ENCLOSURE 2

MFN 08-012

NEDO-33075-A - Non-proprietary

Non-Proprietary Version

IMPORTANT NOTICE

This is a non-proprietary version of Enclosure 1 to MFN 08-012, from which the proprietary information has been removed. Portions of the enclosure that have been removed are indicated by an open and closed bracket as shown here [[ ]]. Note the NRC's Final Safety Evaluation is enclosed in NEDO-33075-A, Rev. 6. Portions of the Safety Evaluation that have been removed are indicated with a single square bracket as shown here. [ ]

GE Nuclear Energy

175 Curtner Ave., San Jose, CA 95125

NEDO-33075-A, Revision 6
DRF-0000-0044-7571
Class I
January 2008

NON-PROPRIETARY VERSION

LICENSING TOPICAL REPORT

GENERAL ELECTRIC BOILING WATER REACTOR DETECT AND SUPPRESS SOLUTION – CONFIRMATION DENSITY

INFORMATION NOTICE

This is a non-proprietary version of the document NEDC-33075P, which has the proprietary information removed. Portions of the document that have been removed are indicated by an open and closed bracket as shown here [[ ]]. Note the NRC's Final Safety Evaluation is enclosed in NEDE-33147P-A, Rev. 2. Portions of the Safety Evaluation that have been removed are indicated with a single square bracket. GE has received US patent #6,173,026 covering this subject matter.

IMPORTANT NOTICE REGARDING CONTENTS OF THIS REPORT

PLEASE READ CAREFULLY

The information contained in this document is furnished for the purpose of obtaining NRC approval of the licensing requirements for implementation of the stability Detect and Suppress Solution – Confirmation Density (DSS-CD) to provide automatic detection and suppression of stability related power oscillations. The only undertakings of GEH with respect to information in this document are contained in contracts between GEH and participating utilities, and nothing contained in this document shall be construed as changing those contracts. The use of this information by anyone other than those participating entities and for any purposes other than those for which it is intended is not authorized; and with respect to any unauthorized use, GEH makes no representation or warranty, and assumes no liability as to the completeness, accuracy, or usefulness of the information contained in this document.

MFN-06-496

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

RECEIVED
DEC - 1 2006
GENERAL ELECTRIC COMPANY

November 27, 2006

Mr. Bob E. Brown
General Manager, Regulatory Affairs
GE Nuclear Energy
P. O. Box 780, M/C A-30
Wilmington, NC 28401

SUBJECT: FINAL SAFETY EVALUATION FOR GENERAL ELECTRIC NUCLEAR ENERGY (GENE) LICENSING TOPICAL REPORT (LTR) NEDC-33075P, REVISION 5, "GENERAL ELECTRIC BOILING WATER REACTOR DETECT AND SUPPRESS SOLUTION - CONFIRMATION DENSITY" (TAC NO. MC1737).

Dear Mr. Brown:

By letter dated July 24, 2002, and revisions dated January and August 2004 and December 2005, GENE submitted LTR NEDC-33075P, "General Electric Boiling Water Reactor Detect and Suppress Solution - Confirmation Density" to the U.S. Nuclear Regulatory Commission (NRC) staff. By letter dated July 13, 2006, NRC draft safety evaluations (SEs) regarding our approval of LTR NEDC-33075P, Revision 5, were provided for your review and comments. GENE commented on the draft SEs via e-mails dated August 14, 17, and 22, 2006. The NRC staff's disposition of GENE's comments on the draft SEs are discussed in Attachment 1 to the final SEs enclosed with this letter.

The NRC staff has found that LTR NEDC-33075P, Revision 5, is acceptable for referencing in licensing applications for GENE designed boiling water reactor/3 through /6 product lines using GE14 and earlier GE fuel designs to the extent specified and under the limitations delineated in the LTR and in the enclosed final SE. The final SE defines the basis for our acceptance of the LTR.

Our acceptance applies only to material provided in the subject LTR. We do not intend to repeat our review of the acceptable material described in the LTR. When the LTR appears as a reference in license applications, our review will ensure that the material presented applies to the specific plant involved. License amendment requests that deviate from this LTR will be subject to a plant-specific review in accordance with applicable review standards.

In accordance with the guidance provided on the NRC website, we request that GENE publish accepted proprietary and non-proprietary versions of this LTR within three months of receipt of this letter. The accepted versions shall incorporate this letter and the enclosed final SE after the title page. Also, they must contain historical review information, including NRC requests for additional information and your responses. The accepted versions shall include an "-A" (designating accepted) following the LTR identification symbol.

If future changes to the NRC's regulatory requirements affect the acceptability of this LTR, GENE and/or licensees referencing it will be expected to revise the LTR appropriately, or justify its continued applicability for subsequent referencing.

Sincerely,

Ho K. Nieh, Deputy Director
Division of Policy and Rulemaking
Office of Nuclear Reactor Regulation

Project No. 710

Enclosures: 1. Final Non-proprietary SE
2. Final Proprietary SE

cc w/encl 1 Only: See next page

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FINAL SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

GE NUCLEAR ENERGY LICENSING TOPICAL REPORT

NEDC-33075P, "GENERAL ELECTRIC BOILING WATER REACTOR DETECT AND SUPPRESS SOLUTION - CONFIRMATION DENSITY"

PROJECT NO. 710

1.0 INTRODUCTION

By letter dated July 24, 2002 (Reference 1), General Electric (GE) Nuclear Energy (GENE) requested U.S. Nuclear Regulatory Commission (NRC) review of licensing topical report (LTR), NEDC-33075P, "General Electric Boiling Water Reactor [BWR] Detect and Suppress Solution - Confirmation Density [(DSS-CD)]." During the course of the NRC staff review, GENE submitted revisions to the LTR, dated January and August 2004 and December 2005 (References 2, 3, and 4, respectively). The purpose of NEDC-33075P is to provide the licensing basis and methodology used to demonstrate the adequacy of the DSS-CD solution to reliably detect and suppress anticipated stability related power oscillations. This safety evaluation (SE) will provide a generic licensing basis for DSS-CD applications to GE BWR/3-6 product lines using GE14 and earlier GE fuel designs and an operating envelope up to and including extended power uprate (EPU) and maximum extended load line limit analysis plus (MELLLA+).

LTR NEDC-33075P describes a digital-based safety-related solution for detecting coupled neