Code	Pre-EPU Stress (psi)	(1)EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio
Q2.02	ECCS Ringheader	Eq 10a, ASME Class II	29687	32557	45000	0.72
Q2.03	RCIC Suction	Eq 10a, ASME Class II	8234	9030	45000	0.20
Q2.04	HPCI Suction	Eq 10a, ASME Class II	26154	28682	45000	0.64
Q2.05	RHR A/B Suction	Eq 10a, ASME Class II	18020	19762	45000	0.44
Q2.06	RHR C/D Suction	Eq 10a, ASME Class II	22705	24975	45000	0.56
Q2.07	Core Spray Suction	Eq 10a, ASME Class II	27808	38521	45000	0.86
Q2.08	Vacuum Relief	Eq 10a, ASME Class II	25128	30338	45000	0.67
Q2.09.1	RHR A/B Discharge	Eq 10a, ASME Class II	23098	37996	45000	0.84
Q2.09.2	RHR A/B Discharge	Eq 10a, ASME Class II	22752	27220	45000	0.60
Q2.09.3	RHR A/B Discharge	Eq 10a, ASME Class II	22752	27220	45000	0.60
Q2.10.1	CS Discharge	Eq 10a, ASME Class II	18442	20225	45000	0.45
Q2.10.2	CS Discharge	Eq 10a, ASME Class II	5975	6553	45000	0.15
Q2.10.3	CS Discharge	Eq 10a, ASME Class II	8300	9102	45000	0.20
Q2.11.1	RHR C/D Discharge	Eq 10a, ASME Class II	35941	39415	45000	0.88
Q2.11.2	RHR C/D Discharge	Eq 10a, ASME Class II	29749	35591	45000	0.79
Q2.11.3	RHR C/D Discharge	Eq 10a, ASME Class II	23230	24457	45000	0.54
Q2.13	HPCI Turbine Exhst	Eq 10a, ASME Class II	16819	23299	45000	0.52
Q2.14	RCIC Turbine Exhst	Eq 10a, ASME Class II	7500	10500	45000	0.23
Q2.15	Pressure Supp.	Eq 10a, ASME Class II	18168	10004	45000	0.22
Q2-RHRS-09B(C)	RHR Fuel Pool Cooling	102.3.2d, ANSI B31.1	13997	14855	27000	0.55
Q2-RHRS-09C	RHR Spray Header	See Note 2				
EMD-066794	RHR to Recirc	See Note 2				
EMD-067695	CS Disch inside drywell	102.3.2d, ANSI B31.1	19600	19600	26400	0.74

(1) Calculated Stress is for TE2 + THAM2 + TD4, where TE2 is thermal expansion, THAM2 is thermal anchor movements, and TD4 is torus displacement. All loads are based on the long term post-LOCA conditions associated with the EPU.

(2) EPU condition does not control since analyzed at a temperature greater than 201.6 °F.

Table 9A-3 Small Bore Torus Water Piping Stress Results Dresden Unit 2

Calculation Number	**System Identification*****	**Pre-EPU Stress (psi)**	**EPU Stress (psi)**	**Allowable Stress (psi)**	**Stress Ratio (EPU/Allowable)**
27.0200.2053.007	PS	20524	28431	45000	0.63
27.0200.2053.009	PS	24658	34158	45000	0.76
27.0200.2053.010	DAP	27712	38388	45000	0.85
27.0200.2053.013	PS	31280	43331	45000	0.96
27.0200.2053.014	PS	24243	33583	45000	0.75
27.0200.2053.015	PS	24243	33583	45000	0.75
27.0200.2053.016	PS	35205	19385	45000	0.43
27.0200.2053.028	N	35284	35284	45000	0.78
27.0200.2053.030	Core Spray	3514	4868	45000	0.11
27.0200.2053.040	Core Spray	16638	27370	45000	0.61
27.0200.2053.041	Core Spray	16527	27187	45000	0.60
27.0200.2053.043	LPCI	22329	30932	45000	0.69
27.0200.2053.051	LPCI	25552	35396	45000	0.79
27.0200.2053.059	LPCI	23592	38809	45000	0.86
27.0200.2053.061	LPCI	1651	5743	45000	0.13
27.0200.2053.062	LPCI	21879	35113	45000	0.78
27.0200.2053.063	LPCI	30095	30614	45000	0.68
27.0200.2053.074	LPCI	17934	36398	45000	0.81
27.0200.2053.077	LPCI	20924	33580	45000	0.75
27.0200.2053.078	LPCI	26073	41844	45000	0.93
27.0200.2053.079	LPCI	36901	34547	45000	0.77
27.0200.2053.089	HPCI	23780	41177	45000	0.92
27.0200.2053.090	HPCI	15108	24853	45000	0.55
27.0200.2053.102	CAM	38584	53449	56400	0.95
27.0200.2053.103	CAM	40117	55573	56400	0.99
27.0200.2053.104	ACAD	33094	43185	45000	0.96
27.0200.2053.105	ACAD	33118	44904	45000	1.00
D2-LPCI-02B(C)/Analysis	LPCI	34910	41853	45000	0.93

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
LPCI = Low Pressure Coolant Injection
HPCI = High Pressure Coolant Injection
CAM = Containment Atmosphere Monitoring
ACAD = Atmosphere Containment Atmosphere Dilution
N = Nitrogen Inerting and Drywell Oxygen Sampling

Table 9A-4 Small Bore Torus Water Piping Stress Results Dresden Unit 3

Calculation Number	System Identification***	Pre-EPU Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio (EPU/Allowable)
27.0200.2058.007	PS	30656	42467	45000	0.94
27.0200.2058.008	PS	27414	37976	45000	0.84
27.0200.2058.009	DAP	34792	48196	56400	0.85
27.0200.2058.013	PS	29963	36795	45000	0.82
27.0200.2058.014	PS	15562	20354	45000	0.45
27.0200.2058.015	PS	11961	12220	45000	0.27
27.0200.2058.016	PS	33689	18550	45000	0.41
27.0200.2058.049	Core Spray	29989	44889	45000	1.00
27.0200.2058.050	Core Spray	20314	35175	45000	0.78
27.0200.2058.051	LPCI	2047	2836	45000	0.06
27.0200.2058.052	LPCI	14702	20366	45000	0.45
27.0200.2058.061	LPCI	6963	9646	45000	0.21
27.0200.2058.062	LPCI	26056	36094	45000	0.80
27.0200.2058.075	LPCI	22376	38746	45000	0.86
27.0200.2058.089	LPCI	20364	35262	45000	0.78
27.0200.2058.095	LPCI	26166	41993	45000	0.93
27.0200.2058.113	HPCI	25906	37122	45000	0.82
27.0200.2058.114	HPCI	15108	24853	45000	0.55
27.0200.2058.120	CAM	28674	37884	56400	0.67
27.0200.2058.121	CAM	24308	32009	56400	0.57
27.0200.2058.122	ACAD	24684	32738	45000	0.73
27.0200.2058.123	ACAD	32547	43121	45000	0.96
D3-LPCI-02B(C)/Analysis	LPCI	11813	14766	45000	0.33

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
LPCI = Low Pressure Coolant Injection
HPCI = High Pressure Coolant Injection
CAM = Containment Atmosphere Monitoring
ACAD = Atmosphere Containment Atmosphere Dilution

Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 9A-3QC Small Bore Torus Water Piping Stress Results Quad Cities Unit 1

Calculation Number	System Identification***	Pre-EPU Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio (EPU/Allowable)
27.0200.1053.001	PS	15000	24675	45000	0.55
27.0200.1053.002	PS	19000	31255	45000	0.69
27.0200.1053.006	PS	26680	36959	45000	0.82
27.0200.1053.007	PS	14341	19866	45000	0.44
27.0200.1053.008	PS	25019	13776	45000	0.31
27.0200.1053.010	DAP	30454	42187	56400	0.75
27.0200.1053.011	PS	12658	17535	45000	0.39
27.0200.1053.012	PS	7524	10423	45000	0.23
27.0200.1053.019	Core Spray	24390	33787	45000	0.75
27.0200.1053.020	Core Spray	21771	30159	45000	0.67
QDC-1000-S-0456	RH	28749	31528	45000	0.70
27.0200.1053.043	RH	32295	42722	45000	0.95
27.0200.1053.047	RH	17654	24455	45000	0.54
27.0200.1053.059	HPCI	18205	25219	45000	0.56
Q1-HPCI-04B(C)	HPCI	13915	13915	45000	0.31
27.0200.1053.069	HPCI	15000	24675	45000	0.55
27.0200.1053.074	RCIC	7702	10669	45000	0.24
27.0200.1053.077	RCIC	41052	43639	45000	0.97
27.0200.1053.088	HPCI	15356	25261	45000	0.56
27,0200.1053.089	RCIC	16681	27440	45000	0.61
27.0200.1053.117	HPCI	28787	34756	45000	0.77

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
RH = Residual Heat Removal
HPCI = High Pressure Coolant Injection
RCIC = Reactor Core Isolation Cooling

Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 9A-4QC Small Bore Torus Water Piping Stress Results Quad Cities Unit 2

Calculation Number	System Identification***	Pre-EPU Stress (psi)	EPU Stress (psi)	Allowable Stress (psi)	Stress Ratio (EPU/Allowable)
27.0200.1058.001	Instrument Air	25501	35326	56400	0.63
27.0200.1058.004	PS	26400	36571	45000	0.81
27.0200.1058.005	PS	28612	39635	45000	0.88
27.0200.1058.010	PS	27903	38653	45000	0.86
27.0200.1058.011	PS	11118	15401	45000	0.34
27.0200.1058.012	PS	25116	34792	45000	0.77
27.0200.1058.013	DAP	15686	21729	49800	0.44
27.0200.1058.017	PS/NO	4798	5793	45000	0.13
27.0200.1058.018	PS	30072	36057	45000	0.80
27.0200.1058.032	RH	29342	32178	45000	0.72
27.0200.1058.051	RH	21361	29591	45000	0.66
Q2-RHRS-08B(C)	RH	29147	18179	45000	0.40
27.0200.1058.059	HPCI	29547	40930	45000	0.91
Q2-HPCI-02B(C)	HPCI	12372	12372	45000	0.27
27.0200.1058.066	HPCI	31514	43655	45000	0.97
27.0200.1058.079	HPCI	26405	36578	45000	0.81
27.0200.1058.080	HPCI	31675	43878	45000	0.98
27.0200.1058.081	HPCI	32352	44816	45000	1.00
27.0200.1058.085	RCIC	5077	7033	45000	0.16
27.0200.1058.095	RCIC	25965	37967	45000	0.84
27.0200.1058.096	CAM	44552	34060	56400	0.60
27.0200.1058.097	CAM	19787	27410	56400	0.49
27.0200.1058.102	HPCI	27228	37718	45000	0.84
27.0200.1058.103	Core Spray	13011	14269	45000	0.32
27.0200.1058.104	Core Spray	17922	19654	45000	0.44
QDC-1400-M-033	Core Spray	6640	3121	27000	0.12
Q2-RHRS-06B(C)	RH	36459	36459	45000	0.81
QDC-1000-M-185	RH	21800	21800	27000	0.81

*** PS = Pressure Suppression
DAP = Drywell Air Particulate Sampling
RH = Residual Heat Removal
HPCI = High Pressure Coolant Injection
RCIC = Reactor Core Isolation Cooling
CAM = Containment Atmosphere Monitoring
NO = Drywell Nitrogen and Oxygen Analyzer

Table 12A-1
Balance of Plant Piping System Evaluation Method and Results
DNPS Units 2 & 3

Piping System	Evaluation Method	Evaluation Results
Main Steam (outside RCPB)	See the response to Question 13A	See the response to Question 13A
Feedwater (outside RCPB)	Increases < 5%	Pass*
Reactor Recirculation	Increases < 5%	Pass
Control Rod Drive	Increases < 5%	Pass
RPV Bottom Head Drain	Increases < 5%	Pass
RPV Head Vent	Increases < 5%	Pass
Isolation Condenser	Increases < 5%	Pass
Shutdown Cooling	Increases < 5%	Pass
SRV Discharge	Increases < 5%	Pass
Reactor Water Clean Up	Increases < 5%	Pass
CCSW	Increases < 5%	Pass
Fuel Pool Cooling	Increases < 5%	Pass
Main Steam Drain Lines	Increases < 5%	Pass
Neutron Monitoring	Increases < 5%	Pass
MS Turbine By-Pass	Increases < 5%	Pass
Standby Liquid Control	Increases < 5%	Pass
Off Gas	Increases < 5%	Pass
Standby Gas	Increases < 5%	Pass
High Radiation Sampling	Increases < 5%	Pass
MS Cross Around Piping	Increases < 5%	Pass
Turbine Cross Around Piping	Increases < 5%	Pass
Condensate & Heater Drain	Increases < 5%	Pass

* FW flow increase factor 1.20, however system contains no fast acting valves and increase in flow is acceptable

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Table 12A-1
Balance of Plant Piping System Evaluation Method and Results
QCNPS Units 1 & 2

Piping System	Evaluation Method	Evaluation Results
Main Steam (outside RCPB)	See the response to Question 13A	See the response to Question 13A
Feedwater (outside RCPB)	Increases < 5%	Pass*
Reactor Recirculation	Increases < 5%	Pass
Control Rod Drive	Increases < 5%	Pass
RPV Bottom Head Drain	Increases < 5%	Pass
RPV Head Vent	Increases < 5%	Pass
RCIC	Increases < 5%	Pass
SRV Discharge	Increases < 5%	Pass
Reactor Water Clean Up	Increases < 5%	Pass
CCSW	Increases < 5%	Pass
Fuel Pool Cooling	Increases < 5%	Pass
Main Steam Drain Lines	Increases < 5%	Pass
Neutron Monitoring	Increases < 5%	Pass
MS Turbine By-Pass	Increases < 5%	Pass
Standby Liquid Control	Increases < 5%	Pass
Off Gas	Increases < 5%	Pass
Standby Gas	Increases < 5%	Pass
High Radiation Sampling	Increases < 5%	Pass
MS Cross Around Piping	Increases < 5%	Pass
Turbine Cross Around Piping	Increases < 5%	Pass
Condensate & Heater Drain	Increases < 5%	Pass

* FW flow increase factor 1.20, however system contains no fast acting valves and increase in flow is acceptable

Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

TABLE 13-1 DNPS

Unit	Subsystem	Code	Calculated Stress (psi)	Allowable Stress (psi)
DNPS Unit 2	MS Line A - RPV to drywell Pen	ASME Level C	24,991	27,000
		ASME Level D	26,766	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	22,532	27,000
		ASME Level D	33,247	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	14,256	27,000
		ASME Level D	25,368	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	22,633	27,000
		ASME Level D	33,504	36,000
DNPS Unit 3	MS Line A - RPV to drywell Pen	ASME Level C	23,487	27,000
		ASME Level D	35,260	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	21,856	27,000
		ASME Level D	34,102	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	17,864	27,000
		ASME Level D	29,610	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	23,607	27,000
		ASME Level D	33,385	36,000
DNPS Unit 2	MS Lines A, B, C & D Outside Drywell	ASME Level C	14,972	27,000
		ASME Level D	13,989	36,000
DNPS Unit 3	MS Lines A, B, C & D Outside Drywell	ASME Level C	14,972	27,000
		ASME Level D	13,989	36,000

ASME Level C = DW + PR +TSV
ASME Level D = DW + PR + SRSS(SSE + TSV)

DW = deadload stress (psi)
PR = pressure stress (psi)
TSV = turbine stop valve stress (psi)
SSE = safe shutdown earthquake stress (psi)

TABLE 13-1 QCNPS

Unit	Subsystem	Code	Calculated Stress (psi)	Allowable Stress (psi)
Quad Cities Unit 1	MS Line A - RPV to drywell Pen	ASME Level C	24,119	27,000
		ASME Level D	33,922	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	20,139	27,000
		ASME Level D	33,733	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	26,025	27,000
		ASME Level D	35,770	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	21,000	27,000
		ASME Level D	35,306	36,000
Quad Cities Unit 2	MS Line A - RPV to drywell Pen	ASME Level C	25,291	27,000
		ASME Level D	35,336	36,000
	MS Line B - RPV to drywell Pen	ASME Level C	26,638	27,000
		ASME Level D	34,459	36,000
	MS Line C - RPV to drywell Pen	ASME Level C	22,441	27,000
		ASME Level D	34,546	36,000
	MS Line D - RPV to drywell Pen	ASME Level C	16,484	27,000
		ASME Level D	29,127	36,000
QCNPS Unit 1	MS Lines A, B, C & D Outside Drywell	ASME Level C	21,673	27,000
		ASME Level D	27,260	36,000
QCNPS Unit 2	MS Lines A, B, C & D Outside Drywell	ASME Level C	21,673	27,000
		ASME Level D	27,260	36,000

ASME Level C = DW + PR +TSV
ASME Level D = DW + PR + SRSS(SSE + TSV)

DW = deadload stress (psi)
PR = pressure stress (psi)
TSV = turbine stop valve stress (psi)
SSE = safe shutdown earthquake stress (psi)

Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Table 13-2 DNPS

SUPPORT NUMBER	MODIFICATION DESCRIPTION
DNPS Unit 2 - TAP SUPPORT MODIFICATIONS	
SUPPORT NUMBER	MODIFICATION DESCRIPTION
2-15-M321315	Change spring hanger loads
2-15-M321423	Revise baseplate mounting
2-15-M3381	Revise U-Bolt
2-14-M320924	Revise baseplate design and add new brace
2-14-M320808	Replace rigid strut with snubber
DNPS Unit 2 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
2-3001A-49	Replace snubber assembly and add stiffener angle and welds
2-02-2870SH1 2-02-2870SH2	Add two box frame supports at MS bypass loop in Turbine Building
2-02-2870SH3 2-02-2870SH4	Add lateral guides inside 2 G-line wall sleeves
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates
2-3001-H86 2-3001-H89	Remove existing pipe supports
DNPS Unit 3 - TAP SUPPORT MODIFICATIONS	
3-14-M340919	Increase the size of existing welds on support cleats
3-14-M340921	Install additional stiffener plates and associated welds
3-15-M340819	Add additional welds to existing support
3-15-M340827	Install additional stiffener plates and add additional welds to existing support
3-15-M340906	Add new brace with associated baseplate and anchor bolts
DNPS Unit 3 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
3-3001A-S2	Add new welds and stiffener plates to existing members
3-3001C-S2	Add new support member and welds and reduce length of snubber extension piece
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates
3-02-3870SH1 3-02-3870SH2	Add two box frame supports at MS bypass loop in Turbine Building
3-02-3870SH3 3-02-3870SH4	Add lateral guides inside 2 G-line wall sleeves
3-02-M778ASH26 3-02-M778ASH27	Add new supports for rerouting of MS drain line
3-3001-H86 3-3001-H89	Remove existing pipe supports

Table 13-2 QCNPS

SUPPORT NUMBER	MODIFICATION DESCRIPTION
QCNPS Unit 1 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
1-3001B-20-S1	Replace snubber assembly, replace support structure by tube steel members
1-3001B-20-S2	Relocate pipe clamp to accommodate new clamp for 1-3001B-20-S1
1-3001C-S2	Add new welds, replace a snubber
1-3001D-R1	Add new welds, replace support member
1-3001-988D-8-1 1-3001-988D-8-2 1-3001-988D-8-3 1-3001-988D-8-4	Add special LISEGA Clamps and horizontal and vertical struts to main steam lines
1-3059-988D-8-5 1-3059-988D-8-6	Add new supports for rerouting of MS equalizing line
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates
QCNPS Unit 2 - TAP SUPPORT MODIFICATIONS	
2-1810-07	Reset spring can displacements
2-1810-35	Add stiffener plate
QCNPS Unit 2 - MS PIPE SUPPORT AND DRYWELL STEEL MODIFICATIONS	
2-3001A-R4	Add stiffeners to existing steel beam
2-3001B-S2	Add new welds, strengthening structural beam
2-3001B-R1	Replace existing strut
2-3001C-R1	Replace existing strut
2-3001C-S2	Replace entire support structure by tube steel members and add stiffeners to steel beam
2-3001-1020D-6-1 2-3001-1020D-6-2 2-3001-1020D-6-3 2-3001-1020D-6-4	Add special LISEGA Clamps and horizontal and vertical struts to main steam lines
DRYWELL STEEL	Strengthen various beam end connections using packing, bumper and stiffener plates, replace bolting at 5 connections (EL. 593)

Attachment C
Additional Mechanical Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References:

1. Licensing Topical Report, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32424P-A, Class III, February 1999

2. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

3. Letter from U. S. NRC to O. D. Kingsley (Exelon Generation Company, LLC), "Issuance of Amendments; Increase in Reactor Power, Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2," dated May 4, 2001

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RS-01-151

August 7, 2001

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Dresden Nuclear Power Station, Units 2 and 3
Facility Operating License Nos. DPR-19 and DPR-25
NRC Docket Nos. 50-237 and 50-249

Quad Cities Nuclear Power Station, Units 1 and 2
Facility Operating License Nos. DPR-29 and DPR-30
NRC Docket Nos. 50-254 and 50-265

Subject: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

References Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

In the referenced letter, Commonwealth Edison (ComEd) Company, now Exelon Generation Company (EGC), LLC, submitted a request for changes to the operating licenses and Technical Specifications (TS) for Dresden Nuclear Power Station, Units 2 and 3, and Quad Cities Nuclear Power Station, Units 1 and 2, to allow operation at uprated power levels. In a telephone conference call between representatives of EGC and Mr. L. W. Rossbach and other members of the NRC staff, the NRC requested additional information regarding these proposed changes. Attachments A and B to this letter provide a portion of the requested information. The remainder of the requested information will be provided in a separate letter.

Some of the information in Attachment A is proprietary information to the General Electric Company, and EGC requests that it be withheld from public disclosure in accordance with 10 CFR 2.790(a)(4), "Public Inspections, Exemptions, Requests for Withholding." This information is indicated with sidebars. Attachment C provides the affidavit supporting the request for withholding the proprietary information in Attachment A from public disclosure, as required by 10 CFR 2.790(b)(1). Attachment D contains a non-proprietary version of Attachment A.

Should you have any questions related to this letter, please contact Mr. Allan R. Haeger at (630) 657-2807.

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Respectfully,

Terrence W. Simpkin

for K. A. Ainger
Director – Licensing
Mid-West Regional Operating Group

Attachments:

Affidavit
Attachment A: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (proprietary version)
Attachment B: Draft Revision to Updated Final Safety Analysis Report Section 6.2.1.3
Attachment C: Affidavit for Withholding Portions of Attachment A from Public Disclosure
Attachment D: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station, Units 2 and 3, Quad Cities Nuclear Power Station, Units 1 and 2 (non-proprietary version)

cc:
Regional Administrator – NRC Region III
NRC Senior Resident Inspector – Dresden Nuclear Power Station
NRC Senior Resident Inspector – Quad Cities Nuclear Power Station
Office of Nuclear Facility Safety – Illinois Department of Nuclear Safety

bcc: Dresden Unit 2/3 Project Manager - NRR
Quad Cities Project Manager - NRR
Manager of Energy Practice - Winston & Strawn
Director – Licensing, Mid-West Regional Operating Group
Manager – Licensing, Dresden and Quad Cities Station
Site Vice President – Dresden Station
Site Vice President – Quad Cities Station
Regulatory Assurance Manager – Dresden Station
Regulatory Assurance Manager – Quad Cities Station
W. Leech – MidAmerican Energy Company
D. Tubbs – MidAmerican Energy Company
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STATE OF ILLINOIS)

COUNTY OF DUPAGE)

IN THE MATTER OF)

EXELON GENERATION COMPANY, LLC) **Docket Numbers**

DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3) **50-237 AND 50-249**

QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2) **50-254 AND 50-265**

SUBJECT: Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station

AFFIDAVIT

I affirm that the content of this transmittal is true and correct to the best of my knowledge, information and belief.

J. A. Benjamin
Vice President – Licensing and Regulatory Affairs

Subscribed and sworn to before me, a Notary Public in and

for the State above named, this 7th day of

August, 2001.

V. Lynn Bernhagen
Notary Public

"OFFICIAL SEAL"
V. LYNN BERNHAGEN
Notary Public, State of Illinois
My Commission Exp. 05/30/2004

Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

This attachment contains responses to NRC Questions 1 through 8, 12, 15, and 17 through 30. Responses to NRC Questions 9, 10, 11, 13, 14, and 16 will be provided separately.

Question
1. *During a telephone call on April 30, 2001, your staff noted that changes were being planned in the feedwater and condensate systems to improve the trip avoidance capability of the plant from transients initiated in these systems at the extended power uprate (EPU) full power conditions. These changes were not described in your application. For both Dresden and Quad Cities, describe the various existing features and planned changes (e.g., delayed tripping of a main feedwater pump on low suction pressure; reactor recirculation pump runbacks) which will minimize plant trips from these conditions. Describe plant startup testing and/or post modification testing which will examine these modifications.*

Response
The EPU feedwater and condensate modifications being implemented to avoid spurious reactor scrams are the addition of a reactor recirculation pump runback feature, changes to the reactor feedwater pump low suction pressure trip logic, and changes to the scaling of feedwater control and indication loops.

Reactor Recirculation Pump Runback
A reactor recirculation pump runback is being added as a trip avoidance feature to reduce the potential for a reactor low water level scram on the loss of either a feedwater or condensate pump at extended power uprate (EPU) conditions. In addition, the reactor low water level scram and isolation setpoint is being changed as discussed in Reference 1, Attachment E, "Power Uprate Safety Analysis Report," (PUSAR), Section 5.3.8. A dynamic analysis of a single feedwater pump trip at EPU conditions indicates that an automatic reactor recirculation runback can reduce core flow and thermal power to within the capability of the running feedwater pumps and avoid a reduction in reactor water level to the scram setpoint. The runback on loss of a condensate pump is initiated in anticipation of the reduced feedwater pump suction pressure when only three of the four condensate pumps remain in operation.

The runback logic is enabled when reactor power exceeds the capability of two feedwater pumps, as measured by total steam flow. A runback is initiated when less than three feedwater pumps are running and reactor water level drops below the low level alarm setpoint, or when less than four condensate pumps are running and total feedwater flow exceeds the capacity of two feedwater pumps. The runback will rapidly reduce core flow to approximately 70% of rated core flow, which is equivalent to 82% of uprated thermal power on the highest rod line. This feature will not alter the response characteristics of the reactor recirculation speed control system under normal operating conditions.

Proper operation of the runback logic will be verified in a post modification functional test. The feedwater control system response will be verified at various power levels. These tests will be used to confirm the runback dynamic analysis.

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Reactor Feedwater Pump Low Suction Pressure Trip Logic
Since EPU conditions require the operation of three feedwater and four condensate pumps, there is an increased potential for low feedwater pump suction pressure in the event of a condensate pump trip. Both stations currently have feedwater pump protection logic for low suction pressure conditions. For EPU, this logic will be modified to stagger the feedwater pump trips consistent with three pump operation. The revised logic will trip one feedwater pump if suction pressure decreases to the low suction pressure trip setpoint for 3 to 5 seconds, then trip a second pump if suction pressure remains below this setpoint for 12 to 15 seconds. The remaining feedwater pump will not trip until suction pressure decreases to the low-low suction pressure trip setpoint. All pumps will continue to trip immediately if suction pressure decreases below the low-low suction pressure trip setpoint. Proper operation of the feedwater pump low suction pressure trip logic will be verified in a post modification functional test.

Scaling of Feedwater Control and Indication Loops
To accommodate the increased flow rates, the scaling of steam and feedwater flow loops will be increased to 3.5 million pounds mass per hour (Mlb/hr) for each steam line, 7 Mlb/hr for each feedwater pump, and 14 Mlb/hr each for total steam and feedwater flow. The feedwater pump runout (i.e., maximum feedwater flow) logic will also be revised to accommodate three pump operation. In addition to normal loop calibration and functional testing, the dynamic response of the control system will be verified by incremental step changes at various power levels. Feedwater flow indication will be verified at 90 % and 100 % rated thermal power (RTP) using installed ultrasonic flow devices. Feedwater pump performance will be monitored at various power levels to confirm runout protection requirements. Steam flow will be verified against feewater flow.

Question
2. Provide additional discussion of the effect of the EPU on the feedwater system, including your plans for handling additional flow in the system including heater drains. Are the line and valve sizing and system characteristics adequate for EPU conditions or are changes required? The regulatory concern is challenges to operators and safety systems caused by loss of feedwater heater strings and challenges to fuel integrity caused by the transients associated with loss of feedwater heating.

Response
The results of the EPU performance assessments of the balance of plant main thermal-hydraulic power cycle systems (i.e., feedwater, condensate, and heater drain valves), including consideration of the effect of the actual material conditions, indicate that the design capacity of these systems is sufficient to permit operation at EPU conditions. The thermal-hydraulic power cycle systems do not present a significant risk of additional feedwater transients as a result of EPU.

Evaluation of the feedwater heater drain system piping, valves, and instruments was performed at the pressures and temperatures expected at EPU conditions, assuming the turbine control valves were fully open. Reviews of the feedwater heater level control valve (LCV) and drain valve flows required for a range of uprated power levels were performed and compared to their flow passing capabilities. These reviews determined that the EPU operating conditions do not significantly challenge the inherent flow passing capabilities of the LCVs, with the exception of the DNPS Units 2 and 3 feedwater heater "B" normal LCVs. Further evaluations confirmed that trim replacement for these DNPS LCVs is required. These trim replacements will be implemented during each of the DNPS EPU refueling outages. QCNPS previously made similar changes to these valves and thus does not require this modification. Therefore, the system design will be adequate to prevent additional loss of feedwater transients.

The feedwater heater vessels were evaluated at EPU flows, pressures, and temperatures. With the planned shell modifications to re-rate the "C" and "D" feedwater heaters for increased pressures described in the Attachment G of the PUSAR, these vessels will be adequate to support operation at EPU conditions.

Therefore, based upon the above evaluations, additional challenges to operators, safety systems, and fuel integrity are not expected as a result of operation at EPU conditions.

Question
3. State the re-rated conditions for the feedwater heaters.

Response
The re-rated conditions for the feedwater heaters are provided in Figure 1.

Question
4. With the proposed modifications to the steam dryers, will the moisture carryover remain within the original design bases following EPU? If not, what reviews have been conducted to evaluate the increased moisture carryover?

Response
Review and analysis of current moisture carryover data, and the potential impact of EPU on moisture carryover, determined the need for a modification to the present steam dryer assemblies. The design criteria for the modification was to maintain carryover $\leq$ 0.2 wt% under most normal operating conditions, which is equivalent to the original startup test acceptance criteria. This design criteria was established based upon actual moisture carryover data collected from both the Dresden and Quad Cities Stations. Physical testing of the modified steam dryer assemblies confirmed the carryover fraction to be consistent with the modification design criteria.

Question
5. You have requested a significant increase in the magnitude of a main steam line break that will not be isolable automatically by the main steam isolation signal. You requested to raise the main steam isolation flow from 120% pre-EPU to 125% post-EPU for Dresden Unit 2; 120% pre-EPU to 140% post-EPU for Dresden Unit 3; and 138% pre-EPU to 254.3 psid for Quad Cities. The stated basis in NEDC-32424P-A for the increased magnitude of a main steam line break is to keep the same basis (expressed as a percentage of steam flow) to assure that reactor trip avoidance is maintained. For Dresden and Quad Cities, with a 17% power uprate, this

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corresponds to an increase of 20% flow if the same percentage of steam line flow were maintained as addressed in the topical report.

What analyses have been performed for the safety impact (e.g., on core damage frequency or on high energy line break (HELB) analyses) of this additional range of steam line breaks (beyond the increase addressed in the EPU topical report), that is no longer automatically isolable? Provide the basis for the additional requested steam line break flow.

Response
The ELTR (Reference 2), Section F.4.2.5, "MSIV Closure on High Steam Flow Setpoint," states, "The setpoint for initiation of MSIV closure on high steam flow shall be raised to be equivalent to $\leq$ 140% of the uprated steam flow in each steamline." The proposed DNPS and QCNPS setpoints are all within the topical report setpoint.

The HELB analyses performed for EPU for main steam line breaks identified no additional impact due to EPU. The bounding steam line break is a complete rupture that results in choked flow through the flow restrictor. Since system pressure is not changed under EPU conditions, mass releases from such breaks are the same as before EPU. Since the mass releases are unchanged, there is no additional impact on the reactor core or on structures, systems, or components due to EPU.

For main steam line breaks resulting in less flow than the high flow setpoint, two diverse isolation signals will isolate postulated breaks. In RUN mode, low steam line pressure will result in isolation for breaks large enough to depressurize the steam line. Breaks that pass from 120%-140% flow will result in the low pressure isolation signal. These breaks are therefore still automatically isolable following EPU, regardless of location. In addition, postulated breaks in the main steam tunnel would actuate the area high temperature switches and result in isolation. Operability of both of these isolation signals is governed by the DNPS and QCNPS Technical Specifications (TS).

Question
6. Provide short term and long term results (curves or tables of calculated values as a function of time) of calculations for

- *drywell short term pressure and temperature*
- *suppression pool short term temperature*
- *wetwell atmosphere short term pressure and temperature*
- *suppression pool long term temperature*
- *wetwell atmosphere long term pressure and temperature*

If the long term calculation results are different from those used for calculating NPSH, provide the suppression pool long term temperature and wetwell atmosphere long term pressure and temperature used for the NPSH calculation.

Response
Drywell short term pressure and temperature are provided in Figures 2 and 3. Suppression pool short term temperature is provided in Figure 3. Wetwell atmosphere short term pressure and temperature are provided in Figures 2 and 3. Suppression pool long term temperature is provided in Figures 5 and 9. Wetwell atmosphere long term pressure and temperature are provided in Figures 4,5,8, and 9. Notes for the figures are provided in Table 1.

Figures 6,7,10, and 11 provide the curves showing the wetwell atmosphere pressure and temperature and the suppression pool temperature used for the net positive suction head (NPSH) calculation. As noted in Table 1, appropriate assumptions were used to minimize the containment pressure available and maximize the required NPSH.

Question
7. For Quad Cities, provide additional detail of the confirmatory calculations validating the SHEX computer code (ELTR1 SER Section 2.6(a)).

Response
Case E of the QCNPS UFSAR Table 6.2-3 was selected as a benchmark case to validate the SHEX computer code. This benchmark case was analyzed with SHEX, using input assumptions, which best represent the case. Case E assumed an instantaneous double-ended break of a reactor recirculation suction line (DBA-LOCA). It was assumed that one RHR loop equipped with one RHR pump and one service water pump is available. The input assumptions used in the benchmark analysis were not necessarily the same as those used for the EPU analysis. For instance, feedwater addition, which would result in higher peak pool temperature, was included in the EPU analysis, whereas the benchmark analysis ignored its effect. The following table provides key input assumptions used in the benchmark analysis.

Parameter	Value	Remarks
Decay heat	May-Witt	In the Long Term Program (LTP) for Mark I containment, the May-Witt decay heat values were used. It was assumed that the same decay heat values had been used around 1969 in the absence of information on the decay heat values used in the UFSAR analysis.
Feedwater addition	None	It is believed that feedwater addition was ignored in the original UFSAR analysis, since there is no mention about that in the UFSAR. Feedwater addition would result in a higher peak pool temperature.
Initial pool temperature	90°F	Based on plots.
RHR heat	276.1	The K-value is defined as total heat removal

Parameter	Value	Remarks
exchanger K-value	Btu/sec-°F	rate (Btu/sec) divided by the heat exchanger inlet temperature difference. The K-value was obtained from process diagram.
Service water temperature	95°F	Obtained from process diagram. For typical analyses, the service water temperature is assumed to be the same as or lower than pool temperature.

Thus, the benchmark case (Case E of UFSAR Table 6.2-3) was analyzed with SHEX, and the peak pool temperature from the SHEX run was 181°F, which is 4°F higher than the 177°F reported in the UFSAR. This benchmark calculation, though based on limited information on the UFSAR analysis assumptions, shows that the SHEX prediction is representative, compared with the UFSAR analysis.

Question

8. Dresden proposed Technical Specification bases section B 3.6.1.4 is changed to reflect a reduced calculated peak drywell pressure of 43.9 psig for the limiting event. Additionally, the listed reference is changed to Updated Final Safety Analysis Report (UFSAR) Section 6.2.1.3, which was not provided in the application. Provide the referenced UFSAR Section or a draft of the section if it has not been revised for the EPU uprate.

Response

The proposed UFSAR Section 6.2.1.3, "Design Evaluation," is currently in draft form and is provided as Attachment B for both DNPS and QCNPS, for information only.

Question

12. Section 4.7 on post-LOCA combustible gas control notes margin changes in various parameters associated with the EPU and additional impact of GE14 fuel introduction on metal-water hydrogen production. Provide long term results (curves or tables of calculated values as a function of time) of calculations for

- *hydrogen and oxygen production*
- *hydrogen and oxygen concentrations*
- *nitrogen containment atmosphere dilution system nitrogen cumulative usage and capacity*
- *containment pressure buildup demonstrating meeting the 30-day acceptance limit.*

Response

Hydrogen production is provided in Figure 12. Oxygen production is not specifically presented, but equals one half of the hydrogen production.

Hydrogen and oxygen concentrations in primary containment without the use of the nitrogen containment atmosphere dilution (NCAD) system are provided in Figure 13.

Hydrogen and oxygen concentrations with the use of the NCAD system are provided in Figure 14.

NCAD system nitrogen cumulative usage is provided in Figure 15. The NCAD nitrogen storage system has a minimum volume of 200,000 scf as discussed in PUSAR Section 4.7, "Post-LOCA Combustible Gas Control."

Containment pressure buildup demonstrating meeting the 30-day acceptance limit of 50% of design pressure is provided in Figure 16.

Question

15. What effect, if any, does the EPU have on the service water system heat loads for the HPCI and LPCI room coolers?

Response

DNPS ECCS room cooler equipment consists of coolers for the LPCI/CS rooms and the HPCI room. QCNPS ECCS room cooler equipment consists of coolers for the RHR rooms and the HPCI room.

Under normal operating conditions, EPU has no effect on HPCI and LPCI room coolers.

After a design basis LOCA, the EPU suppression pool temperature will be higher than the pre-EPU pool temperature. Thus, EPU affects the RHR and LPCI/CS pump rooms since the pumps and the heat exchangers in these rooms process the higher temperature water from the suppression pool during emergency operation. This will increase the piping and heat exchanger heat loads to the rooms. The electrical heat load in ECCS rooms is not affected by EPU.

The QCNPS RHR corner room service water heat load will increase from 319,798 BTU/hr to 335,800 BTU/hr due to the higher EPU suppression pool temperature. The RHR corner room cooler capacity is 570,000 BTU/hr, which is greater than the EPU heat load. Therefore, the design LOCA room temperature of 150°F is not affected by EPU.

The DNPS LPCI/CS room service water heat load also increases due to EPU. However, no credit is given to the DNPS LPCI/CS corner room coolers for removal of the heat load. Under EPU post accident conditions, the peak room temperature is conservatively calculated to be 189° F without the use of the room coolers. The safety related components in these rooms have either been environmentally qualified to the higher temperatures or are being replaced with instruments that are environmentally qualified to the higher EPU post accident temperatures.

HPCI operation involving the suppression pool is not changed by EPU. Following a design basis LOCA, the reactor quickly depressurizes below the limit for HPCI operation. Therefore, HPCI is not credited and its components are not required to be environmentally qualified to the higher room temperatures resulting from a design basis LOCA.

HPCI room coolers are utilized to maintain the HPCI rooms as a mild environment during testing and for operation of the HPCI system during a small break LOCA. The maximum HPCI process temperature is unchanged for EPU, and is accommodated by the existing room coolers.

Question

17. Section 6.4.5 addresses the adequacy of the ultimate heat sink (UHS). In the event of downstream dam losses, the water trapped in the intake and discharge bay becomes the UHS for Quad Cities 1&2 and the water trapped in the intake canal becomes the UHS for Dresden 2&3. Considering the increased decay heat associated with the EPU, provide details of the analyses of the available water supply trapped in these UHSs for safe shutdown for all units; addressing conformance with Regulatory Guide 1.27. Include any revised timing of required operator actions to maintain the UHS; if any.

Response

The design basis for the DNPS and QCNPS Cities UHS was established prior to the issuance of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants." The design bases for the DNPS and QCNPS UHS are provided in UFSAR Section 9.2.5, "Ultimate Heat Sink," for each plant.

The capability of the UHS for operation at EPU conditions was evaluated within the context of the UHS design bases as stated above. The results are provided as follows.

QCNPS UHS Evaluation

At EPU conditions, with the use of the main condenser for 24 hours after shutdown, and the use of three portable pumps delivering 5100 gpm to the Residual Heat Exchanger Service Water (RHRSW) intake, the water in the suppression pool remains below the acceptance value of 177° F. The temperatures reached are 156° F prior to EPU and 166° F for EPU. The maximum cribhouse intake temperature remains below the acceptance value of 109° F. The temperatures reached are 106.5° F prior to EPU and 108° F for EPU for operation of one RHR pump and one RHRSW pump per unit.

Manual actions for placing and operating the portable diesel pumps in the event of a postulated failure of Lock and Dam No. 14 do not change as a result of EPU. The time available to position and operate the portable pumps to provide the makeup water from the river to the UHS is dependent only on the time to reach separation between the UHS and river (i.e., approximately two days) and is not affected by EPU operation.

DNPS UHS Evaluation

The response for the DNPS UHS evaluation will be provided separately.

Question

18. Section 7.1 Considering reactor power may now be limited by main generator capability, discuss implications of potentially load cycling the reactor due to environmental changes – such as diurnal heating and cooling effects changing cycle efficiency. Will this mode result in additional radioactive wastes being generated?

Response

The main generator will be limited to 912 megawatts-electric (MWe). Because of this limitation, and the change in plant efficiency over the course of an operating cycle, the thermal power of the reactor will generally be less than the rated thermal power of 2957 megawatts-thermal (MWth). It is expected that to maintain 912 Mwe during the coldest winter days, the reactor thermal power would be on the order of 2850 Mwth (i.e., approximately 96% of EPU RTP), while on the warmest summer days the reactor power would be expected to be near 2957 MWth (100% of EPU RTP). This 4% yearly variation in reactor power is easily achieved via a combination of changes in the operating control rod pattern and reactor core flow. These changes are very small over the time interval in which they occur. On a daily basis these changes due to plant efficiency parameters do not approach the magnitude of reactor power changes required for surveillance testing and rod pattern adjustments.

Radioactive waste generated is primarily affected by an increase in conductivity and increase in the amount of feedwater flow as a result of operating at higher power level. The effect on the generation of radioactive wastes due to load following is negligible. The conductivity and feedwater flow and the radioactive waste generated will not increase beyond that determined for the operation of the reactors at the maximum EPU power level for an entire operating cycle.

Question

19. PUSAR Section 4.1.1.1.(b), Local Pool Temperature with RV plus SRV Discharge, notes that because these plants have quenchers no evaluation nor limit is necessary as long as steam ingestion into the ECCS suction is not a concern. The NRC approved elimination of the local temperature limit provided quenchers were at an elevation above the ECCS suction. Since Dresden and Quad Cities have quenchers and suction strainers located in the same bays; an evaluation of the behavior of the steam plumes from the quenchers, relative to the entrainment flow path to the ECCS strainers was performed. Provide the details of this evaluation demonstrating that steam ingestion is not a concern. Include a description of the units' ECCS suction elevation relative to the suction strainers.

Response

The NRC previously approved elimination of the local pool temperature limit at DNPS as noted in Reference 4. As part of EPU, it was decided to include elimination of the local pool temperature limit for QCNPS as well.

An evaluation of the likelihood of steam ingestion into the ECCS suction strainers during safety relief valve (SRV) actuation was performed for DNPS and QCNPS. The evaluation was performed at EPU conditions for the most limiting geometry from the two plant designs, which was a case where the suction strainer and t-quencher are in the same torus bay with the least physical separation. The evaluation used the conservative assumption that the suppression pool is locally saturated in the region around the SRV quenchers and ECCS suction strainers. The evaluation also conservatively assumed operation of all ECCS pumps simultaneously with full SRV discharge flow.

The conservative premise was that steam ingestion would be predicted if the quencher steam plume intersects any part of the ECCS suction strainer or the entrainment envelope surrounding the suction strainer. The size of the steam plume generated from an SRV quencher and the envelope of flow drawn into the suction strainers were quantified and evaluated for overlap, which could result in steam ingestion. The results of these evaluations show that the steam plume from the SRV quencher located closest to a suction strainer will not intersect either the suction strainer or the envelope of flow (i.e., the entrainment envelope) drawn into the strainer. Therefore, steam ingestion is not predicted.

Since steam ingestion is not predicted at EPU conditions for the most limiting geometry, it is concluded that steam ingestion will not occur at DNPS or QCNES.

The ECCS pump suctions are located approximately six feet below the torus penetration connecting the ECCS ring header to the suction strainers (centerline to centerline). The strainer itself extends approximately five feet vertically into the torus from the penetration.

Question
20. Section 7.1 Provide the results of the evaluation of low pressure turbine missile analyses. Did these reanalyses confirm the potential need to change turbine overspeed protection settings?

Response
A missile analysis was previously performed for the DNPS and QCNPS turbines in 1986. Based upon review of this missile analysis, the predominant stresses that could cause a LP rotor failure were attributed to the centrifugal loading with only a small thermal stress contribution. Since the geometry of the LP rotors and blading is not changing as a result of EPU, the centrifugal stresses also do not change, and the existing analysis remains valid.

The overspeed to limit of 120% of rated speed is the limit used during original design and is not changing for EPU. Because EPU increases steam flow, turbine overspeed protection settings were reviewed by the original equipment manufacturer (OEM). As a result of this review, the current trip settings will be reduced, as applicable, to preclude rotor train speeds in excess of 120% of rated speed in the unlikely event of a simultaneous full load rejection and failure of both control and intermediate valves. A change to the backup overspeed trip (BUOT) setpoint in accordance with the OEM's recommendation is required at QCNPS Units 1 and 2. The current DNPS BUOT setpoint is within the range of the OEM recommendations and does not require revision.

Question
21. Section 7.1 notes that for the turbine-generator; valves, control systems and other support systems were evaluated for the effects of EPU. The results of the evaluation show that modifications to the high pressure turbine and some non-safety-related equipment should ensure satisfactory turbine-generator performance. Describe these modifications.

Response

Station	Modification Description
DNPS Units 2 and 3 QCNPS Units 1 and 2	Cross around relief valve (CARV) setpoint change – provide new relief pressure settings for all CARVs
DNPS Units 2 and 3 QCNPS Units 1 and 2	Replacement of HP turbine rotors and diaphragms – new HP boreless rotor and HP nozzle diaphragms for increased volumetric flows
DNPS Units 2 and 3 QCNPS Units 1 and 2	Stator water cooling alarm and runback setpoint changes - adjusted for revised flow conditions
DNPS Units 2 and 3 QCNPS Units 1 and 2	Electrohydraulic control / turbine supervisory instrumentation changes • Steam line resonance compensator – addition of 3rd harmonic filter • Diode function generator calibration – adjustment of control valve characteristic with increased steam flow • Turbine 1st stage pressure transmitter change – adjustment for new rated condition • Power load unbalance input span changes – adjustment of turbine intermediate pressure and generator current for new rated conditions • Differential expansion detector – change in detector calibration and alarm
DNPS Unit 2 and 3	Stator water cooling service water restriction orifices – increase heat removal capacity

Question

22. Section 8.2.1 addresses the impact of the EPU on the condenser off-gas system; noting an increase of (radiolytic) hydrogen flow from 26.3 to 30.9 lb_m per hour under hydrogen water chemistry conditions. Additionally, the radioactive releases to be handled (held-up) by the off-gas system are estimated to increase proportionately to the power increase of 17%. Address how the combination of these proposed changes impact the design hold up times for the off-gas system; including the ability of the system to hold up a minimum of 30 minutes under conditions associated with 100 µCi/sec/Mwt release rates for noble gases; and (2) the operational impacts associated with the increase radiation shine effects caused by the increased feedwater hydrogen injection rates/main steam flow rates. As noted in Section 8.4.1.1, the impacts of hydrogen water chemistry on source terms are considered without credit for use of the effects of the NobleChem process, which considerably lowers the hydrogen feedwater injection requirements. Alternately, state if the use of NobleChem process to limit these effects is considered as part of the EPU basis.

Response

Holdup time in the offgas system, both in the delay line downstream of the recombiner and on the charcoal adsorbers, is affected only by main condenser air inleakage, and not by radiolytic hydrogen flow, which is removed in the offgas recombiner at the entrance to the system. Because EPU does not affect main condenser air inleakage, offgas system holdup times for noble gases are not affected by EPU. Therefore, an estimated increase in noble gas source term of 17% will result in a like increase in system release rate during periods of operation with significant fuel cladding leaks. However, because the current and expected fuel defect rate is extremely small, the actual offgas release rate is not expected to increase. Further, the maximum allowed release rate in the TS is not being changed for EPU.

As discussed in Reference 5, the calculated offsite dose due to turbine shine will increase in proportion to the uprate (i.e., 17%). This includes the effect of the increased hydrogen injection rate. However, the actual increase in turbine shine is expected to be less than the calculated increase. For a given feedwater hydrogen concentration, the increase in N-16 over baseline normal water chemistry conditions (i.e., no feedwater hydrogen) does not change for EPU. Therefore, the estimated 17% increase in N-16 due to EPU is offset by the approximately 19% increase in steaming rate (see PUSAR Sections 8.4.1 and 8.6), regardless of whether the plant is operating with or without hydrogen water chemistry (HWC) or NobleChem™. Under NobleChem™ operation, reduced feedwater hydrogen injection rates will significantly reduce the N-16 multiples resulting from HWC operation. Thus, for normal water chemistry operation and for HWC operation, offsite dose from turbine shine under EPU conditions will remain the same as current levels or will increase a small amount due to the small decrease in delay time in the steam lines from the increased steaming rate. For NobleChem™ application, turbine shine will decrease relative to levels prior to NobleChem™ application. Dose effects as presented in the EPU basis do not take credit for reduction due to NobleChem™, and therefore are bounding.

Question

23. Section 8.4.3 Clarify the statement in section 8.4.3 that the EPU does not change the design noble gas release rate from the fuel, specifically with respect to SRP 11.3 which provides guidance that the source term for noble gasses is a linear function of the power level and with respect to the stated original design bases of 0.2 Ci/sec after a thirty minute delay. Does the 0.2 Ci/sec original design basis bound the effect of a linear increase in power on the instantaneous off-gas limit noted in SRP 11.3?

Response

For the DNPS and QCNPS plants, the design basis is 0.2 Ci/s referenced to a 30 minute decay time. This design value was based upon past fuel performance at the time of original design (i.e., 1970 to 1972) and provided a margin of approximately a factor of two over the range in which these plants were expected to operate. Since that time period, improvements in fuel and operations have continually reduced the expected operating offgas values to small fractions of the original design basis. The expected offgas releases based upon current plant performance were estimated based on ANS Standard ANS/ANSI 18.1-1999 "Radiological Source for Normal Operation for Light Water Reactor," for the EPU condition. The results of this analysis show the offgas rate as evaluated by that standard to be a fraction of the original design basis. Therefore, the 0.2 Ci/sec design basis bounds the effect of the increase in power on the off-gas release rate.

Question

24. Section 8.4.3 Explain the stated expectation of no increase in fission product releases from the fuel as a result of EPU. Why won't the expected release rate increase in proportion to the reactor power level increase of 17%?

Response

To correct the statements in PUSAR Section 8.4.3, it is expected that some increase in fission product activity in reactor coolant will be seen. Using the formula in ANSI/ANS 18.1-1999, "Radiological Source Term for Normal Operation for Light Water Reactors," the increase would result in a calculated 12% increase in concentration. Even with this increase, the reactor coolant activity levels will be fractional parts of the design basis coolant concentrations.

Question

25. Section 10.1.1.1 addresses the main steam high energy line break and notes that the critical parameter affecting the HELB analyses is reactor dome pressure which is not being changed by the EPU. Do any of the HELB analyses credit isolation of the main steam lines to limit mass-energy released? If so, address the effects.

Response

The bounding main steam line break, a circumferential rupture that results in choked flow through the flow restrictor, credits isolation to limit the mass release. Since the steam pressure does not change due to EPU, the mass release from the limiting break is also unchanged. The DNPS and QCNPS UFSARs define the specific design basis break locations analyzed for HELB. All such postulated breaks in the main steam lines are located in the pipe tunnel. These breaks are isolated by any of three signals: the high steam line flow isolation, low steam line pressure isolation (in RUN mode), or high steam tunnel temperature isolation. Operability of all of these isolation signals are governed by the DNPS and QCNPS TS.

Question

26. Section 10.1.1.2 notes that for the EPU, the feedwater system line break results in a 6% increase in feedwater mass and energy release. The safety analysis further notes that design margins within the high energy line break analyses are conservative and remain bounding. Provide details of the main steam tunnel HELB analysis that addresses these margins, including major assumptions and results.

Response

The feedwater line break was used with a concurrent main steam line break to establish the peak pressure and the long term temperature environment in the main steam tunnel for DNPS and QCNPS.

The main steam tunnel pressure and temperature response to the design basis HELB was evaluated with the COMPARE computer code using the mass and energy releases at EPU conditions. A benchmark analysis was performed using the pre-EPU mass and energy releases. The same model was rerun using the EPU mass and energy releases. A comparison of the benchmark pressure to the design basis calculated pressure was used to determine the main steam tunnel pressure due to HELB at EPU conditions.

The licensing design basis pressure for the main steam tunnel for DNPS and QCNPS is 27.5 psia. The main steam tunnel peak calculated pressure is 27.2 psia at 0.1 seconds.

The COMPARE computer code was run using the pre-EPU model and blowdown flow to benchmark the licensing basis analysis. The calculated peak pressure was 27.26 psia at 0.11 seconds. The COMPARE code was then rerun using the EPU mass and energy releases. The calculated peak pressure is 27.45 psia at 0.11 seconds.

In order to compare design pressure with the calculated pressure, using the pre-EPU methods, the pre-EPU calculated pressure is multiplied by the ratio of the COMPARE post-EPU to pre-EPU calculated pressure. This provides an estimate of the pressure that would be calculated by the pre-EPU method using the post-EPU mass and energy releases. The peak calculated pressure due to EPU is estimated as follows.

Pressure (EPU) = [27.45 psia / 27.26 psia] * 27.2 psia = 27.38 psia

The pre-EPU design basis peak pressure used for the main steam tunnel for DNPS and QCNPS is 27.5 psia which bounds the calculated EPU main steam tunnel pressure of 27.38 psia.

For the pre-EPU design basis long term temperature profile, the COMPARE pre-EPU and EPU temperature values were compared. Within the accuracy of the calculation, there are no significant differences in the temperature profile. The values are within approximately 1°F of each other.

Therefore, it can be concluded that the pre-EPU design basis main steam tunnel environmental parameters bound the EPU values for the feedwater HELB concurrent with a main steam line break.

Question

27. Section 10.2 notes that moderate energy line break protection features are based on system parameters unchanged by the EPU. Are portions of the condensate and feedwater system considered within the scope of this analyses? If so, has the additional flow associated with operation of four condensate pumps been evaluated? Are any changes in flow or system operation being proposed for the condenser circulating water system to accommodate increased heat load of EPU, or will the EPU otherwise impact the potential for flooding from a line break in this system?

Response

The condensate and feedwater systems are considered high energy systems. Postulated flooding from these systems is not within the scope of the moderate energy line break analysis, but was covered under flooding from high energy breaks.

Safety related equipment in the turbine building that could be subjected to the effects of flooding are the containment cooling service water (CCSW) pumps at DNPS and the RHR service water pumps at QCNPS. At DNPS, two of these pumps are located in watertight vaults. At QCNPS, all of the RHR service water pumps are located in watertight vaults. These passive protection features are designed to protect against the limiting event of a circulating water system rupture, which could flood the building to the level of the river. This flooding event bounds the consequences of a postulated condensate system rupture, regardless of the number of condensate pumps operating.

Feedwater system ruptures could affect safety-related equipment in the main steam tunnel due to flooding. The pre-EPU analysis of such ruptures assumed the tunnel would flood completely. This analysis therefore bounds the EPU case.

The circulating water system can accommodate the EPU heat load at the current system flow rate. The existing protective features for a circulating water system rupture include a trip of the pumps on high level in the condenser pit area. The ultimate consequences of such a rupture are due to subsequent gravity feed resulting in the flood water level reaching river level. Existing flood protection features are not affected by EPU.

Question
28. Section 11.3 notes that the quantity of spent fuel will not be affected by the uprate; although the short-term radioactivity will be higher but within limits. Please clarify this statement. Is there not an expectation that additional spent fuel assemblies will be required to support the 17% power increase; or is the entire power uprate accommodated in increased burn-up of fuel assemblies?

Response
This statement is incorrect. The statement on this issue in the Environmental Report (Attachment D to Reference 1), Section 3.3, "Radiological Environmental Impacts," is correct. The quantity of spent fuel discharged at the end of each uprated cycle will be larger than that discharged from the pre-EPU cycles.

Question
29. Is the capacity of the hardened vent sufficient to accommodate the power uprate?

Response
The design basis for the containment hardened vent is to mitigate loss of decay heat removal sequences, and to prevent further pressurization with the containment at its pressure limit. The vent was reanalyzed for EPU conditions to ensure this basis was still met.

For DNPS, the hardened vent will have a capacity of 1% of RTP after EPU. The QCNPS hardened vent will have a capacity of 0.85% of RTP after EPU. The EPU decay heat curve reaches 1% at 11,000 seconds, or 3.1 hours, and reaches 0.85% at 20,000 seconds, or 5.6 hours. Under EPU conditions, the containment will not reach the pressure limit until 20 hours after a loss of decay heat removal. The DNPS and QCNPS hardened vents are thus capable of relieving EPU decay heat with ample margin to the time when venting is required. Therefore, the

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existing DNPS and QCNPS hardened vent capacity is sufficient to accommodate the power uprate.

Question

30. The environmental qualification of non-metallic components, (i.e. seals, gaskets, lubricants, diaphragms, etc.) has not been addressed. Please demonstrate that plant operations at the proposed EPU level will have no impact on the environmental qualification of mechanical equipment located both inside and outside containment.

Response

Operating and environmental conditions are included in procurement specifications for such material.

Changes in operating conditions as well as normal and accident environmental conditions have been determined for EPU. These changes, as indicated in PUSAR Tables 4-1, "DBA-LOCA Containment Performance Results," 10-1, "High Energy Line Break," and 10-2, "Environmental Changes for Equipment Qualification and Affected Equipment Types," are very minor relative to the range of conditions normally allowed for such materials. The most severe change in conditions is due to the post LOCA increase in the torus water temperature. Due to the potentially higher fluid operating temperature of the Core Spray and LPCI pumps at DNPS only, which use process water for bearing cooling, the bearing lube oil is being changed for EPU. No other changes in materials of this type were identified for operation at EPU conditions.

Figure 1
Re-Rated Conditions for Feedwater Heaters

Feedwater Heater	**Design Conditions Pre-EPU**	**Design Conditions Post-EPU**
LP Drain Cooler A-2		
Design Pressure (PSIG)	50	50
Design Temperature (°F)	300	300
LP Heater #A1		
Design Pressure (PSIG)	50	50
Design Temperature (°F)	298	298
LP Heater B		
Design Pressure (PSIG)	50	50
Design Temperature (°F)	350	350
LP Heater C		
Design Pressure (PSIG)	75 (DNPS), 83 (QCNPS)	100
Design Temperature (°F)	350	350
HP Heater D		
Design Pressure (PSIG)	150	178
Design Temperature (°F)	450	450

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Table 1
Remarks on Figures 2 - 11

2 & 3	Pressure and temperature response from short term DBA-LOCA analysis	Break flow rate and enthalpy are calculated with LAMB (with Moody's slip critical flow model), using the model representing both Dresden and Quad Cities, and these break flow values are used as input to the M3CPT code. The initial wetwell and suppression pool temperature was conservatively assumed to be 98°F, as compared with 95°F assumed in the long-term SHEX analysis. The initial drywell and wetwell pressure are assumed to be their maximum expected normal operating values. The peak drywell pressure for the current power, based on the current method, was predicted to be lower than the UFSAR value, but higher than the peak value obtained during the Long Term Program (LTP) for Mark I containment, as shown below. UFSAR Current Analysis LTP Dresden 47 psig 42.8 psig 41.2 psig Quad Cities 47 psig 42.8 psig 40.6 psig The difference between the original UFSAR analysis and the current analysis may be mainly due to differences in the blowdown flow rates, although the same critical flow model (Moody's slip model) was used for both analyses. Depending upon the vessel modeling that provides input conditions for the critical flow model, the blowdown values could be different. The UFSAR indicated that the DBA-LOCA blowdown values used in that analysis might be over-predicted, which would cause the over-prediction of peak drywell pressure. It is noted that the current method resulted in higher peak drywell pressure, compared to the LTP analysis that was reviewed and approved by the NRC. The LTP analysis used the vessel blowdown model built into the M3CPT code, as compared with the current analysis based on the LAMB blowdown model.
4 & 5	Dresden pressure and temperature response from long term DBA-LOCA analysis with direct pool cooling	The wetwell and suppression pool temperature was assumed to be 95°F. The initial drywell and wetwell pressure were assumed to be their maximum expected normal operating values. It was conservatively assumed that the suppression pool surface stays unperturbed. This assumption results in an unrealistically high wetwell temperature early in the event, because of compression effects, while allowing no mixing between the airspace and pool even during the blowdown phase. Only one RHR pump was assumed to be available to maximize the pool temperature response
6 & 7	Dresden pressure and	The wetwell and suppression pool temperature was assumed to be 95°F. The initial drywell

	temperature response from DBA-LOCA analysis for NPSH	and wetwell pressure were assumed to be their minimum expected values. Two cases, short-term and long-term, were analyzed using different assumptions regarding operation of LPCI/containment cooling pumps. The short-term case, which applies to the time period before 600 seconds, assumed that water from four LPCI pumps flows into the drywell through the break to minimize the pressure response. The long-term case (applying to the time period after 600 seconds) assumed that before 600 seconds two LPCI pumps are operating without dumping the water into the drywell, and at 600 seconds one of the two LPCI pumps is switched to containment spray, while turning off the other. This case will maximize the pool temperature response. For NPSH evaluations, the results for the short-term case are used for the time period before 600 seconds, and the long-term results are used for the time period after 600 seconds. Figures 5 and 6 show the combined results (short-term results before 600 seconds and long-term results after 600 seconds). Because of different assumptions between the two cases (before and after 600 seconds), Figures 5 and 6 exhibits sudden changes in the pressure and temperature response at 600 seconds. For instance, the wetwell pressure is approximately 20 psia (the short-term result) at 600 seconds as a result of low drywell pressure (due to high (4 pumps) LPCI flow into the drywell), which is followed by opening of wetwell-drywell vacuum breakers. Right after 600 seconds, the wetwell pressure is approximately 30 psia (the long-term results), because of the difference in the event scenario between the short-term and long-term cases.
8 & 9	Quad Cities pressure and temperature response for long term DBA-LOCA with direct pool cooling	Same assumptions as for the Dresden analysis, using Quad Cities RHR heat exchanger K-value of 262 Btu/sec-°F compared with 281.7 Btu/sec-°F for Dresden.
10 & 11	Quad Cities pressure and temperature response for DBA-LOCA for NPSH	Same assumptions as for the Dresden analysis, using Quad Cities RHR heat exchanger K-value of 262 Btu/sec-°F compared with 281.7 Btu/sec-°F for Dresden. As mentioned above for the Dresden analysis, two cases, short-term and long-term, were analyzed using different assumptions regarding operation of LPCI/RHR (containment cooling) pumps. The combined results (short-term results before 600 seconds and long-term results after 600 seconds) are plotted in Figures 9 and 10. Because of different event scenarios between the two cases, Figures 9 and 10 show sudden changes in the pressure and temperature response at 600 seconds.

Figure 2
Dresden and Quad Cities Short-Term DBA-LOCA Containment Pressure Response

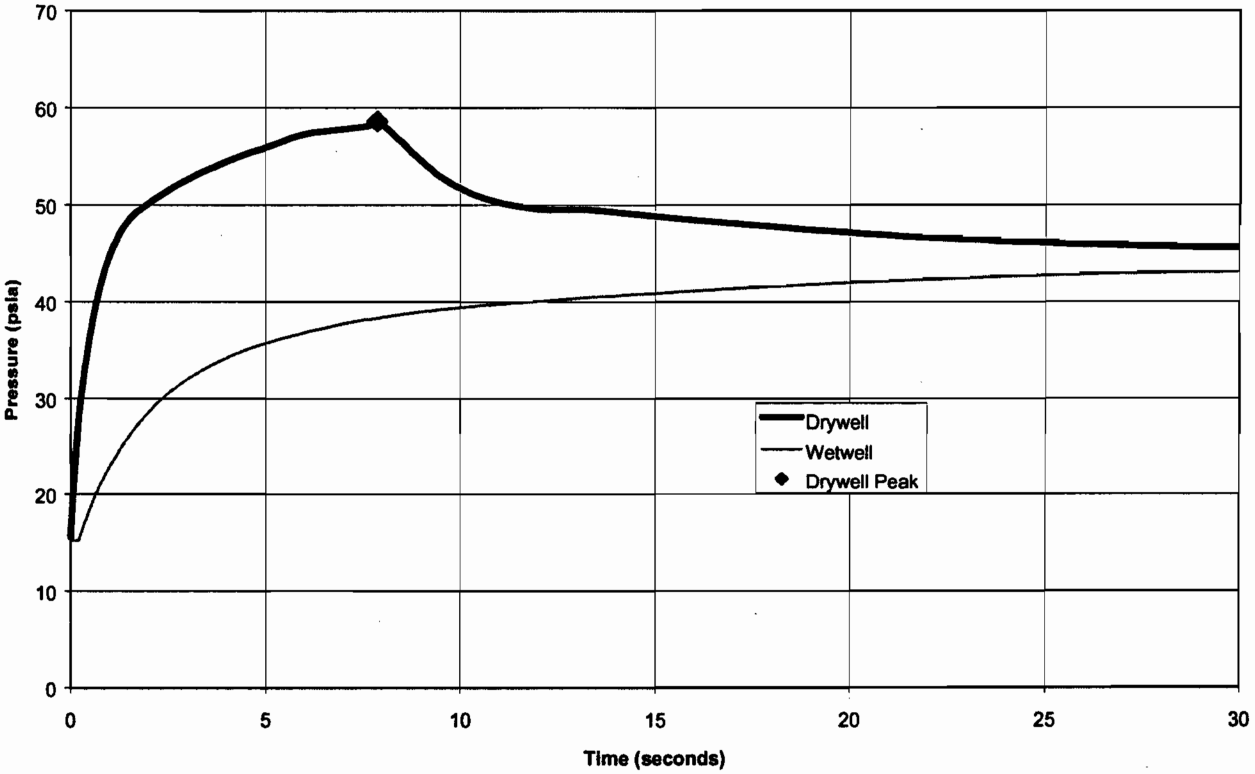
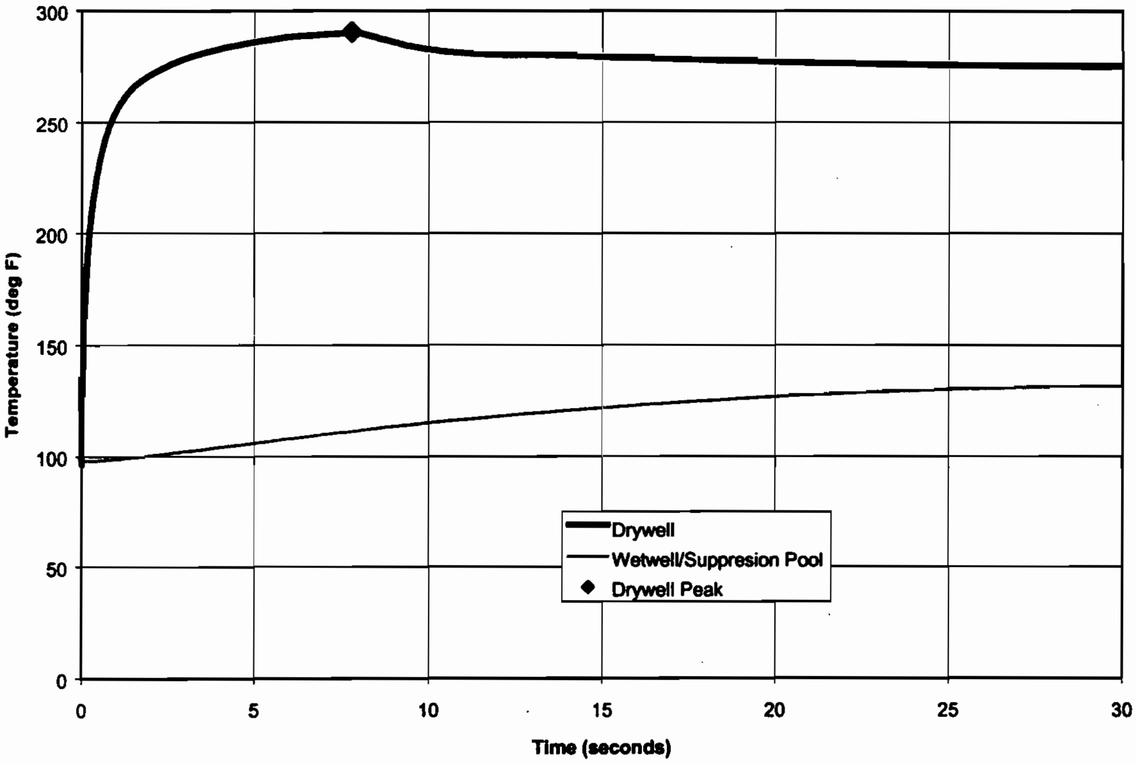
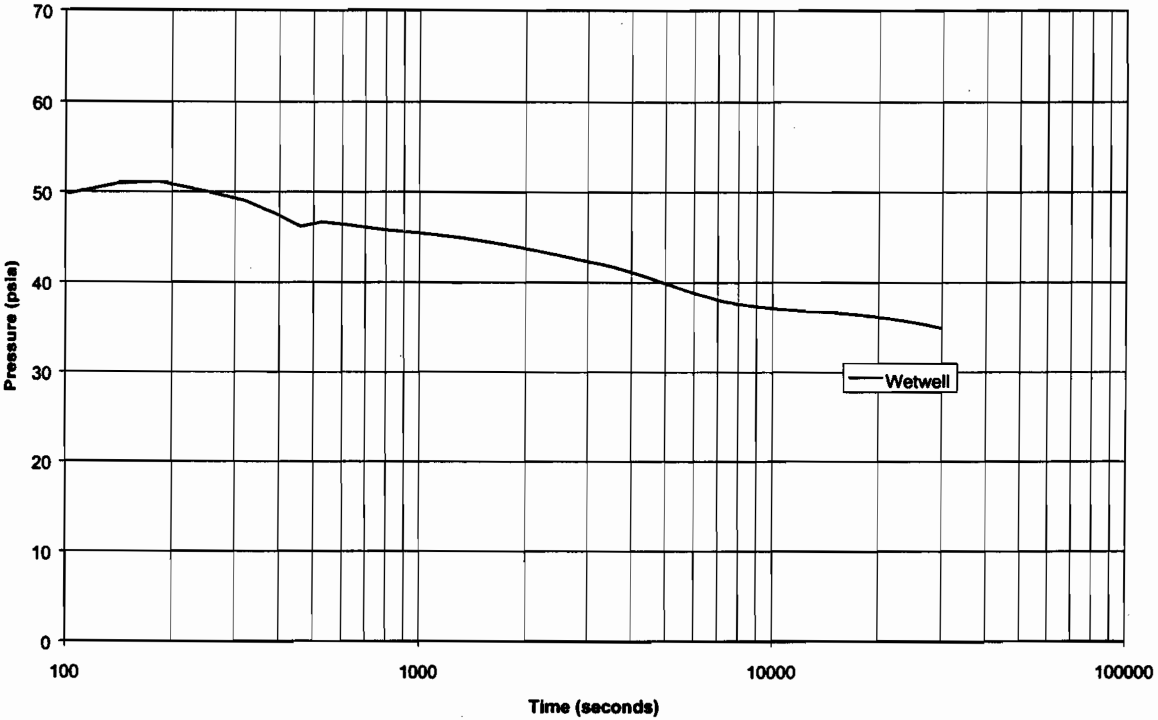


Figure 3
Dresden and Quad Cities Short-Term DBA-LOCA Containment Temperature Response



Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 4
Dresden DBA-LOCA with Direct Pool Cooling
Containment Pressure Response



Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 5
Dresden DBA-LOCA with Direct Pool Cooling
Containment Temperature Response

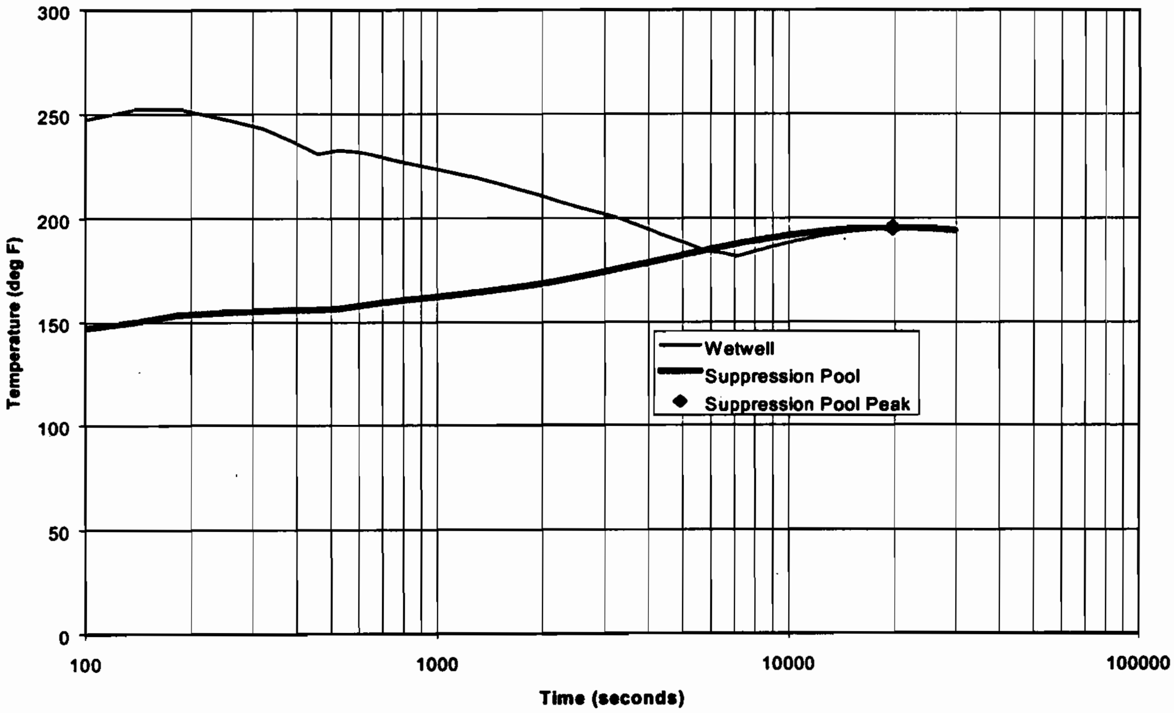
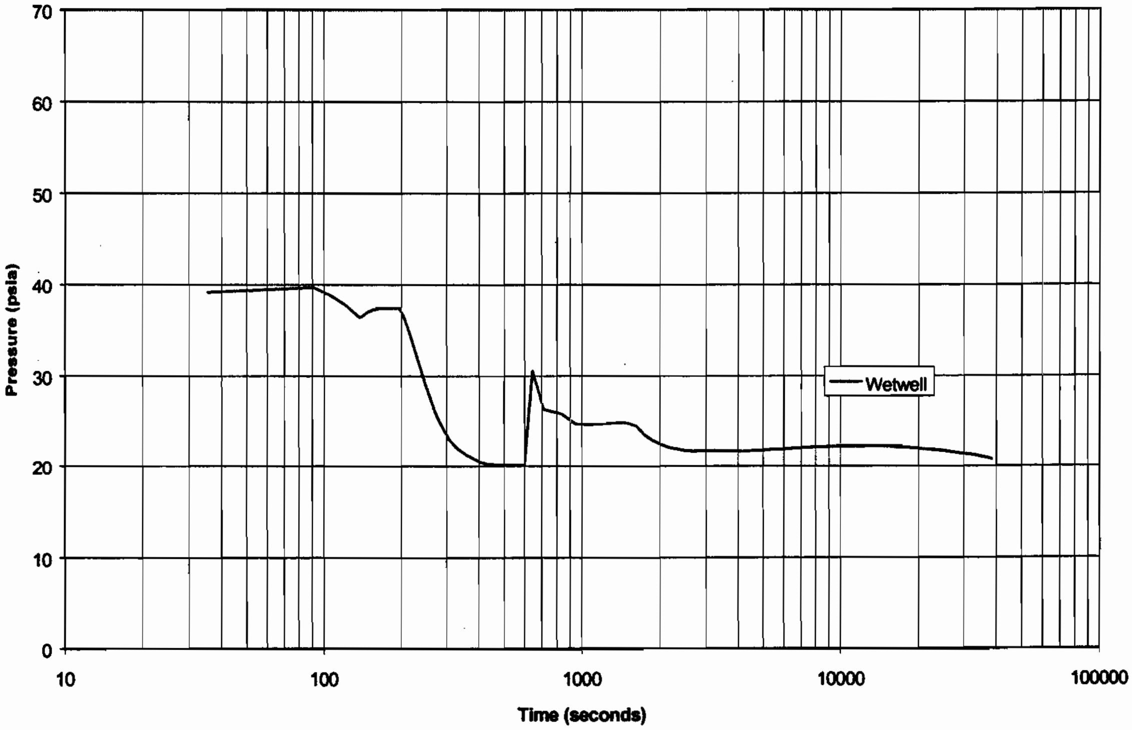


Figure 6
Dresden DBA-LOCA for NPSH
Containment Pressure Response



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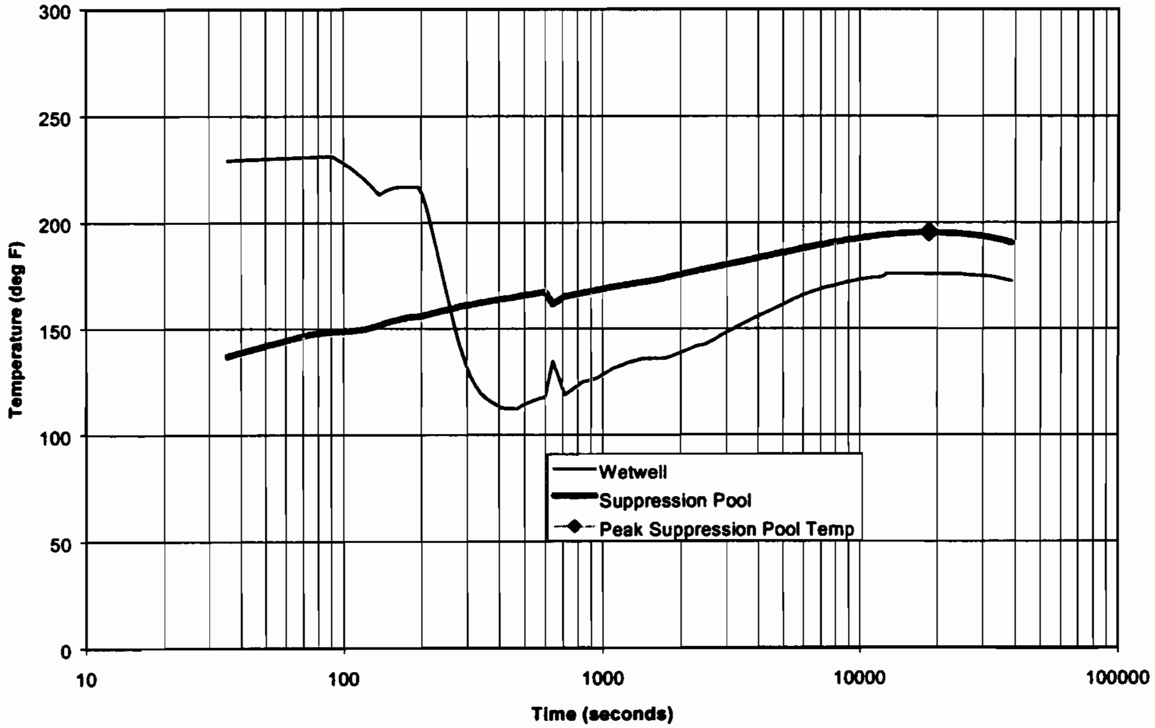
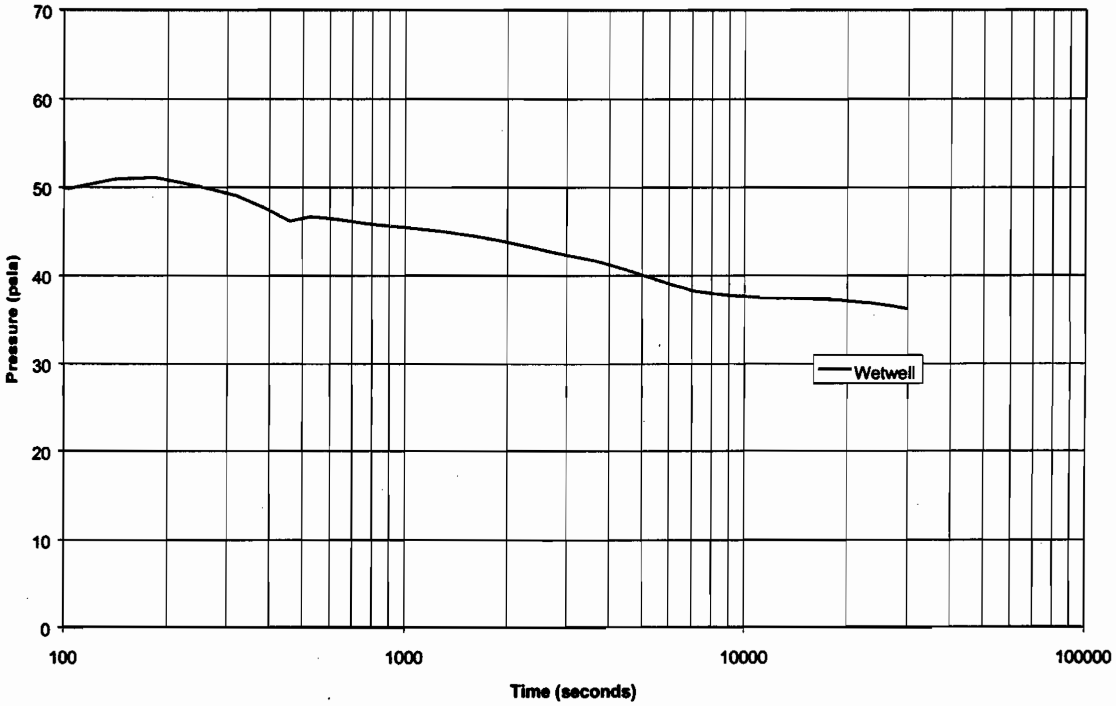
Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 7
Dresden DBA-LOCA for NPSH
Containment Temperature Response



Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 8
Quad Cities DBA-LOCA with Direct Pool Cooling
Containment Pressure Response



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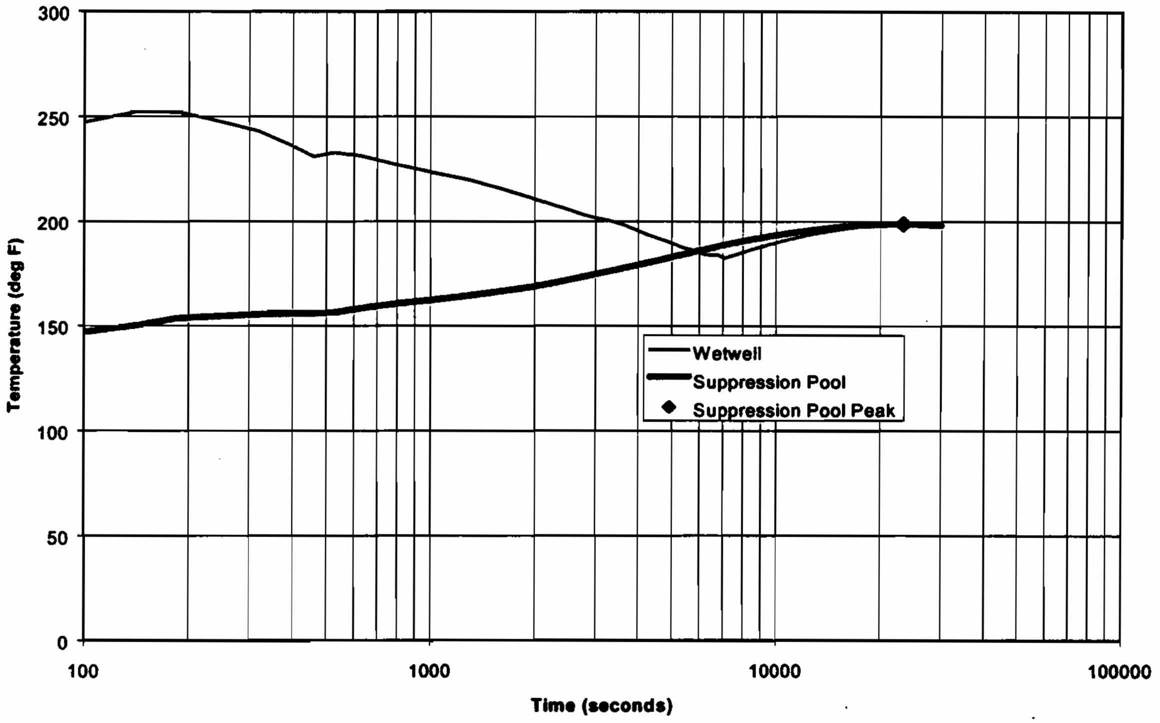
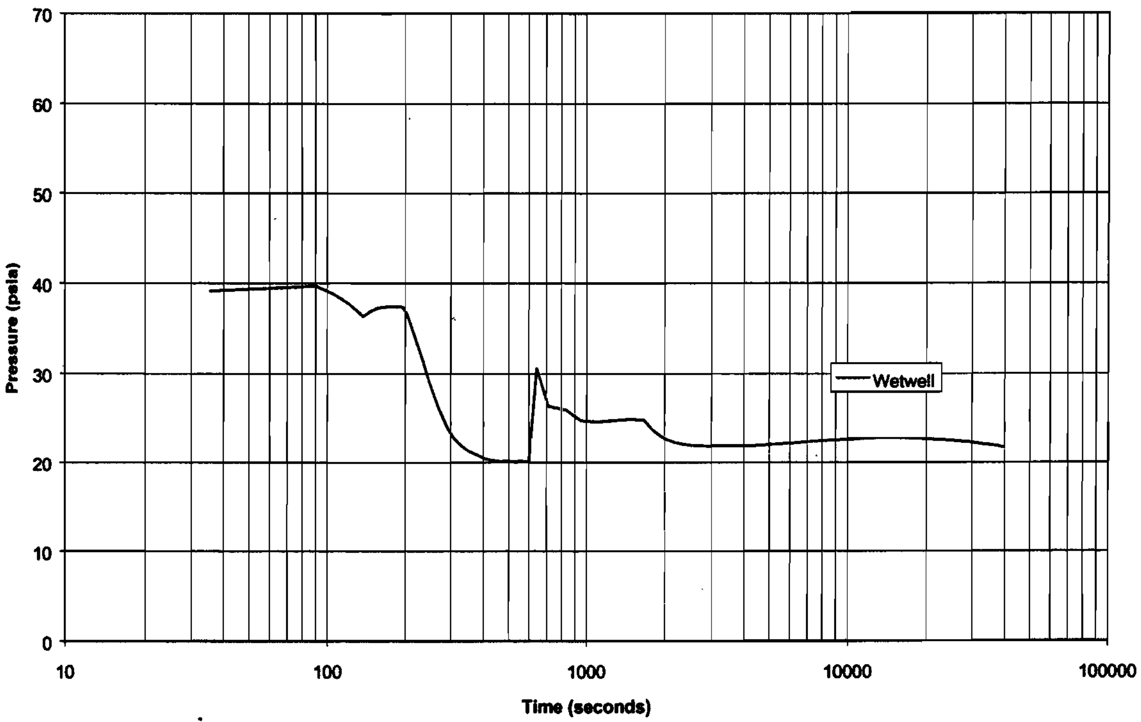
Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 9
Quad Cities DBA-LOCA with Direct Pool Cooling
Containment Temperature Response



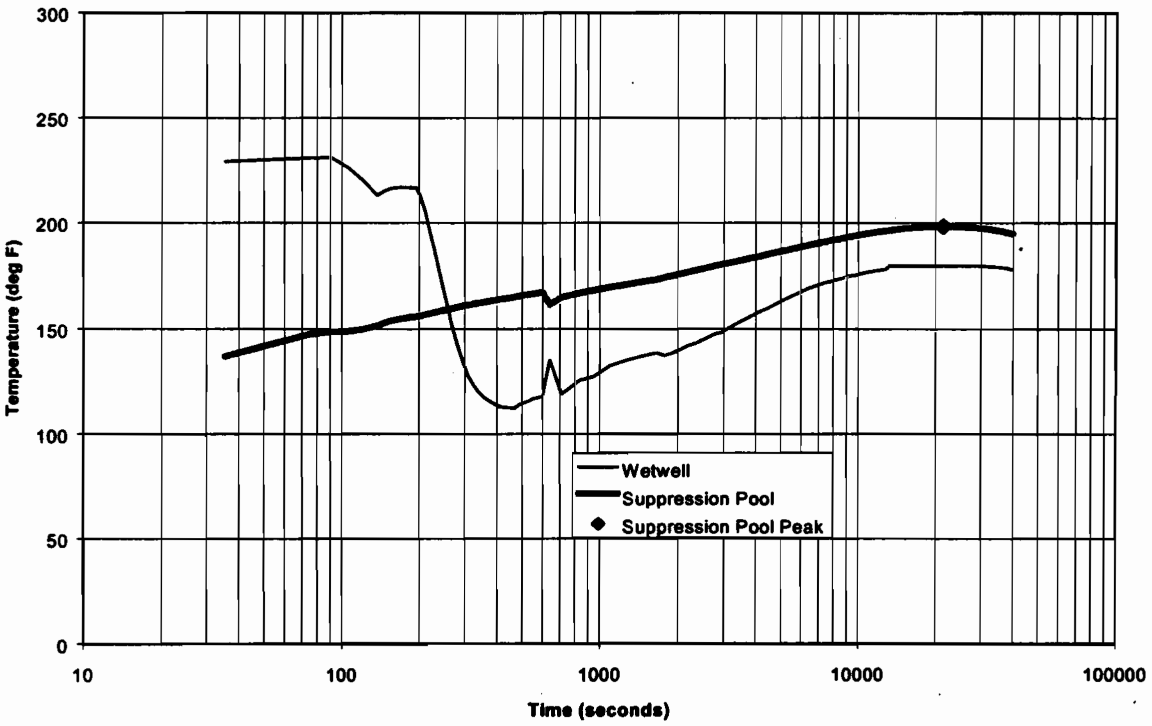
Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 10
Quad Cities DBA-LOCA for NPSH
Containment Pressure Response



Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 11
Quad Cities DBA-LOCA for NPSH
Containment Temperature Response



Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Figure 12

Hydrogen Generation Rate in Containment Following Loss of Coolant Accident

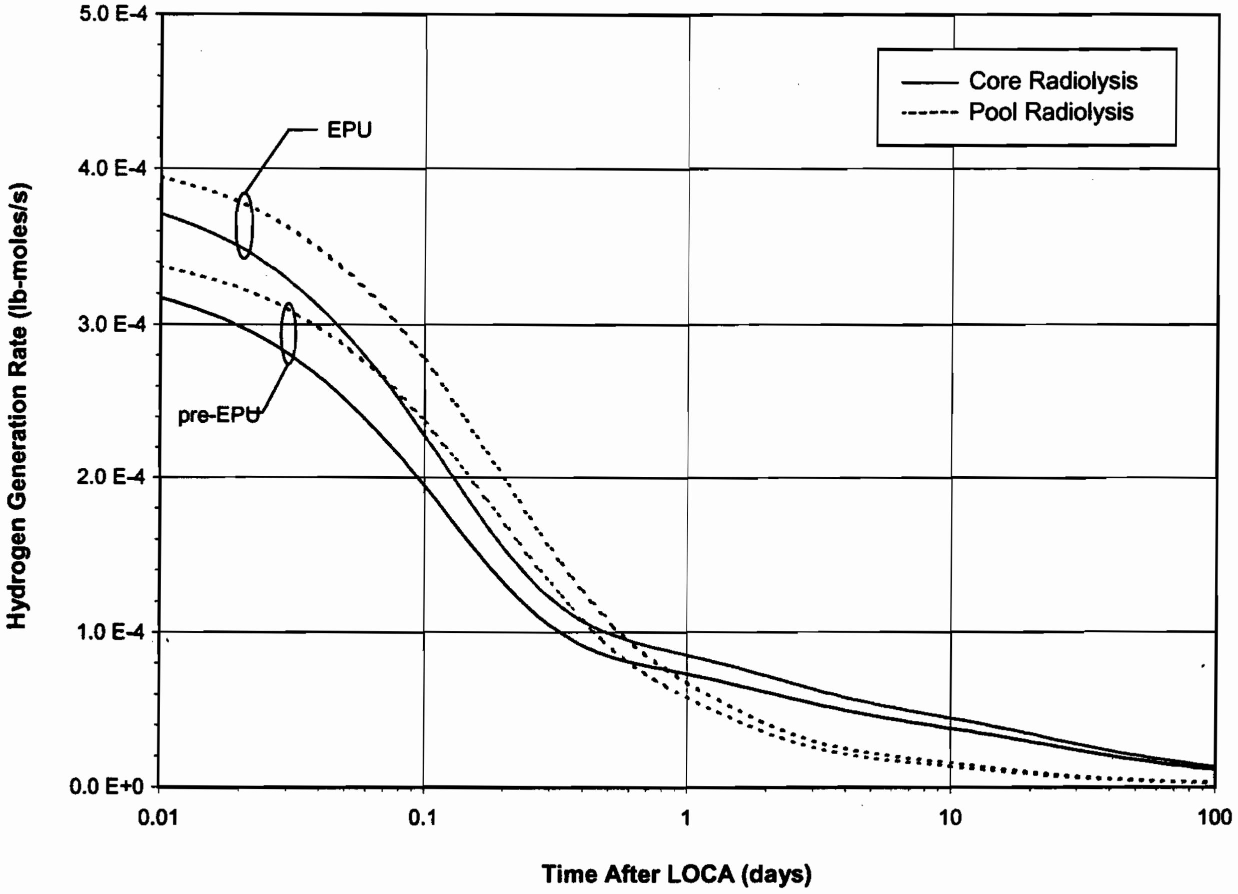


Figure 13
Containment Hydrogen and Oxygen Concentrations Without Nitrogen Containment Atmosphere Dilution System

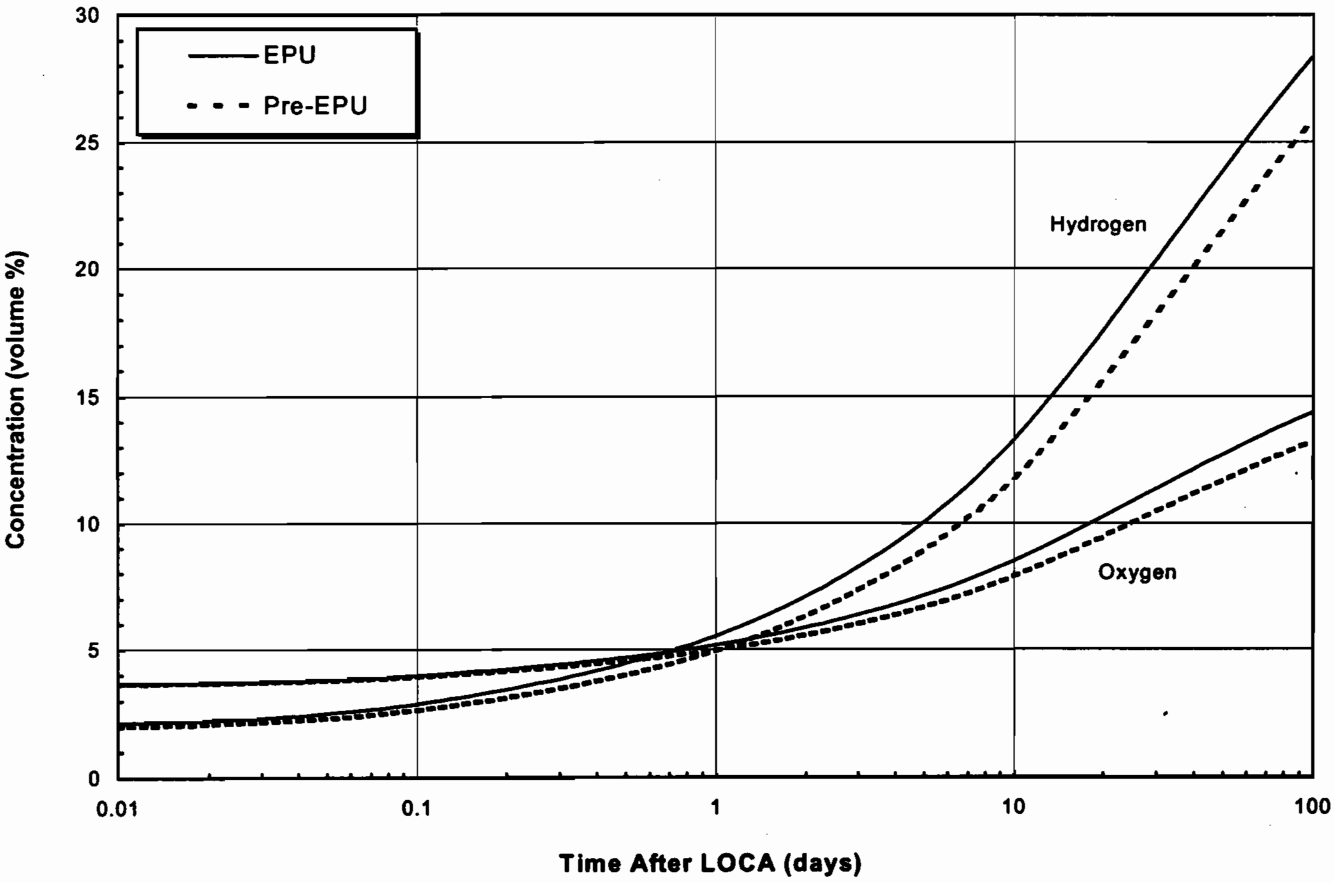


Figure 14
Containment Hydrogen and Oxygen Concentrations With Nitrogen Containment Atmosphere Dilution System Operation

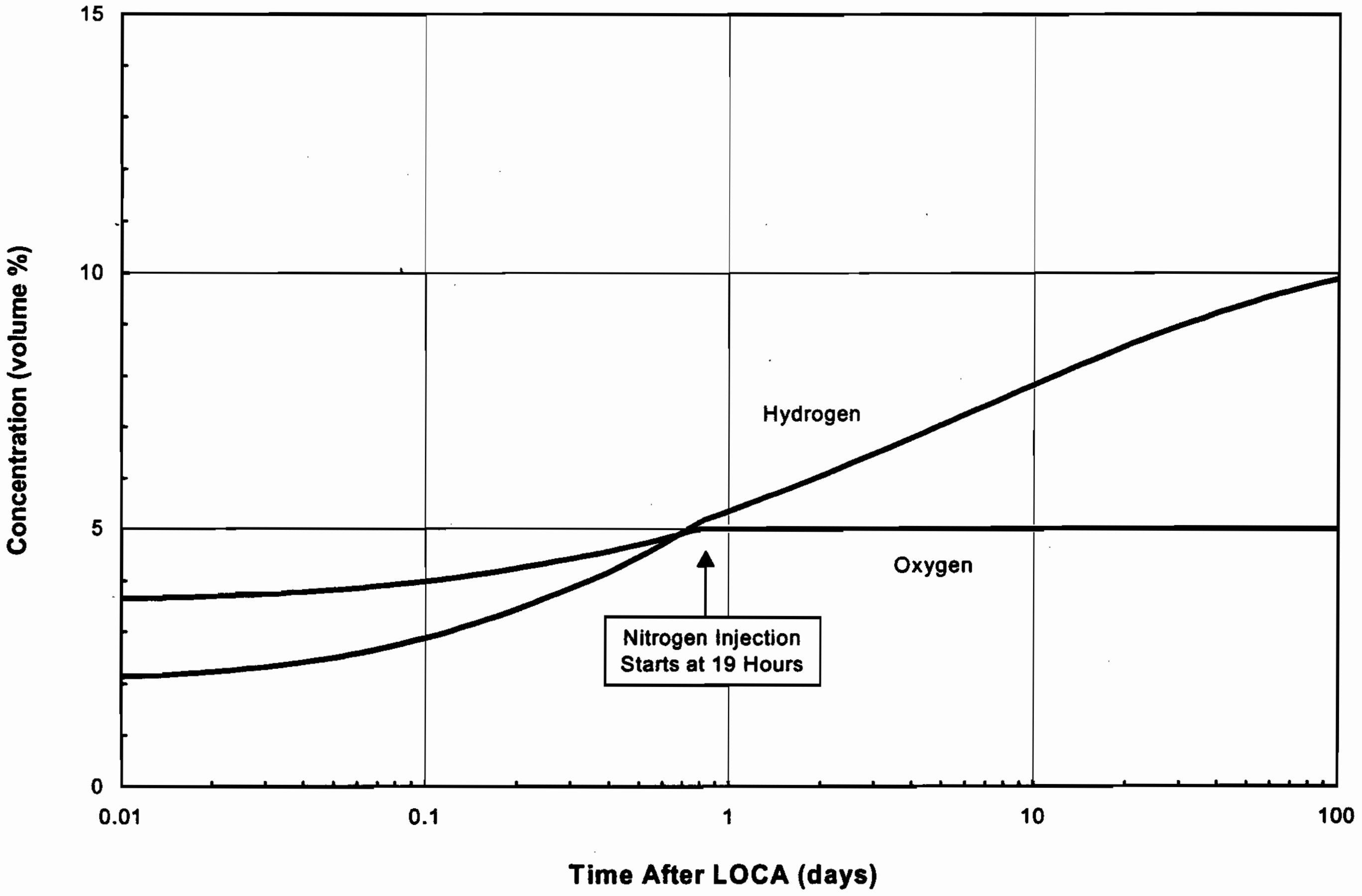


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Figure 15
NCAD System Nitrogen Cumulative Usage

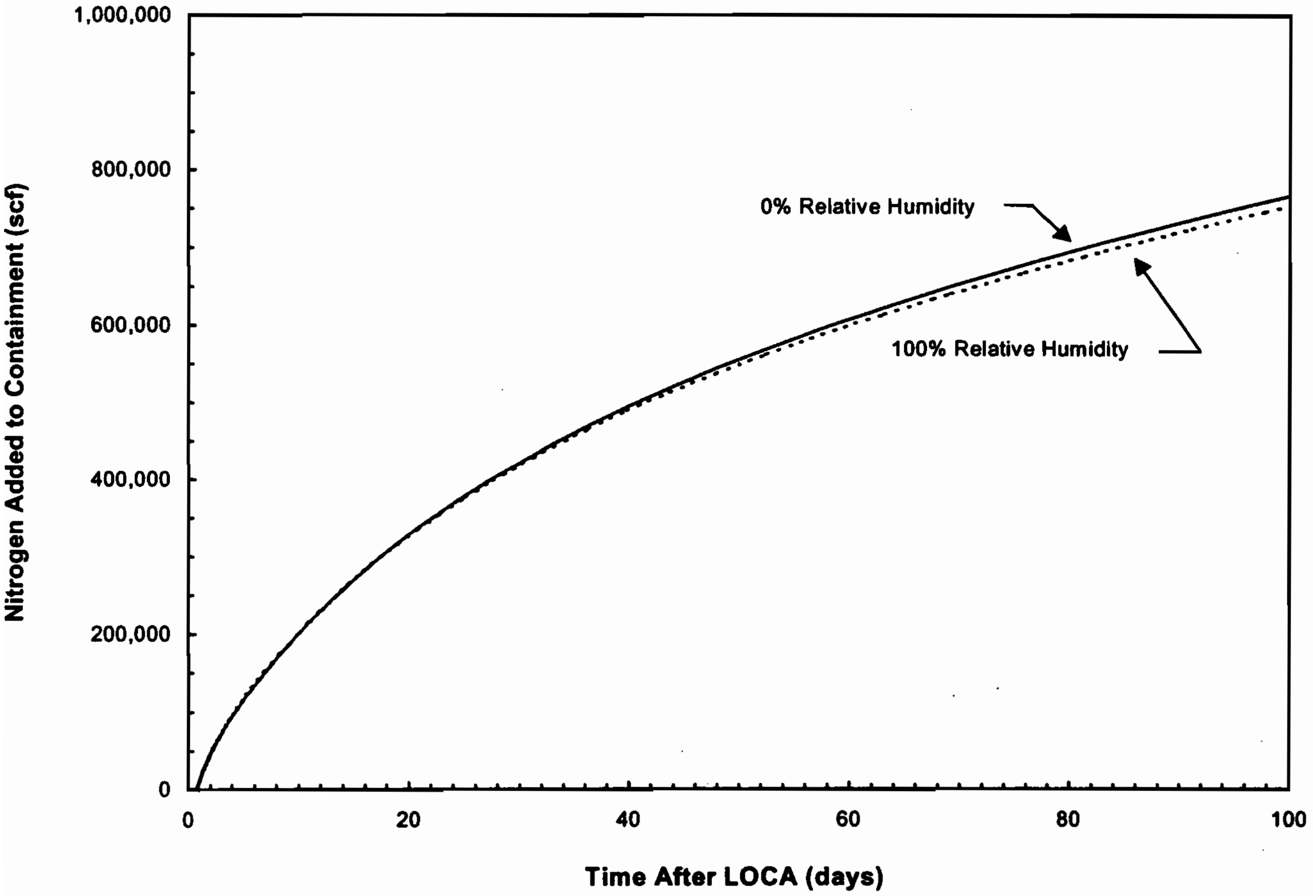
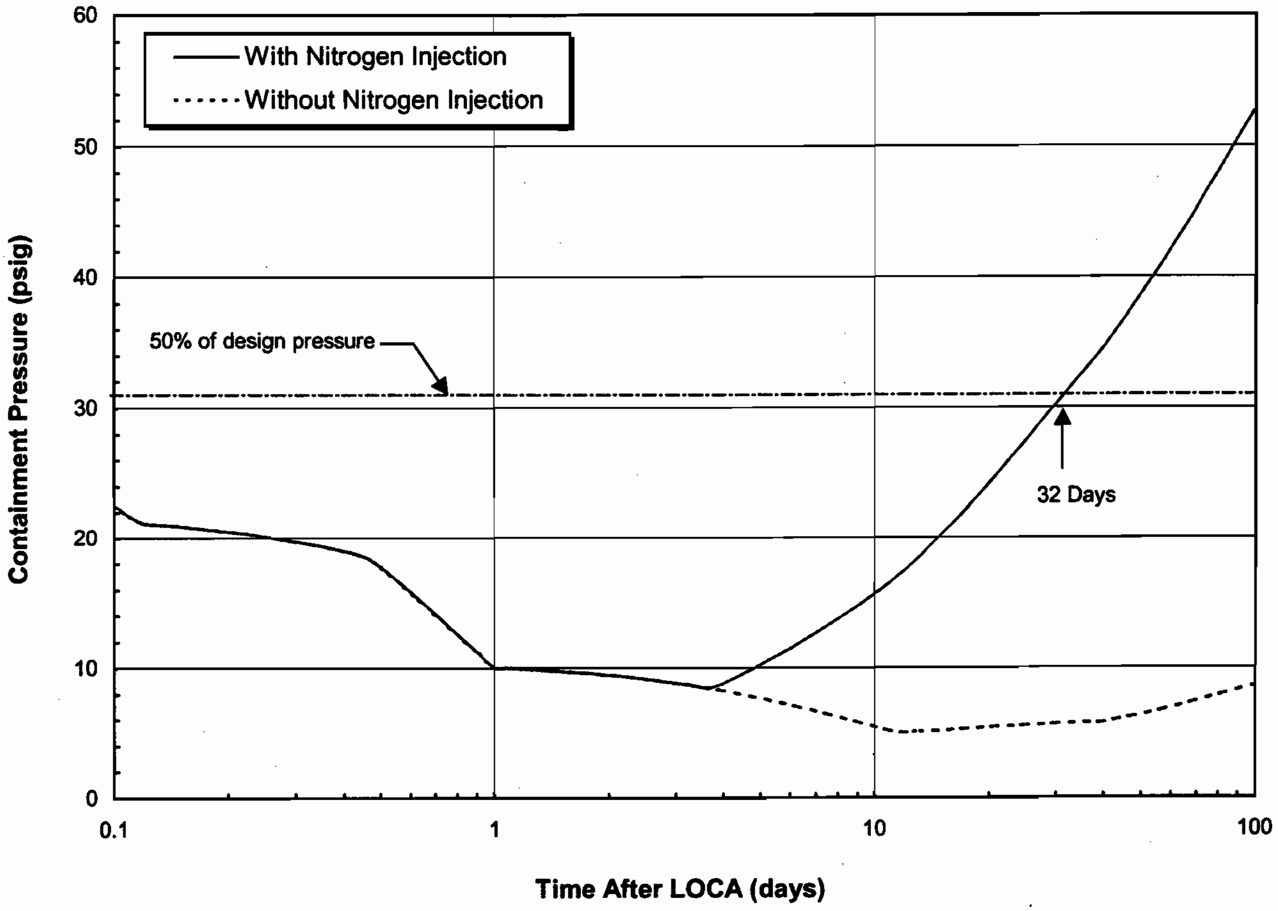


Figure 16
Containment Pressure Response to Nitrogen Containment Atmosphere Dilution System Operation



Attachment A
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

References

1. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

2. Licensing Topical Report, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32424P-A, Class III, February 1999

3. Letter from U. S. NRC to G.L. Sozzi (General Electric), "Staff Position Concerning General Electric Boiling-Water Reactor Extended Power Uprate Program," dated February 8, 1996

4. Letter from U. S. NRC to I. Johnson (Commonwealth Edison Company), "Issuance of Amendments," dated April 30, 1997

5. Letter from R. M. Krich (Exelon Generation Company, LLC) to U. S. NRC, "Additional Health Physics Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated May 29, 2001

Attachment B
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Draft Revision to Updated Final Safety Analysis Report Section 6.2.1.3

<u>Revised Pages for Dresden Nuclear Power Station</u>

6.2-24
Insert page for 6.2-24

<u>Revised Pages for Quad Cities Nuclear Power Station</u>

6.2-17
Insert page for 6.2-17

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

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

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

400
7/24/01

~~The pressure and temperature responses of the containment, as originally calculated using Moody's model, are shown in Figures 6.2-19 and 6.2-20. As can be seen in Figure 6.2-19, the calculated peak drywell pressure is 47 psig, which is well below the design allowable pressure of 62 psig.~~

INSERT B

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

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

Insert A to Section 6.2.1.3.2.1 (Page 6.2-24)

Based on the methodology described in Section 6.2.1.3.2.1, the containment pressure and temperature responses are evaluated at the core thermal power of 3016 MWt (102% of the rated thermal power of 2957 MWt). The short-term results are presented in Figures 6.2-31a and 6.2-32a, and the long-term results in Figures 6.2-19a and 6.2-20a. It is noted that the short-term response calculations are based on input assumptions that maximize the pressure response, whereas the suppression pool temperature response is of primary concern in the long-term response calculations. As shown in Figure 6.2-31a, the peak drywell pressure is calculated to be 43.9 psig. (For historical purposes, the containment pressure and temperature responses (short-term and long-term combined), as originally calculated for the original rated thermal power of 2527 MWt, are shown in Figures 6.2-19 and 6.2-20.)

As the size of the vessel orifice increases, the vessel blowdown rate is overpredicted and the overprediction of peak drywell pressure increases. This trend is illustrated in Figure 6.2-15, where calculated and measured peak drywell pressures are compared. In no case did the model underpredict the test data.

CWB 7/14/01

INSERT A

~~The calculated containment pressure and temperature responses are shown in Figures 6.2-16 and 6.2-17. As shown in Figure 6.2-16, the calculated peak drywell pressure is 47 psig, which is well below the design pressure of 56 psig.~~

6.2-29 Revised analysis of the pressure and temperature response of a similar primary containment (Dresden Unit 2) following an actual LOCA was performed in which peak drywell temperature was calculated to be 320°F. This concern was addressed in Dresden Unit 2 reports entitled "Special Report of Incident of June 5, 1970" and "Supplement to the Special Report of June 5, 1970". The LOCA which caused this peak drywell temperature was a special case small break LOCA (actually a steam leak) which did not have any effect on the design temperature and pressure of the containment (281°F, 56 psig) because the pressure associated with the higher temperature was not a saturation pressure. The resulting combination of slightly higher temperature and significantly lower pressure was less severe than design conditions.

6.2.1.3.2.2 T400 CWB 1/5/01

~~6.2.1.3.3~~ Containment Long Term Response to A Design Basis Accident

6.2-30 After the blowdown immediately following a postulated recirculation line break, the temperature of the suppression chamber water would approach 130°F and the primary containment system pressure equalizes at about 25 psig. Most of the noncondensible gases would be transported to the suppression chamber during blowdown. As condensation in the drywell began, the drywell pressure would decrease and the gases would redistribute between the drywell and the suppression chamber via the vacuum-breaker system.

6.2-31 The core spray system would remove decay heat and stored heat from the core, thereby minimizing core heatup and limiting metal-water reaction to less than 0.1%. The core spray system would transport core heat out of the reactor vessel through the broken recirculation line in the form of hot water. This hot water would flow from the drywell into the suppression chamber via the connecting vent pipes. Steam flow would be negligible. The energy transported to the suppression chamber water would ultimately be removed from the primary containment system by the residual heat removal (RHR) system heat exchangers.

Prior to activation of the containment cooling mode of RHR (arbitrarily assumed to occur at 600 seconds after accident initiation) at least three RHR pumps in the low pressure coolant injection (LPCI) mode would add liquid to the reactor vessel along with core spray. After the reactor vessel was flooded, the excess flow would discharge through the break into the drywell. This flow, in addition to heat losses to the walls, would offer considerable cooling to the drywell and would cause a depressurization of the containment as the steam in the drywell condensed. At 600 seconds, the RHR system may be transferred from the LPCI mode to the containment cooling mode. The containment spray would not be necessary at all and the transfer to containment cooling mode would not be necessary for several hours.

Insert A to Section 6.2.1.3.2.1 (Page 6.2-17)

Based on the methodology described in Section 6.2.1.3.2, the containment pressure and temperature responses are evaluated at the core thermal power of 3016 MWt (102% of the rated thermal power of 2957 MWt). The short-term results are presented in Figures 6.2-22a and 6.2-25a, and the long-term results in Figures 6.2-16a and 6.2-18a. It is noted that the short-term response calculations are based on input assumptions that maximize the pressure response, whereas the suppression pool temperature response is of primary concern in the long-term response calculations. As shown in Figure 6.2-22a, the peak drywell pressure is calculated to be 43.9 psig, which is well below the design pressure of 56 psig. (For historical purposes, the containment pressure and temperature responses (short-term and long-term combined), as originally calculated for the original rated thermal power of 2511 MWt, are shown in Figures 6.2-16 and 6.2-17.)

Attachment C
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Affidavit for Withholding Portions of Attachment A from Public Disclosure

General Electric Company

AFFIDAVIT

I, **George B. Stramback,** being duly sworn, depose and state as follows:

(1) I am Project Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Attachment 1 to letter GE-DQC–EPU-01-464, *Plant Systems RAIs*, (GE Proprietary Information), dated August 6, 2001. The proprietary information is delineated by bars marked in the margin adjacent to the specific material in the Attachment 1 to Letter GE-DQC–EPU-01-464, *GE Response to NRC Plant Systems RAIs.*

(3) In making this application for withholding of proprietary information of which it is the owner, GE relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), 2.790(a)(4), and 2.790(d)(1) for "trade secrets and commercial or financial information obtained from a person and privileged or confidential" (Exemption 4). The material for which exemption from disclosure is here sought is all "confidential commercial information", and some portions also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by General Electric's competitors without license from General Electric constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals cost or price information, production capacities, budget levels, or commercial strategies of General Electric, its customers, or its suppliers;

d. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, of potential commercial value to General Electric;

e. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in both paragraphs (4)a. and (4)b., above.

(5) The information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist or other equivalent authority, by the manager of the cognizant marketing function (or his delegate), and by the Legal Operation, for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GE are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains further details regarding the GE proprietary report NEDC-32961P, *Safety Analysis Report for Quad Cities 1 & 2 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, and NEDC-32962P, *Safety Analysis Report for Dresden 2 & 3 Extended Power Uprate,* Class III (GE Proprietary Information), dated December 2000, which contain detailed results of analytical models, methods and processes, including computer codes, which GE has

developed, obtained NRC approval of, and applied to perform evaluations of transient and accident events in the GE Boiling Water Reactor ("BWR").

The development and approval of these system, component, and thermal hydraulic models and computer codes was achieved at a significant cost to GE, on the order of several million dollars.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GE asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GE's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GE's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GE would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GE of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

STATE OF CALIFORNIA)
) ss:
COUNTY OF SANTA CLARA)

George B. Stramback, being duly sworn, deposes and says:

That he has read the foregoing affidavit and the matters stated therein are true and correct to the best of his knowledge, information, and belief.

Executed at San Jose, California, this 6th day of August 2001.

George B. Stramback
George B. Stramback
General Electric Company

Subscribed and sworn before me this 6TH day of AUGUST 2001.

Anna Hanlin
Notary Public, State of California

ANNA HANLIN
Commission # 1184507
Notary Public - California
Santa Clara County
My Comm. Expires Jun 19, 2002

Attachment D
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2

Additional Plant Systems Information Supporting the License Amendment Request to Permit Uprated Power Operation (non-proprietary version)

Attachment D
Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
Dresden Nuclear Power Station, Units 2 and 3
Quad Cities Nuclear Power Station, Units 1 and 2
(Non-Proprietary Version)

This attachment contains responses to NRC Questions 1 through 8, 12, 15, and 17 through 30. Responses to NRC Questions 9, 10, 11, 13, 14, and 16 will be provided separately.

Question

1. *During a telephone call on April 30, 2001, your staff noted that changes were being planned in the feedwater and condensate systems to improve the trip avoidance capability of the plant from transients initiated in these systems at the extended power uprate (EPU) full power conditions. These changes were not described in your application. For both Dresden and Quad Cities, describe the various existing features and planned changes (e.g., delayed tripping of a main feedwater pump on low suction pressure; reactor recirculation pump runbacks) which will minimize plant trips from these conditions. Describe plant startup testing and/or post modification testing which will examine these modifications.*

Response

The EPU feedwater and condensate modifications being implemented to avoid spurious reactor scrams are the addition of a reactor recirculation pump runback feature, changes to the reactor feedwater pump low suction pressure trip logic, and changes to the scaling of feedwater control and indication loops.

Reactor Recirculation Pump Runback

A reactor recirculation pump runback is being added as a trip avoidance feature to reduce the potential for a reactor low water level scram on the loss of either a feedwater or condensate pump at extended power uprate (EPU) conditions. In addition, the reactor low water level scram and isolation setpoint is being changed as discussed in Reference 1, Attachment E, "Power Uprate Safety Analysis Report," (PUSAR), Section 5.3.8. A dynamic analysis of a single feedwater pump trip at EPU conditions indicates that an automatic reactor recirculation runback can reduce core flow and thermal power to within the capability of the running feedwater pumps and avoid a reduction in reactor water level to the scram setpoint. The runback on loss of a condensate pump is initiated in anticipation of the reduced feedwater pump suction pressure when only three of the four condensate pumps remain in operation.

The runback logic is enabled when reactor power exceeds the capability of two feedwater pumps, as measured by total steam flow. A runback is initiated when less than three feedwater pumps are running and reactor water level drops below the low level alarm setpoint, or when less than four condensate pumps are running and total feedwater flow exceeds the capacity of two feedwater pumps. The runback will rapidly reduce core flow to approximately 70% of rated core flow, which is equivalent to 82% of uprated thermal power on the highest rod line. This feature will not alter the response characteristics of the reactor recirculation speed control system under normal operating conditions.

Proper operation of the runback logic will be verified in a post modification functional test. The feedwater control system response will be verified at various power levels. These tests will be used to confirm the runback dynamic analysis.

Reactor Feedwater Pump Low Suction Pressure Trip Logic

Since EPU conditions require the operation of three feedwater and four condensate pumps, there is an increased potential for low feedwater pump suction pressure in the event of a condensate pump trip. Both stations currently have feedwater pump protection logic for low suction pressure conditions. For EPU, this logic will be modified to stagger the feedwater pump trips consistent with three pump operation. The revised logic will trip one feedwater pump if suction pressure decreases to the low suction pressure trip setpoint for 3 to 5 seconds, then trip a second pump if suction pressure remains below this setpoint for 12 to 15 seconds. The remaining feedwater pump will not trip until suction pressure decreases to the low-low suction pressure trip setpoint. All pumps will continue to trip immediately if suction pressure decreases below the low-low suction pressure trip setpoint. Proper operation of the feedwater pump low suction pressure trip logic will be verified in a post modification functional test.

Scaling of Feedwater Control and Indication Loops

To accommodate the increased flow rates, the scaling of steam and feedwater flow loops will be increased to 3.5 million pounds mass per hour (Mlb/hr) for each steam line, 7 Mlb/hr for each feedwater pump, and 14 Mlb/hr each for total steam and feedwater flow. The feedwater pump runout (i.e., maximum feedwater flow) logic will also be revised to accommodate three pump operation. In addition to normal loop calibration and functional testing, the dynamic response of the control system will be verified by incremental step changes at various power levels. Feedwater flow indication will be verified at 90 % and 100 % rated thermal power (RTP) using installed ultrasonic flow devices. Feedwater pump performance will be monitored at various power levels to confirm runout protection requirements. Steam flow will be verified against feewater flow.

Question

2. Provide additional discussion of the effect of the EPU on the feedwater system, including your plans for handling additional flow in the system including heater drains. Are the line and valve sizing and system characteristics adequate for EPU conditions or are changes required? The regulatory concern is challenges to operators and safety systems caused by loss of feedwater heater strings and challenges to fuel integrity caused by the transients associated with loss of feedwater heating.

Response

The results of the EPU performance assessments of the balance of plant main thermal-hydraulic power cycle systems (i.e., feedwater, condensate, and heater drain valves), including consideration of the effect of the actual material conditions, indicate that the design capacity of these systems is sufficient to permit operation at EPU conditions. The thermal-hydraulic power cycle systems do not present a significant risk of additional feedwater transients as a result of EPU.

Evaluation of the feedwater heater drain system piping, valves, and instruments was performed at the pressures and temperatures expected at EPU conditions, assuming the turbine control valves were fully open. Reviews of the feedwater heater level control valve (LCV) and drain valve flows required for a range of uprated power levels were performed and compared to their flow passing capabilities. These reviews determined that the EPU operating conditions do not significantly challenge the inherent flow passing capabilities of the LCVs, with the exception of the DNPS Units 2 and 3 feedwater heater "B" normal LCVs. Further evaluations confirmed that trim replacement for these DNPS LCVs is required. These trim replacements will be implemented during each of the DNPS EPU refueling outages. QCNPS previously made similar changes to these valves and thus does not require this modification. Therefore, the system design will be adequate to prevent additional loss of feedwater transients.

The feedwater heater vessels were evaluated at EPU flows, pressures, and temperatures. With the planned shell modifications to re-rate the "C" and "D" feedwater heaters for increased pressures described in the Attachment G of the PUSAR, these vessels will be adequate to support operation at EPU conditions.

Therefore, based upon the above evaluations, additional challenges to operators, safety systems, and fuel integrity are not expected as a result of operation at EPU conditions.

Question
3. State the re-rated conditions for the feedwater heaters.

Response
The re-rated conditions for the feedwater heaters are provided in Figure 1.

Question
4. With the proposed modifications to the steam dryers, will the moisture carryover remain within the original design bases following EPU? If not, what reviews have been conducted to evaluate the increased moisture carryover?

Response
Review and analysis of current moisture carryover data, and the potential impact of EPU on moisture carryover, determined the need for a modification to the present steam dryer assemblies. The design criteria for the modification was to maintain carryover ≤ 0.2 wt% under most normal operating conditions, which is equivalent to the original startup test acceptance criteria. This design criteria was established based upon actual moisture carryover data collected from both the Dresden and Quad Cities Stations. Physical testing of the modified steam dryer assemblies confirmed the carryover fraction to be consistent with the modification design criteria.

Question
5. You have requested a significant increase in the magnitude of a main steam line break that will not be isolable automatically by the main steam isolation signal. You requested to raise the main steam isolation flow from 120% pre-EPU to 125% post-EPU for Dresden Unit 2; 120% pre-EPU to 140% post-EPU for Dresden Unit 3; and 138% pre-EPU to 254.3 psid for Quad Cities. The stated basis in NEDC-32424P-A for the increased magnitude of a main steam line break is to keep the same basis (expressed as a percentage of steam flow) to assure that reactor trip avoidance is maintained. For Dresden and Quad Cities, with a 17% power uprate, this

corresponds to an increase of 20% flow if the same percentage of steam line flow were maintained as addressed in the topical report.

What analyses have been performed for the safety impact (e.g., on core damage frequency or on high energy line break (HELB) analyses) of this additional range of steam line breaks (beyond the increase addressed in the EPU topical report), that is no longer automatically isolable? Provide the basis for the additional requested steam line break flow.

Response

The ELTR (Reference 2), Section F.4.2.5, "MSIV Closure on High Steam Flow Setpoint," states, "The setpoint for initiation of MSIV closure on high steam flow shall be raised to be equivalent to $\leq$ 140% of the uprated steam flow in each steamline." The proposed DNPS and QCNPS setpoints are all within the topical report setpoint.

The HELB analyses performed for EPU for main steam line breaks identified no additional impact due to EPU. The bounding steam line break is a complete rupture that results in choked flow through the flow restrictor. Since system pressure is not changed under EPU conditions, mass releases from such breaks are the same as before EPU. Since the mass releases are unchanged, there is no additional impact on the reactor core or on structures, systems, or components due to EPU.

For main steam line breaks resulting in less flow than the high flow setpoint, two diverse isolation signals will isolate postulated breaks. In RUN mode, low steam line pressure will result in isolation for breaks large enough to depressurize the steam line. Breaks that pass from 120%-140% flow will result in the low pressure isolation signal. These breaks are therefore still automatically isolable following EPU, regardless of location. In addition, postulated breaks in the main steam tunnel would actuate the area high temperature switches and result in isolation. Operability of both of these isolation signals is governed by the DNPS and QCNPS Technical Specifications (TS).

Question

6. Provide short term and long term results (curves or tables of calculated values as a function of time) of calculations for

- *drywell short term pressure and temperature*
- *suppression pool short term temperature*
- *wetwell atmosphere short term pressure and temperature*
- *suppression pool long term temperature*
- *wetwell atmosphere long term pressure and temperature*

If the long term calculation results are different from those used for calculating NPSH, provide the suppression pool long term temperature and wetwell atmosphere long term pressure and temperature used for the NPSH calculation.

Response
Drywell short term pressure and temperature are provided in Figures 2 and 3. Suppression pool short term temperature is provided in Figure 3. Wetwell atmosphere short term pressure and temperature are provided in Figures 2 and 3. Suppression pool long term temperature is provided in Figures 5 and 9. Wetwell atmosphere long term pressure and temperature are provided in Figures 4,5,8, and 9. Notes for the figures are provided in Table 1.

Figures 6,7,10, and 11 provide the curves showing the wetwell atmosphere pressure and temperature and the suppression pool temperature used for the net positive suction head (NPSH) calculation. As noted in Table 1, appropriate assumptions were used to minimize the containment pressure available and maximize the required NPSH.

Question
7. For Quad Cities, provide additional detail of the confirmatory calculations validating the SHEX computer code (ELTR1 SER Section 2.6(a)).

Response
Case E of the QCNPS UFSAR Table 6.2-3 was selected as a benchmark case to validate the SHEX computer code. This benchmark case was analyzed with SHEX, using input assumptions, which best represent the case. Case E assumed an instantaneous double-ended break of a reactor recirculation suction line (DBA-LOCA). It was assumed that one RHR loop equipped with one RHR pump and one service water pump is available. The input assumptions used in the benchmark analysis were not necessarily the same as those used for the EPU analysis. For instance, feedwater addition, which would result in higher peak pool temperature, was included in the EPU analysis, whereas the benchmark analysis ignored its effect. The following table provides key input assumptions used in the benchmark analysis.

Parameter	Value	Remarks
Decay heat	May-Witt	In the Long Term Program (LTP) for Mark I containment, the May-Witt decay heat values were used. It was assumed that the same decay heat values had been used around 1969 in the absence of information on the decay heat values used in the UFSAR analysis.
Feedwater addition	None	It is believed that feedwater addition was ignored in the original UFSAR analysis, since there is no mention about that in the UFSAR. Feedwater addition would result in a higher peak pool temperature.
Initial pool temperature	90°F	Based on plots.
RHR heat	276.1	The K-value is defined as total heat removal

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Parameter	Value	Remarks
exchanger K-value	Btu/sec-°F	rate (Btu/sec) divided by the heat exchanger inlet temperature difference. The K-value was obtained from process diagram.
Service water temperature	95°F	Obtained from process diagram. For typical analyses, the service water temperature is assumed to be the same as or lower than pool temperature.

Thus, the benchmark case (Case E of UFSAR Table 6.2-3) was analyzed with SHEX, and the peak pool temperature from the SHEX run was 181°F, which is 4°F higher than the 177°F reported in the UFSAR. This benchmark calculation, though based on limited information on the UFSAR analysis assumptions, shows that the SHEX prediction is representative, compared with the UFSAR analysis.

Question
8. Dresden proposed Technical Specification bases section B 3.6.1.4 is changed to reflect a reduced calculated peak drywell pressure of 43.9 psig for the limiting event. Additionally, the listed reference is changed to Updated Final Safety Analysis Report (UFSAR) Section 6.2.1.3, which was not provided in the application. Provide the referenced UFSAR Section or a draft of the section if it has not been revised for the EPU uprate.

Response
The proposed UFSAR Section 6.2.1.3, "Design Evaluation," is currently in draft form and is provided as Attachment B for both DNPS and QCNPS, for information only.

Question
12. Section 4.7 on post-LOCA combustible gas control notes margin changes in various parameters associated with the EPU and additional impact of GE14 fuel introduction on metal-water hydrogen production. Provide long term results (curves or tables of calculated values as a function of time) of calculations for

- *hydrogen and oxygen production*
- *hydrogen and oxygen concentrations*
- *nitrogen containment atmosphere dilution system nitrogen cumulative usage and capacity*
- *containment pressure buildup demonstrating meeting the 30-day acceptance limit.*

Response
Hydrogen production is provided in Figure 12. Oxygen production is not specifically presented, but equals one half of the hydrogen production.

Hydrogen and oxygen concentrations in primary containment without the use of the nitrogen containment atmosphere dilution (NCAD) system are provided in Figure 13.

Hydrogen and oxygen concentrations with the use of the NCAD system are provided in Figure 14.

NCAD system nitrogen cumulative usage is provided in Figure 15. The NCAD nitrogen storage system has a minimum volume of 200,000 scf as discussed in PUSAR Section 4.7, "Post-LOCA Combustible Gas Control."

Containment pressure buildup demonstrating meeting the 30-day acceptance limit of 50% of design pressure is provided in Figure 16.

Question

15. What effect, if any, does the EPU have on the service water system heat loads for the HPCI and LPCI room coolers?

Response

DNPS ECCS room cooler equipment consists of coolers for the LPCI/CS rooms and the HPCI room. QCNPS ECCS room cooler equipment consists of coolers for the RHR rooms and the HPCI room.

Under normal operating conditions, EPU has no effect on HPCI and LPCI room coolers.

After a design basis LOCA, the EPU suppression pool temperature will be higher than the pre-EPU pool temperature. Thus, EPU affects the RHR and LPCI/CS pump rooms since the pumps and the heat exchangers in these rooms process the higher temperature water from the suppression pool during emergency operation. This will increase the piping and heat exchanger heat loads to the rooms. The electrical heat load in ECCS rooms is not affected by EPU.

The QCNPS RHR corner room service water heat load will increase from 319,798 BTU/hr to 335,800 BTU/hr due to the higher EPU suppression pool temperature. The RHR corner room cooler capacity is 570,000 BTU/hr, which is greater than the EPU heat load. Therefore, the design LOCA room temperature of 150°F is not affected by EPU.

The DNPS LPCI/CS room service water heat load also increases due to EPU. However, no credit is given to the DNPS LPCI/CS corner room coolers for removal of the heat load. Under EPU post accident conditions, the peak room temperature is conservatively calculated to be 189° F without the use of the room coolers. The safety related components in these rooms have either been environmentally qualified to the higher temperatures or are being replaced with instruments that are environmentally qualified to the higher EPU post accident temperatures.

HPCI operation involving the suppression pool is not changed by EPU. Following a design basis LOCA, the reactor quickly depressurizes below the limit for HPCI operation. Therefore, HPCI is not credited and its components are not required to be environmentally qualified to the higher room temperatures resulting from a design basis LOCA.

HPCI room coolers are utilized to maintain the HPCI rooms as a mild environment during testing and for operation of the HPCI system during a small break LOCA. The maximum HPCI process temperature is unchanged for EPU, and is accommodated by the existing room coolers.

Question

17. Section 6.4.5 addresses the adequacy of the ultimate heat sink (UHS). In the event of downstream dam losses, the water trapped in the intake and discharge bay becomes the UHS for Quad Cities 1&2 and the water trapped in the intake canal becomes the UHS for Dresden 2&3. Considering the increased decay heat associated with the EPU, provide details of the analyses of the available water supply trapped in these UHSs for safe shutdown for all units; addressing conformance with Regulatory Guide 1.27. Include any revised timing of required operator actions to maintain the UHS; if any.

Response

The design basis for the DNPS and QCNPS Cities UHS was established prior to the issuance of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants." The design bases for the DNPS and QCNPS UHS are provided in UFSAR Section 9.2.5, "Ultimate Heat Sink," for each plant.

The capability of the UHS for operation at EPU conditions was evaluated within the context of the UHS design bases as stated above. The results are provided as follows.

QCNPS UHS Evaluation

At EPU conditions, with the use of the main condenser for 24 hours after shutdown, and the use of three portable pumps delivering 5100 gpm to the Residual Heat Exchanger Service Water (RHRSW) intake, the water in the suppression pool remains below the acceptance value of 177° F. The temperatures reached are 156° F prior to EPU and 166° F for EPU. The maximum cribhouse intake temperature remains below the acceptance value of 109° F. The temperatures reached are 106.5° F prior to EPU and 108° F for EPU for operation of one RHR pump and one RHRSW pump per unit.

Manual actions for placing and operating the portable diesel pumps in the event of a postulated failure of Lock and Dam No. 14 do not change as a result of EPU. The time available to position and operate the portable pumps to provide the makeup water from the river to the UHS is dependent only on the time to reach separation between the UHS and river (i.e., approximately two days) and is not affected by EPU operation.

DNPS UHS Evaluation

The response for the DNPS UHS evaluation will be provided separately.

Question

18. Section 7.1 Considering reactor power may now be limited by main generator capability, discuss implications of potentially load cycling the reactor due to environmental changes – such as diurnal heating and cooling effects changing cycle efficiency. Will this mode result in additional radioactive wastes being generated?

Response
The main generator will be limited to 912 megawatts-electric (MWe). Because of this limitation, and the change in plant efficiency over the course of an operating cycle, the thermal power of the reactor will generally be less than the rated thermal power of 2957 megawatts-thermal (MWth). It is expected that to maintain 912 Mwe during the coldest winter days, the reactor thermal power would be on the order of 2850 Mwth (i.e., approximately 96% of EPU RTP), while on the warmest summer days the reactor power would be expected to be near 2957 MWth (100% of EPU RTP). This 4% yearly variation in reactor power is easily achieved via a combination of changes in the operating control rod pattern and reactor core flow. These changes are very small over the time interval in which they occur. On a daily basis these changes due to plant efficiency parameters do not approach the magnitude of reactor power changes required for surveillance testing and rod pattern adjustments.

Radioactive waste generated is primarily affected by an increase in conductivity and increase in the amount of feedwater flow as a result of operating at higher power level. The effect on the generation of radioactive wastes due to load following is negligible. The conductivity and feedwater flow and the radioactive waste generated will not increase beyond that determined for the operation of the reactors at the maximum EPU power level for an entire operating cycle.

Question
19. PUSAR Section 4.1.1.1.(b), Local Pool Temperature with RV plus SRV Discharge, notes that because these plants have quenchers no evaluation nor limit is necessary as long as steam ingestion into the ECCS suction is not a concern. The NRC approved elimination of the local temperature limit provided quenchers were at an elevation above the ECCS suction. Since Dresden and Quad Cities have quenchers and suction strainers located in the same bays; an evaluation of the behavior of the steam plumes from the quenchers, relative to the entrainment flow path to the ECCS strainers was performed. Provide the details of this evaluation demonstrating that steam ingestion is not a concern. Include a description of the units' ECCS suction elevation relative to the suction strainers.

Response
The NRC previously approved elimination of the local pool temperature limit at DNPS as noted in Reference 4. As part of EPU, it was decided to include elimination of the local pool temperature limit for QCNPS as well.

An evaluation of the likelihood of steam ingestion into the ECCS suction strainers during safety relief valve (SRV) actuation was performed for DNPS and QCNPS. The evaluation was performed at EPU conditions for the most limiting geometry from the two plant designs, which was a case where the suction strainer and t-quencher are in the same torus bay with the least physical separation. The evaluation used the conservative assumption that the suppression pool is locally saturated in the region around the SRV quenchers and ECCS suction strainers. The evaluation also conservatively assumed operation of all ECCS pumps simultaneously with full SRV discharge flow.

The conservative premise was that steam ingestion would be predicted if the quencher steam plume intersects any part of the ECCS suction strainer or the entrainment envelope surrounding the suction strainer. The size of the steam plume generated from an SRV quencher and the envelope of flow drawn into the suction strainers were quantified and evaluated for overlap, which could result in steam ingestion. The results of these evaluations show that the steam plume from the SRV quencher located closest to a suction strainer will not intersect either the suction strainer or the envelope of flow (i.e., the entrainment envelope) drawn into the strainer. Therefore, steam ingestion is not predicted.

Since steam ingestion is not predicted at EPU conditions for the most limiting geometry, it is concluded that steam ingestion will not occur at DNPS or QCNES.

The ECCS pump suctions are located approximately six feet below the torus penetration connecting the ECCS ring header to the suction strainers (centerline to centerline). The strainer itself extends approximately five feet vertically into the torus from the penetration.

Question
20. Section 7.1 Provide the results of the evaluation of low pressure turbine missile analyses. Did these reanalyses confirm the potential need to change turbine overspeed protection settings?

Response
A missile analysis was previously performed for the DNPS and QCNPS turbines in 1986. Based upon review of this missile analysis, the predominant stresses that could cause a LP rotor failure were attributed to the centrifugal loading with only a small thermal stress contribution. Since the geometry of the LP rotors and blading is not changing as a result of EPU, the centrifugal stresses also do not change, and the existing analysis remains valid.

The overspeed to limit of 120% of rated speed is the limit used during original design and is not changing for EPU. Because EPU increases steam flow, turbine overspeed protection settings were reviewed by the original equipment manufacturer (OEM). As a result of this review, the current trip settings will be reduced, as applicable, to preclude rotor train speeds in excess of 120% of rated speed in the unlikely event of a simultaneous full load rejection and failure of both control and intermediate valves. A change to the backup overspeed trip (BUOT) setpoint in accordance with the OEM's recommendation is required at QCNPS Units 1 and 2. The current DNPS BUOT setpoint is within the range of the OEM recommendations and does not require revision.

Question
21. Section 7.1 notes that for the turbine-generator; valves, control systems and other support systems were evaluated for the effects of EPU. The results of the evaluation show that modifications to the high pressure turbine and some non-safety-related equipment should ensure satisfactory turbine-generator performance. Describe these modifications.

Response

Station	Modification Description
DNPS Units 2 and 3 QCNPS Units 1 and 2	Cross around relief valve (CARV) setpoint change – provide new relief pressure settings for all CARVs
DNPS Units 2 and 3 QCNPS Units 1 and 2	Replacement of HP turbine rotors and diaphragms – new HP boreless rotor and HP nozzle diaphragms for increased volumetric flows
DNPS Units 2 and 3 QCNPS Units 1 and 2	Stator water cooling alarm and runback setpoint changes - adjusted for revised flow conditions
DNPS Units 2 and 3 QCNPS Units 1 and 2	Electrohydraulic control / turbine supervisory instrumentation changes • Steam line resonance compensator – addition of 3rd harmonic filter • Diode function generator calibration – adjustment of control valve characteristic with increased steam flow • Turbine 1st stage pressure transmitter change – adjustment for new rated condition • Power load unbalance input span changes – adjustment of turbine intermediate pressure and generator current for new rated conditions • Differential expansion detector – change in detector calibration and alarm
DNPS Unit 2 and 3	Stator water cooling service water restriction orifices – increase heat removal capacity

Question

22. Section 8.2.1 addresses the impact of the EPU on the condenser off-gas system; noting an increase of (radiolytic) hydrogen flow from 26.3 to 30.9 lb$_m$ per hour under hydrogen water chemistry conditions. Additionally, the radioactive releases to be handled (held-up) by the off-gas system are estimated to increase proportionately to the power increase of 17%. Address how the combination of these proposed changes impact the design hold up times for the off-gas system; including the ability of the system to hold up a minimum of 30 minutes under conditions associated with 100 µCi/sec/Mwt release rates for noble gases; and (2) the operational impacts associated with the increase radiation shine effects caused by the increased feedwater hydrogen injection rates/main steam flow rates. As noted in Section 8.4.1.1, the impacts of hydrogen water chemistry on source terms are considered without credit for use of the effects of the NobleChem process, which considerably lowers the hydrogen feedwater injection requirements. Alternately, state if the use of NobleChem process to limit these effects is considered as part of the EPU basis.

Response

Holdup time in the offgas system, both in the delay line downstream of the recombiner and on the charcoal adsorbers, is affected only by main condenser air inleakage, and not by radiolytic hydrogen flow, which is removed in the offgas recombiner at the entrance to the system. Because EPU does not affect main condenser air inleakage, offgas system holdup times for noble gases are not affected by EPU. Therefore, an estimated increase in noble gas source term of 17% will result in a like increase in system release rate during periods of operation with significant fuel cladding leaks. However, because the current and expected fuel defect rate is extremely small, the actual offgas release rate is not expected to increase. Further, the maximum allowed release rate in the TS is not being changed for EPU.

As discussed in Reference 5, the calculated offsite dose due to turbine shine will increase in proportion to the uprate (i.e., 17%). This includes the effect of the increased hydrogen injection rate. However, the actual increase in turbine shine is expected to be less than the calculated increase. For a given feedwater hydrogen concentration, the increase in N-16 over baseline normal water chemistry conditions (i.e., no feedwater hydrogen) does not change for EPU. Therefore, the estimated 17% increase in N-16 due to EPU is offset by the approximately 19% increase in steaming rate (see PUSAR Sections 8.4.1 and 8.6), regardless of whether the plant is operating with or without hydrogen water chemistry (HWC) or NobleChem™. Under NobleChem™ operation, reduced feedwater hydrogen injection rates will significantly reduce the N-16 multiples resulting from HWC operation. Thus, for normal water chemistry operation and for HWC operation, offsite dose from turbine shine under EPU conditions will remain the same as current levels or will increase a small amount due to the small decrease in delay time in the steam lines from the increased steaming rate. For NobleChem™ application, turbine shine will decrease relative to levels prior to NobleChem™ application. Dose effects as presented in the EPU basis do not take credit for reduction due to NobleChem™, and therefore are bounding.

Question

23. Section 8.4.3 Clarify the statement in section 8.4.3 that the EPU does not change the design noble gas release rate from the fuel, specifically with respect to SRP 11.3 which provides guidance that the source term for noble gasses is a linear function of the power level and with respect to the stated original design bases of 0.2 Ci/sec after a thirty minute delay. Does the 0.2 Ci/sec original design basis bound the effect of a linear increase in power on the instantaneous off-gas limit noted in SRP 11.3?

Response

For the DNPS and QCNPS plants, the design basis is 0.2 Ci/s referenced to a 30 minute decay time. This design value was based upon past fuel performance at the time of original design (i.e., 1970 to 1972) and provided a margin of approximately a factor of two over the range in which these plants were expected to operate. Since that time period, improvements in fuel and operations have continually reduced the expected operating offgas values to small fractions of the original design basis. The expected offgas releases based upon current plant performance were estimated based on ANS Standard ANS/ANSI 18.1-1999 "Radiological Source for Normal Operation for Light Water Reactor," for the EPU condition. The results of this analysis show the offgas rate as evaluated by that standard to be a fraction of the original design basis. Therefore, the 0.2 Ci/sec design basis bounds the effect of the increase in power on the off-gas release rate.

Question

24. Section 8.4.3 Explain the stated expectation of no increase in fission product releases from the fuel as a result of EPU. Why won't the expected release rate increase in proportion to the reactor power level increase of 17%?

Response

To correct the statements in PUSAR Section 8.4.3, it is expected that some increase in fission product activity in reactor coolant will be seen. Using the formula in ANSI/ANS 18.1-1999, "Radiological Source Term for Normal Operation for Light Water Reactors," the increase would result in a calculated 12% increase in concentration. Even with this increase, the reactor coolant activity levels will be fractional parts of the design basis coolant concentrations.

Question

25. Section 10.1.1.1 addresses the main steam high energy line break and notes that the critical parameter affecting the HELB analyses is reactor dome pressure which is not being changed by the EPU. Do any of the HELB analyses credit isolation of the main steam lines to limit mass-energy released? If so, address the effects.

Response

The bounding main steam line break, a circumferential rupture that results in choked flow through the flow restrictor, credits isolation to limit the mass release. Since the steam pressure does not change due to EPU, the mass release from the limiting break is also unchanged. The DNPS and QCNPS UFSARs define the specific design basis break locations analyzed for HELB. All such postulated breaks in the main steam lines are located in the pipe tunnel. These breaks are isolated by any of three signals: the high steam line flow isolation, low steam line pressure isolation (in RUN mode), or high steam tunnel temperature isolation. Operability of all of these isolation signals are governed by the DNPS and QCNPS TS.

Question

26. Section 10.1.1.2 notes that for the EPU, the feedwater system line break results in a 6% increase in feedwater mass and energy release. The safety analysis further notes that design margins within the high energy line break analyses are conservative and remain bounding. Provide details of the main steam tunnel HELB analysis that addresses these margins, including major assumptions and results.

Response

The feedwater line break was used with a concurrent main steam line break to establish the peak pressure and the long term temperature environment in the main steam tunnel for DNPS and QCNPS.

(proprietary information removed)

The licensing design basis pressure for the main steam tunnel for DNPS and QCNPS is 27.5 psia. The main steam tunnel peak calculated pressure is 27.2 psia at 0.1 seconds.

(proprietary information reemoved)

Therefore, it can be concluded that the pre-EPU design basis main steam tunnel environmental parameters bound the EPU values for the feedwater HELB concurrent with a main steam line break.

Question

27. Section 10.2 notes that moderate energy line break protection features are based on system parameters unchanged by the EPU. Are portions of the condensate and feedwater system considered within the scope of this analyses? If so, has the additional flow associated with operation of four condensate pumps been evaluated? Are any changes in flow or system operation being proposed for the condenser circulating water system to accommodate increased heat load of EPU, or will the EPU otherwise impact the potential for flooding from a line break in this system?

Response

The condensate and feedwater systems are considered high energy systems. Postulated flooding from these systems is not within the scope of the moderate energy line break analysis, but was covered under flooding from high energy breaks.

Safety related equipment in the turbine building that could be subjected to the effects of flooding are the containment cooling service water (CCSW) pumps at DNPS and the RHR service water pumps at QCNPS. At DNPS, two of these pumps are located in watertight vaults. At QCNPS, all of the RHR service water pumps are located in watertight vaults. These passive protection features are designed to protect against the limiting event of a circulating water system rupture, which could flood the building to the level of the river. This flooding event bounds the consequences of a postulated condensate system rupture, regardless of the number of condensate pumps operating.

Feedwater system ruptures could affect safety-related equipment in the main steam tunnel due to flooding. The pre-EPU analysis of such ruptures assumed the tunnel would flood completely. This analysis therefore bounds the EPU case.

The circulating water system can accommodate the EPU heat load at the current system flow rate. The existing protective features for a circulating water system rupture include a trip of the pumps on high level in the condenser pit area. The ultimate consequences of such a rupture are due to subsequent gravity feed resulting in the flood water level reaching river level. Existing flood protection features are not affected by EPU.

Question
28. Section 11.3 notes that the quantity of spent fuel will not be affected by the uprate; although the short-term radioactivity will be higher but within limits. Please clarify this statement. Is there not an expectation that additional spent fuel assemblies will be required to support the 17% power increase; or is the entire power uprate accommodated in increased burn-up of fuel assemblies?

Response
This statement is incorrect. The statement on this issue in the Environmental Report (Attachment D to Reference 1), Section 3.3, "Radiological Environmental Impacts," is correct. The quantity of spent fuel discharged at the end of each uprated cycle will be larger than that discharged from the pre-EPU cycles.

Question
29. Is the capacity of the hardened vent sufficient to accommodate the power uprate?

Response
The design basis for the containment hardened vent is to mitigate loss of decay heat removal sequences, and to prevent further pressurization with the containment at its pressure limit. The vent was reanalyzed for EPU conditions to ensure this basis was still met.

For DNPS, the hardened vent will have a capacity of 1% of RTP after EPU. The QCNPS hardened vent will have a capacity of 0.85% of RTP after EPU. The EPU decay heat curve reaches 1% at 11,000 seconds, or 3.1 hours, and reaches 0.85% at 20,000 seconds, or 5.6 hours. Under EPU conditions, the containment will not reach the pressure limit until 20 hours after a loss of decay heat removal. The DNPS and QCNPS hardened vents are thus capable of relieving EPU decay heat with ample margin to the time when venting is required. Therefore, the existing DNPS and QCNPS hardened vent capacity is sufficient to accommodate the power uprate.

Question

30. The environmental qualification of non-metallic components, (i.e. seals, gaskets, lubricants, diaphragms, etc.) has not been addressed. Please demonstrate that plant operations at the proposed EPU level will have no impact on the environmental qualification of mechanical equipment located both inside and outside containment.

Response

Operating and environmental conditions are included in procurement specifications for such material.

Changes in operating conditions as well as normal and accident environmental conditions have been determined for EPU. These changes, as indicated in PUSAR Tables 4-1, "DBA-LOCA Containment Performance Results," 10-1, "High Energy Line Break," and 10-2, "Environmental Changes for Equipment Qualification and Affected Equipment Types," are very minor relative to the range of conditions normally allowed for such materials. The most severe change in conditions is due to the post LOCA increase in the torus water temperature. Due to the potentially higher fluid operating temperature of the Core Spray and LPCI pumps at DNPS only, which use process water for bearing cooling, the bearing lube oil is being changed for EPU. No other changes in materials of this type were identified for operation at EPU conditions.

Figure 1
Re-Rated Conditions for Feedwater Heaters

Feedwater Heater	**Design Conditions Pre-EPU**	**Design Conditions Post-EPU**
LP Drain Cooler A-2		
Design Pressure (PSIG)	50	50
Design Temperature (°F)	300	300
LP Heater #A1		
Design Pressure (PSIG)	50	50
Design Temperature (°F)	298	298
LP Heater B		
Design Pressure (PSIG)	50	50
Design Temperature (°F)	350	350
LP Heater C		
Design Pressure (PSIG)	75 (DNPS), 83 (QCNPS)	100
Design Temperature (°F)	350	350
HP Heater D		
Design Pressure (PSIG)	150	178
Design Temperature (°F)	450	450

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Table 1
Remarks on Figures 2 - 11

2 & 3	Pressure and temperature response from short term DBA-LOCA analysis	Break flow rate and enthalpy are calculated with LAMB (with Moody's slip critical flow model), using the model representing both Dresden and Quad Cities, and these break flow values are used as input to the M3CPT code. The initial wetwell and suppression pool temperature was conservatively assumed to be 98°F, as compared with 95°F assumed in the long-term SHEX analysis. The initial drywell and wetwell pressure are assumed to be their maximum expected normal operating values. The peak drywell pressure for the current power, based on the current method, was predicted to be lower than the UFSAR value, but higher than the peak value obtained during the Long Term Program (LTP) for Mark I containment, as shown below. UFSAR Current Analysis LTP Dresden 47 psig 42.8 psig 41.2 psig Quad Cities 47 psig 42.8 psig 40.6 psig The difference between the original UFSAR analysis and the current analysis may be mainly due to differences in the blowdown flow rates, although the same critical flow model (Moody's slip model) was used for both analyses. Depending upon the vessel modeling that provides input conditions for the critical flow model, the blowdown values could be different. The UFSAR indicated that the DBA-LOCA blowdown values used in that analysis might be over-predicted, which would cause the over-prediction of peak drywell pressure. It is noted that the current method resulted in higher peak drywell pressure, compared to the LTP analysis that was reviewed and approved by the NRC. The LTP analysis used the vessel blowdown model built into the M3CPT code, as compared with the current analysis based on the LAMB blowdown model.
4 & 5	Dresden pressure and temperature response from long term DBA-LOCA analysis with direct pool cooling	The wetwell and suppression pool temperature was assumed to be 95°F. The initial drywell and wetwell pressure were assumed to be their maximum expected normal operating values. It was conservatively assumed that the suppression pool surface stays unperturbed. This assumption results in an unrealistically high wetwell temperature early in the event, because of compression effects, while allowing no mixing between the airspace and pool even during the blowdown phase. Only one RHR pump was assumed to be available to maximize the pool temperature response
6 & 7	Dresden pressure and	The wetwell and suppression pool temperature was assumed to be 95°F. The initial drywell

	temperature response from DBA-LOCA analysis for NPSH	and wetwell pressure were assumed to be their minimum expected values. Two cases, short-term and long-term, were analyzed using different assumptions regarding operation of LPCI/containment cooling pumps. The short-term case, which applies to the time period before 600 seconds, assumed that water from four LPCI pumps flows into the drywell through the break to minimize the pressure response. The long-term case (applying to the time period after 600 seconds) assumed that before 600 seconds two LPCI pumps are operating without dumping the water into the drywell, and at 600 seconds one of the two LPCI pumps is switched to containment spray, while turning off the other. This case will maximize the pool temperature response. For NPSH evaluations, the results for the short-term case are used for the time period before 600 seconds, and the long-term results are used for the time period after 600 seconds. Figures 5 and 6 show the combined results (short-term results before 600 seconds and long-term results after 600 seconds). Because of different assumptions between the two cases (before and after 600 seconds), Figures 5 and 6 exhibits sudden changes in the pressure and temperature response at 600 seconds. For instance, the wetwell pressure is approximately 20 psia (the short-term result) at 600 seconds as a result of low drywell pressure (due to high (4 pumps) LPCI flow into the drywell), which is followed by opening of wetwell-drywell vacuum breakers. Right after 600 seconds, the wetwell pressure is approximately 30 psia (the long-term results), because of the difference in the event scenario between the short-term and long-term cases.
8 & 9	Quad Cities pressure and temperature response for long term DBA-LOCA with direct pool cooling	Same assumptions as for the Dresden analysis, using Quad Cities RHR heat exchanger K-value of 262 Btu/sec-°F compared with 281.7 Btu/sec-°F for Dresden.
10 & 11	Quad Cities pressure and temperature response for DBA-LOCA for NPSH	Same assumptions as for the Dresden analysis, using Quad Cities RHR heat exchanger K-value of 262 Btu/sec-°F compared with 281.7 Btu/sec-°F for Dresden. As mentioned above for the Dresden analysis, two cases, short-term and long-term, were analyzed using different assumptions regarding operation of LPCI/RHR (containment cooling) pumps. The combined results (short-term results before 600 seconds and long-term results after 600 seconds) are plotted in Figures 9 and 10. Because of different event scenarios between the two cases, Figures 9 and 10 show sudden changes in the pressure and temperature response at 600 seconds.

Figure 2
Dresden and Quad Cities Short-Term DBA-LOCA
Containment Pressure Response

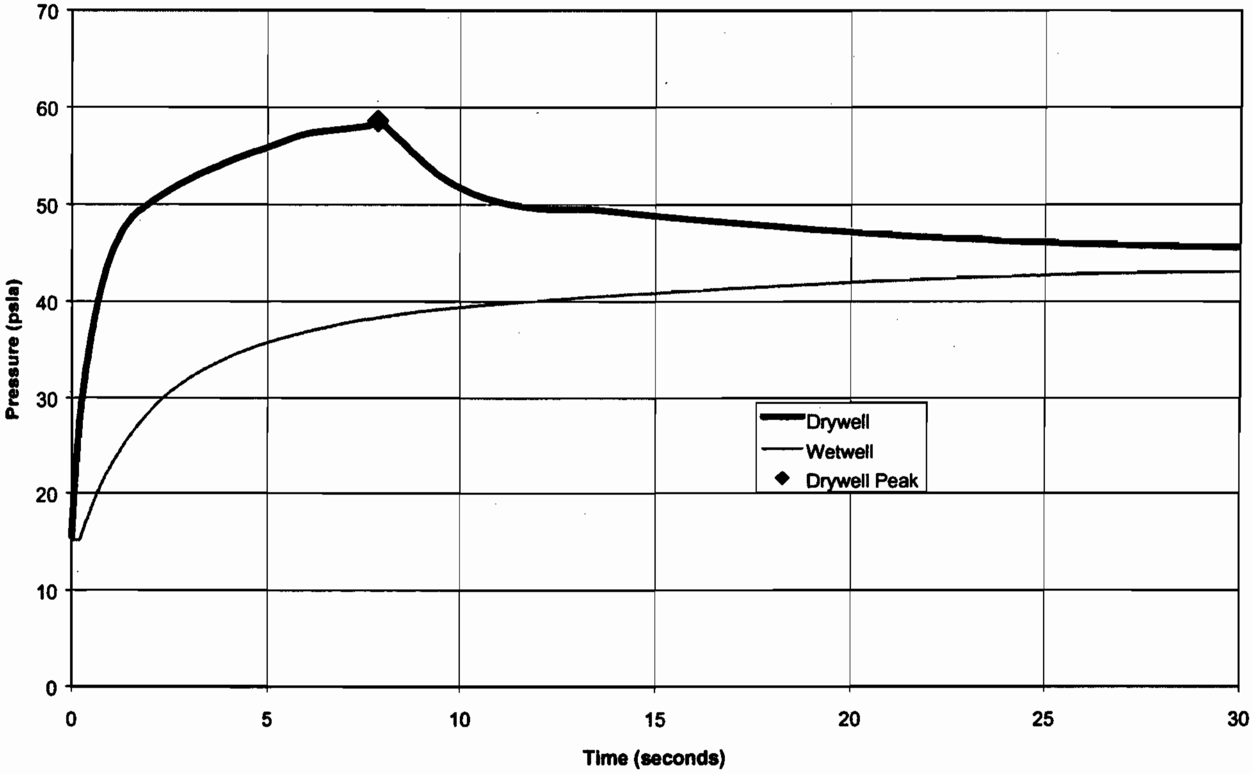

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Figure 3

Dresden and Quad Cities Short-Term DBA-LOCA Containment Temperature Response

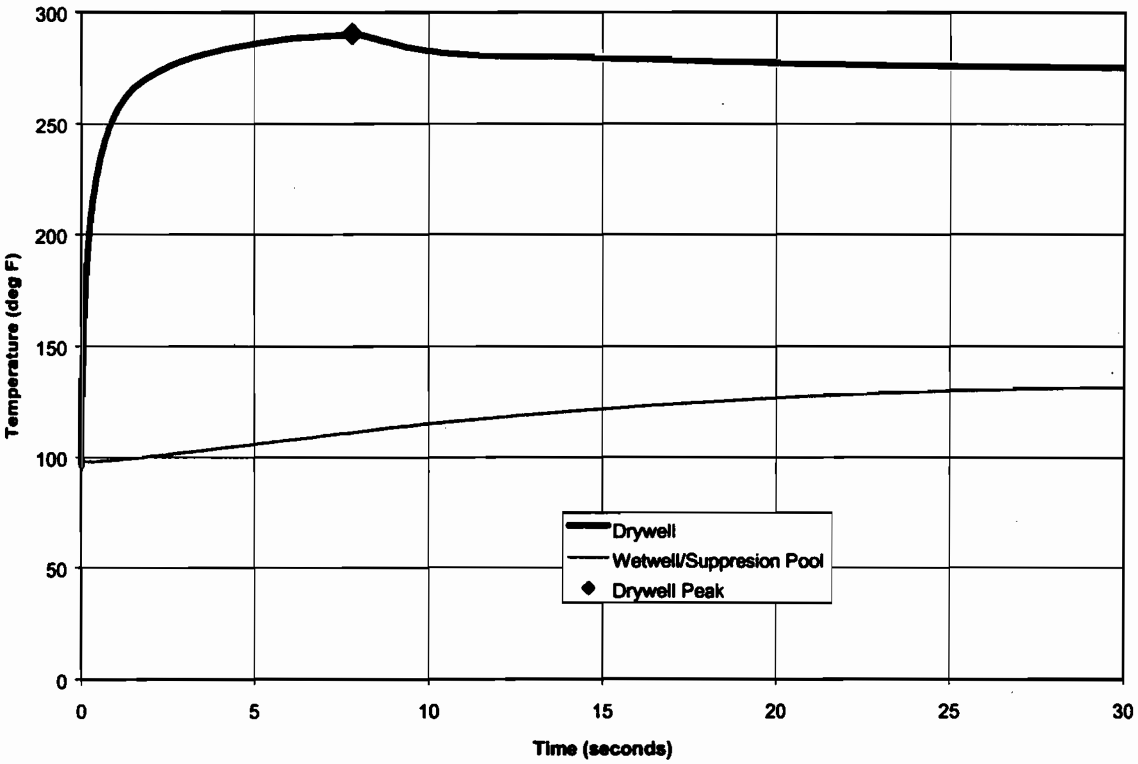

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Figure 4
Dresden DBA-LOCA with Direct Pool Cooling Containment Pressure Response

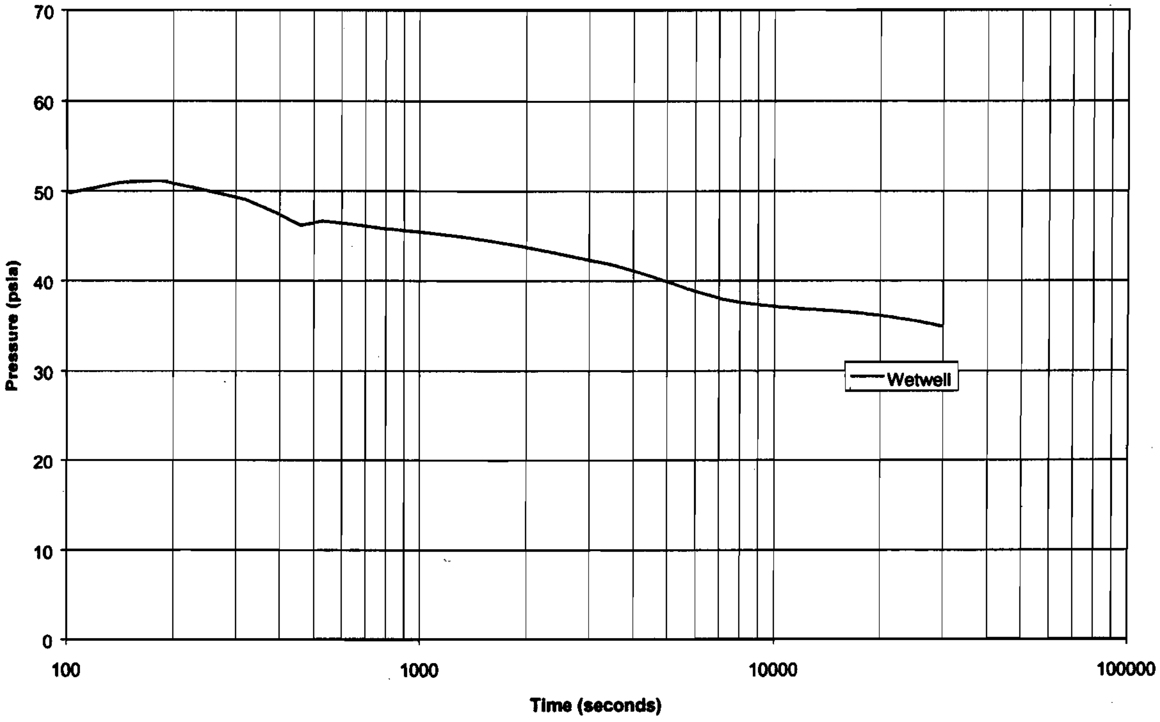

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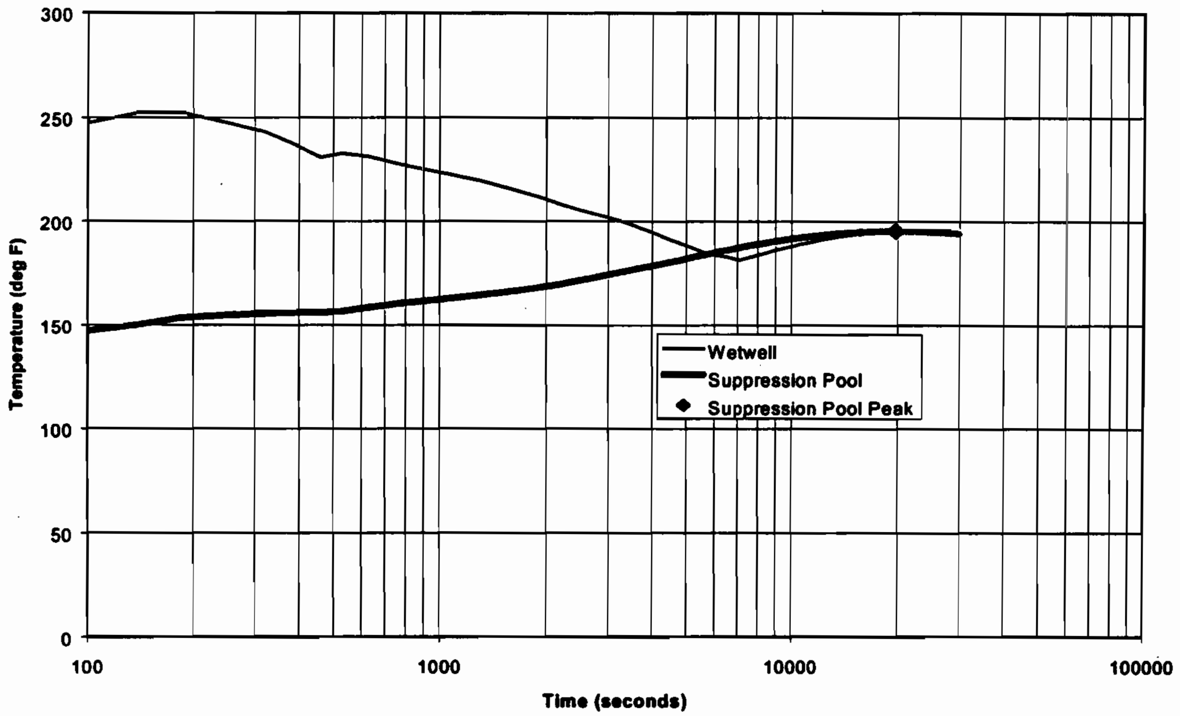
Figure 5
Dresden DBA-LOCA with Direct Pool Cooling
Containment Temperature Response



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Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
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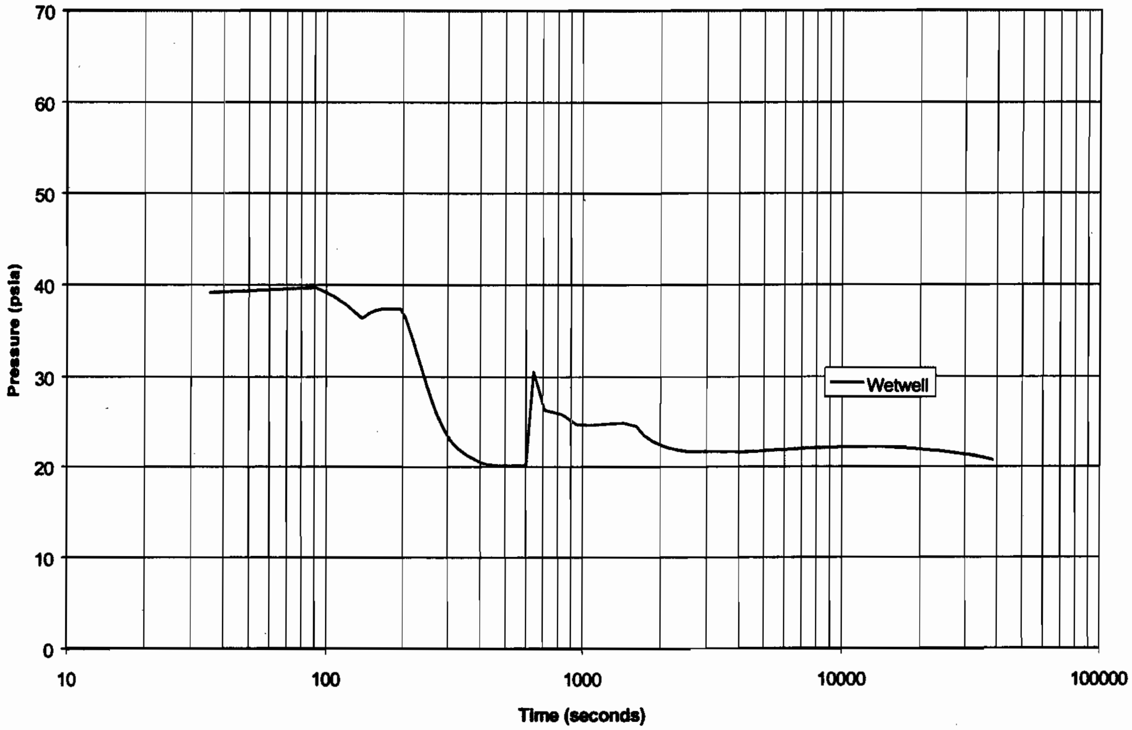
Figure 6
Dresden DBA-LOCA for NPSH
Containment Pressure Response



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Additional Plant Systems Information Supporting the License Amendment Request for Uprated Power Operation
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Figure 7
Dresden DBA-LOCA for NPSH
Containment Temperature Response

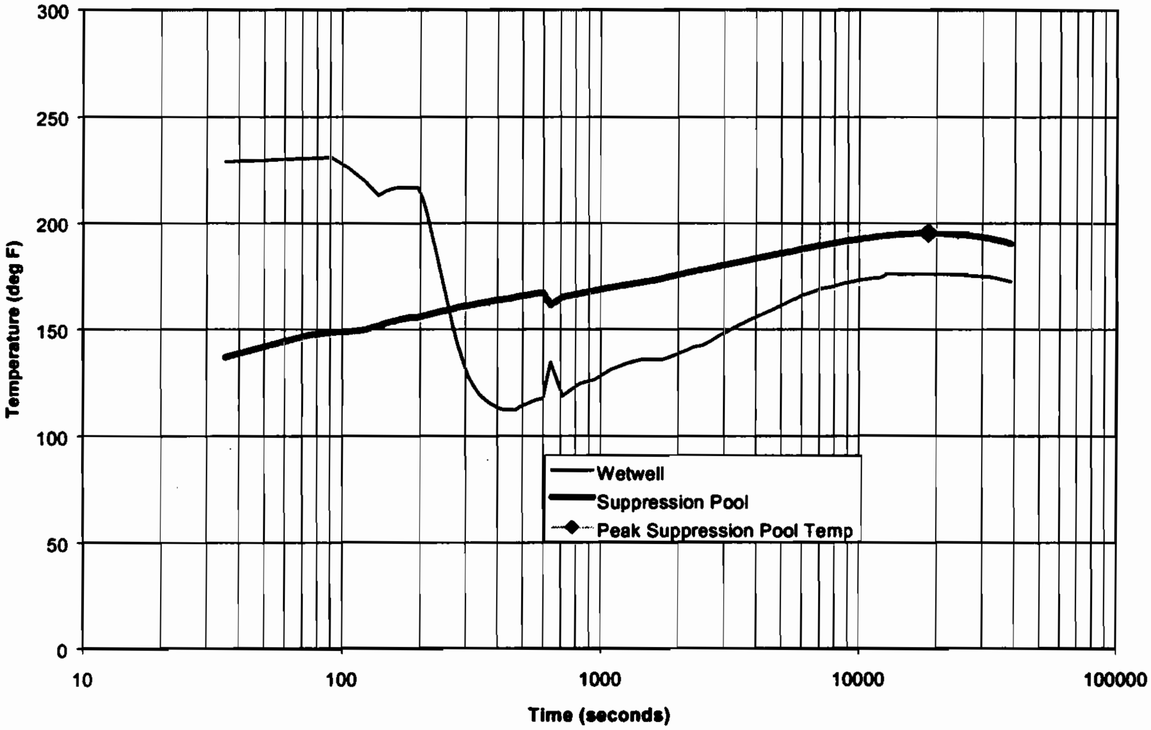

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Figure 8
Quad Cities DBA-LOCA with Direct Pool Cooling Containment Pressure Response

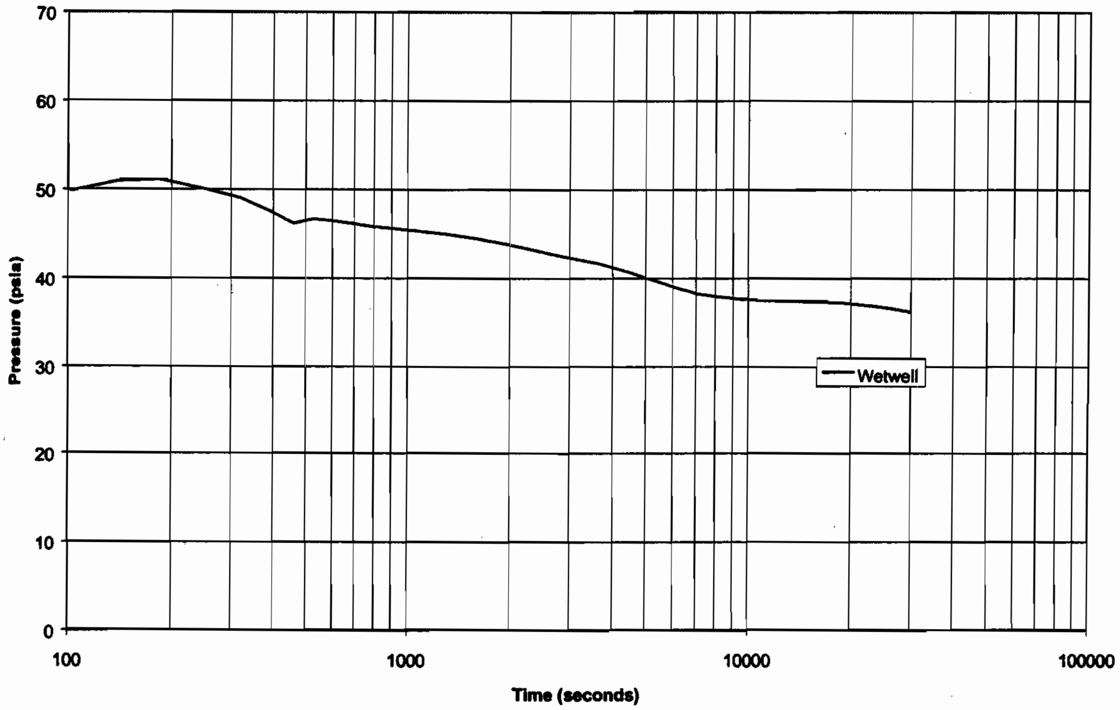

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Figure 9
Quad Cities DBA-LOCA with Direct Pool Cooling
Containment Temperature Response

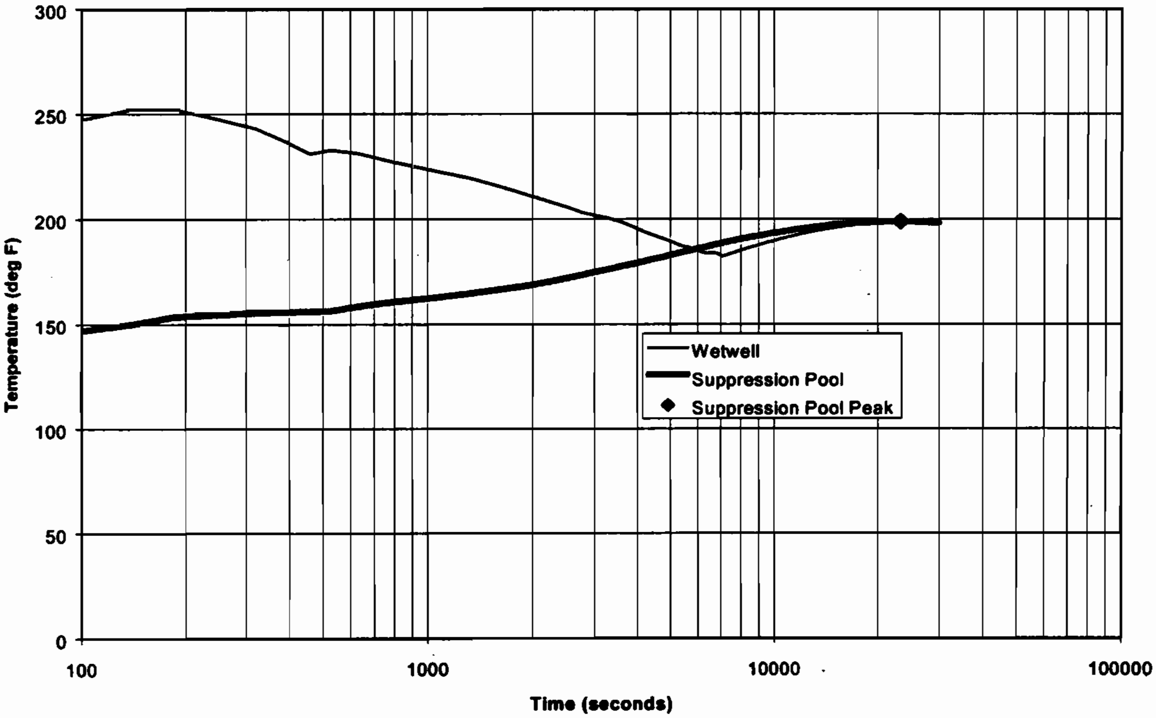

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Figure 10
Quad Cities DBA-LOCA for NPSH
Containment Pressure Response

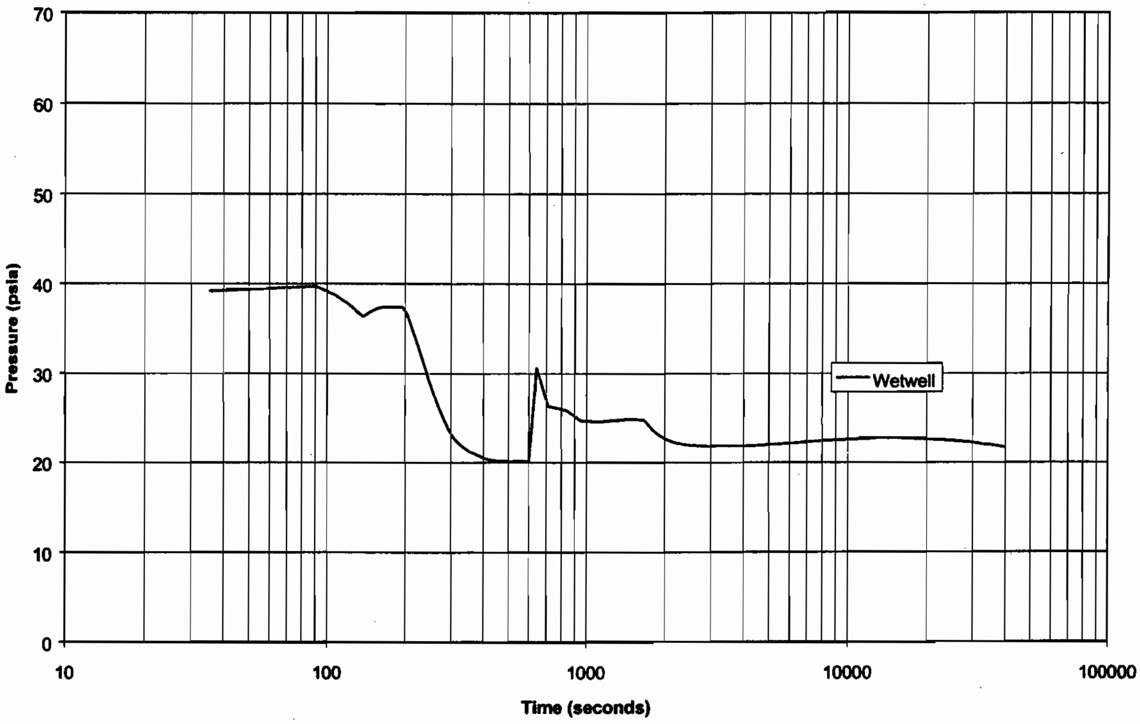

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Figure 11
Quad Cities DBA-LOCA for NPSH
Containment Temperature Response

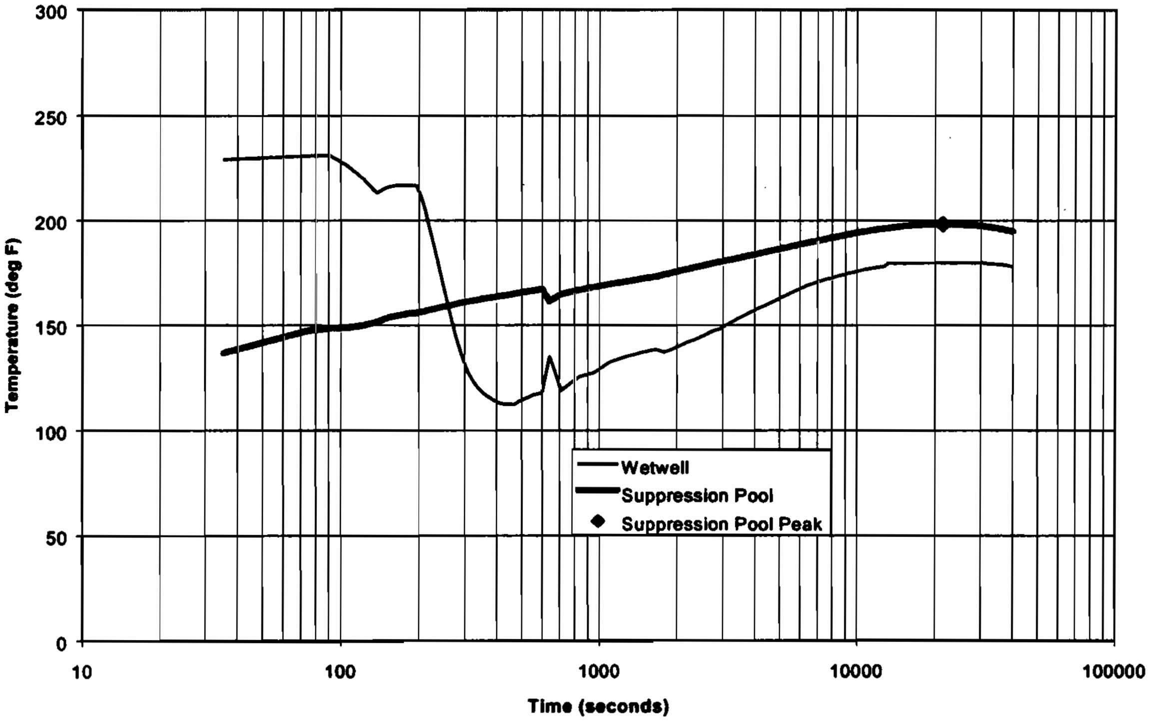

Figure 12
Hydrogen Generation Rate in Containment Following Loss of Coolant Accident

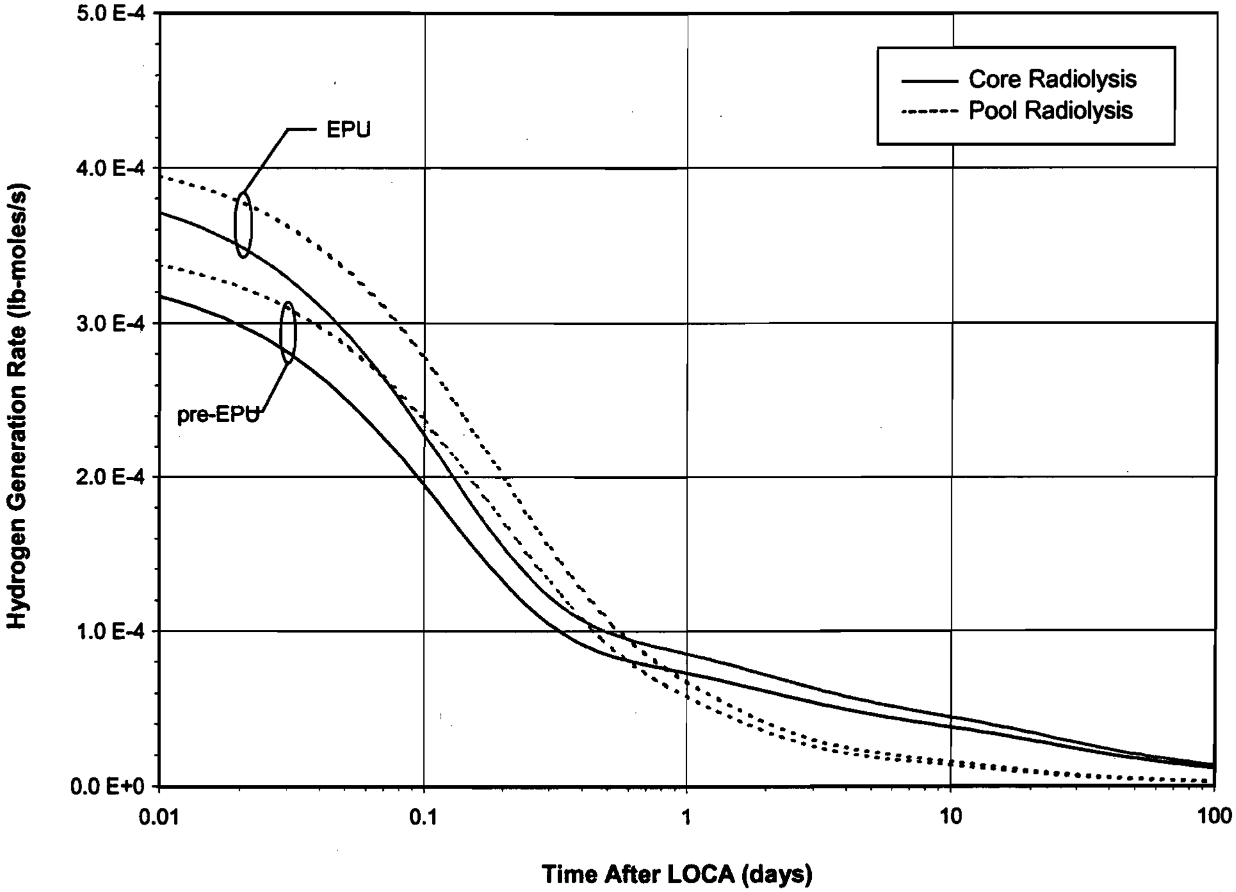

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Figure 13

Containment Hydrogen and Oxygen Concentrations Without Nitrogen Containment Atmosphere Dilution System

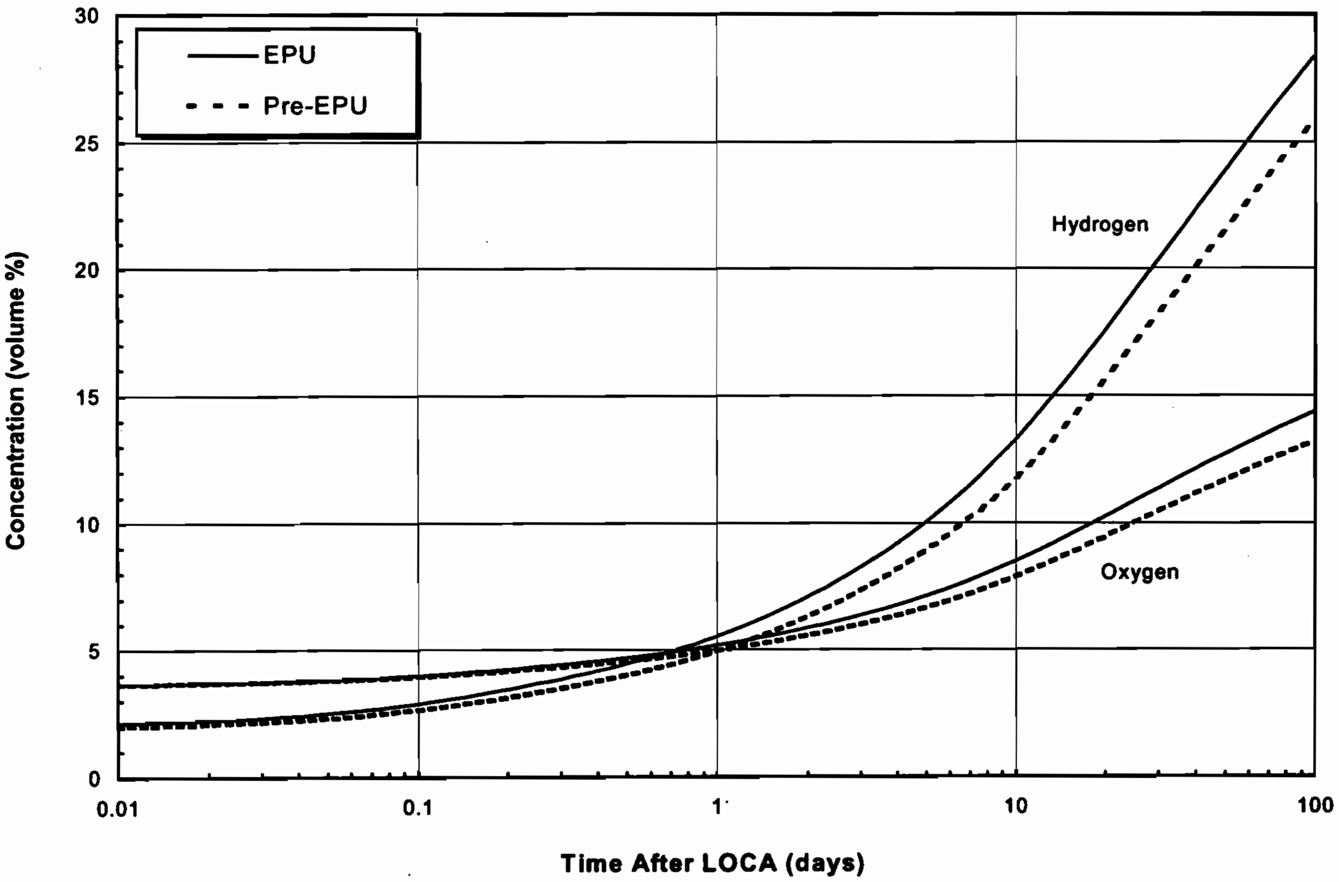

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Figure 14

Containment Hydrogen and Oxygen Concentrations
With Nitrogen Containment Atmosphere Dilution System Operation

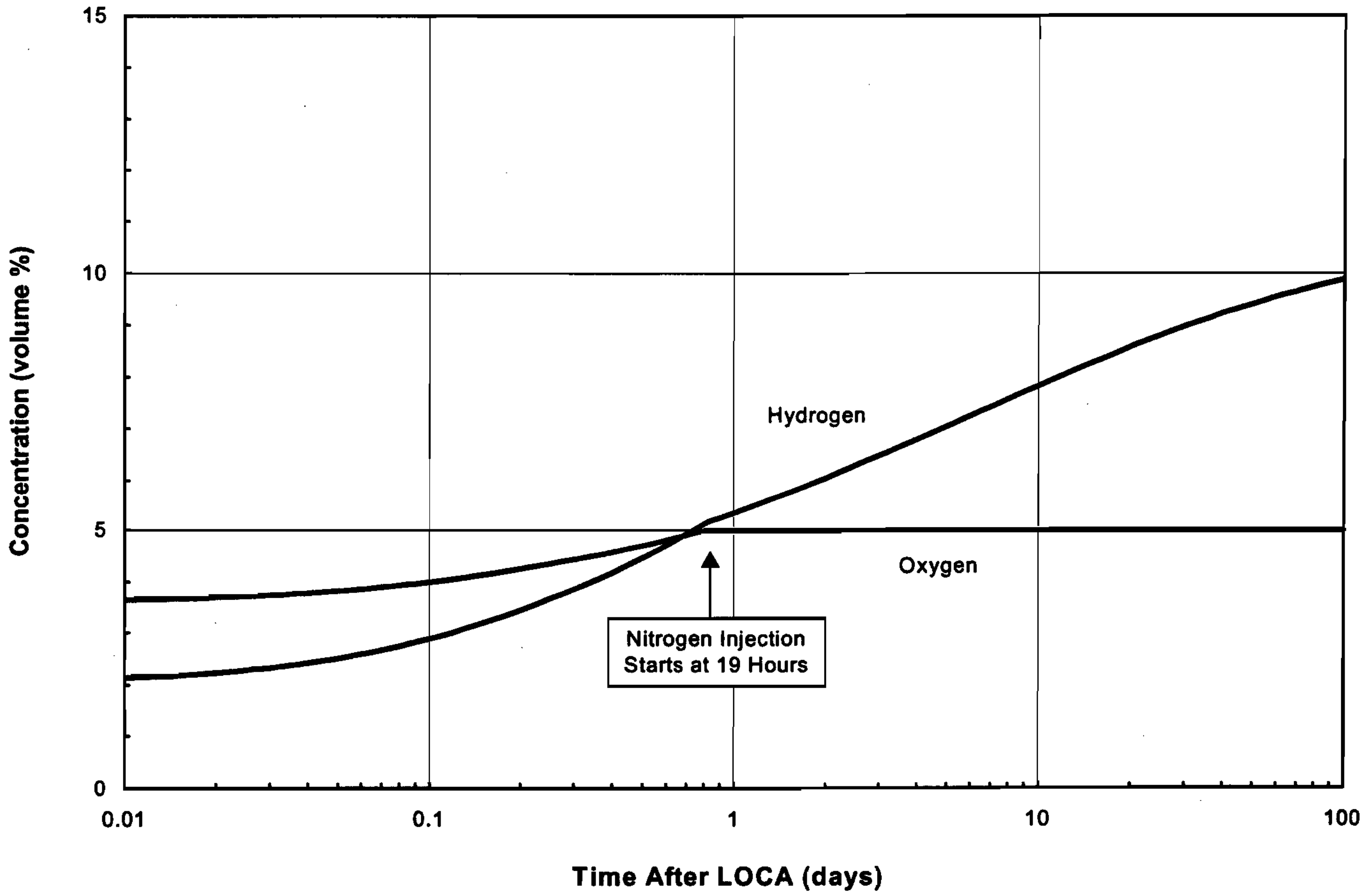

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Figure 15
NCAD System Nitrogen Cumulative Usage

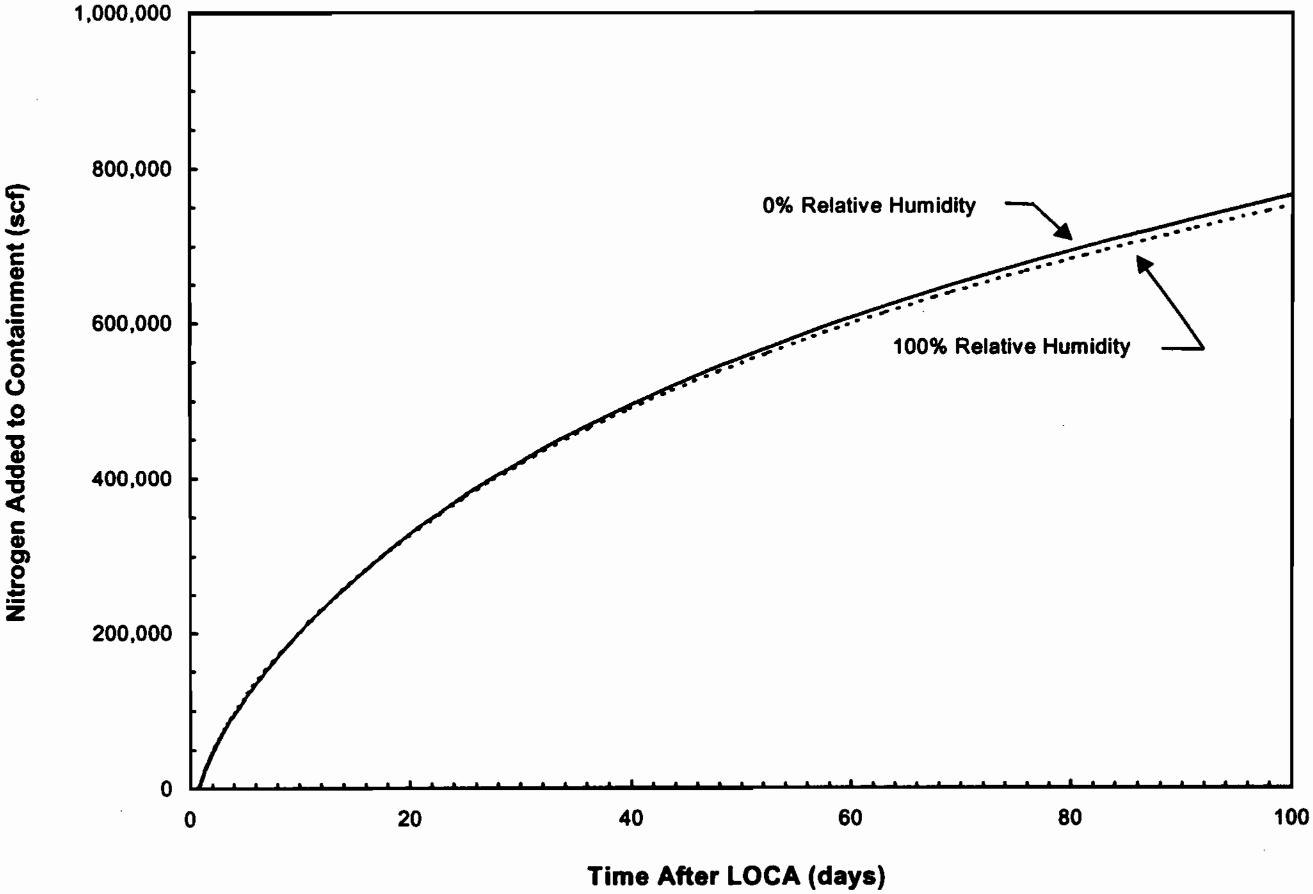

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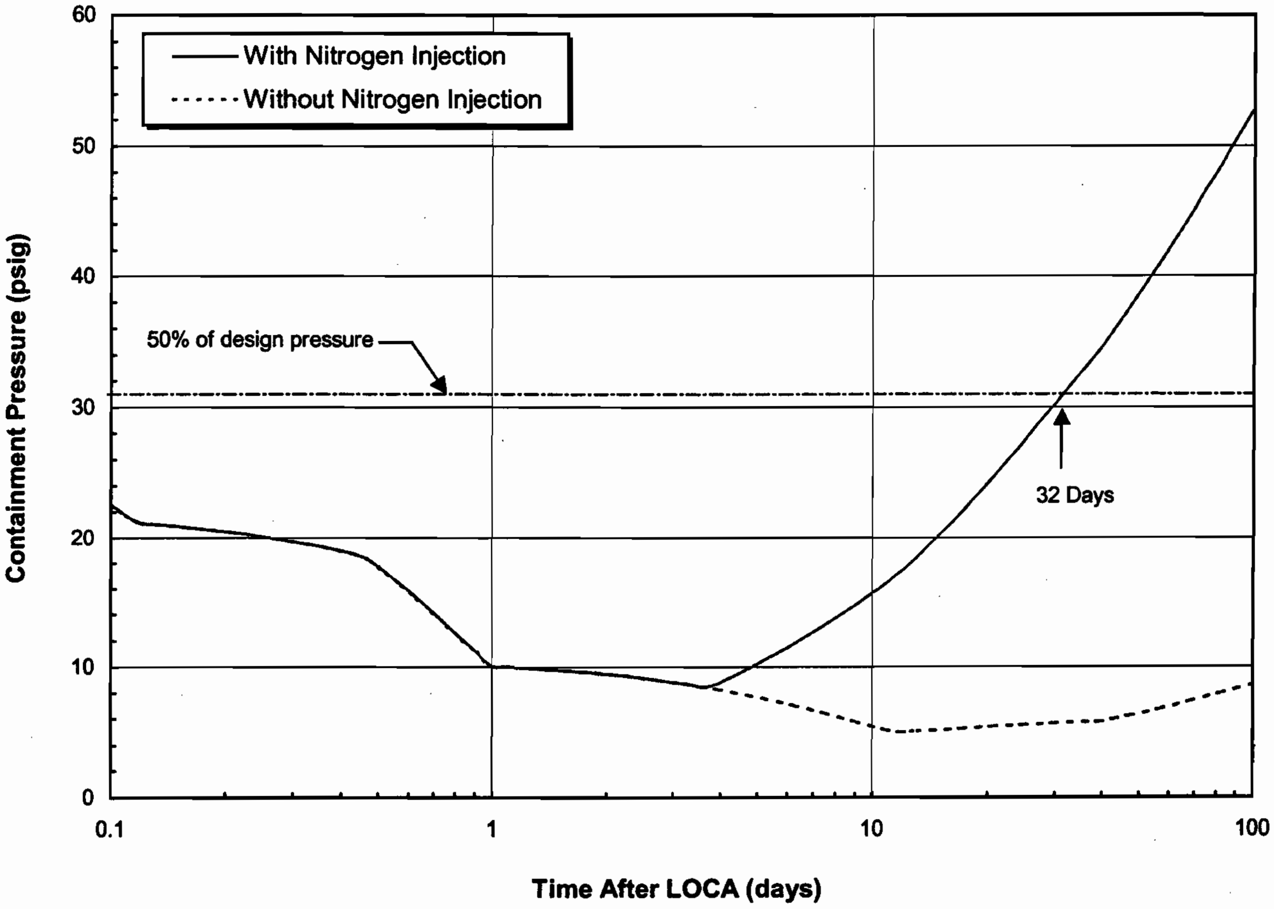
Figure 16
Containment Pressure Response to
Nitrogen Containment Atmosphere Dilution System Operation



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References

1. Letter from R. M. Krich (Commonwealth Edison Company) to U. S. NRC, "Request for License Amendment for Power Uprate Operation," dated December 27, 2000

2. Licensing Topical Report, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32424P-A, Class III, February 1999

3. Letter from U. S. NRC to G.L. Sozzi (General Electric), "Staff Position Concerning General Electric Boiling-Water Reactor Extended Power Uprate Program," dated February 8, 1996

4. Letter from U. S. NRC to I. Johnson (Commonwealth Edison Company), "Issuance of Amendments," dated April 30, 1997

5. Letter from R. M. Krich (Exelon Generation Company, LLC) to U. S. NRC, "Additional Health Physics Information Supporting the License Amendment Request to Permit Uprated Power Operation at Dresden Nuclear Power Station and Quad Cities Nuclear Power Station," dated May 29, 2000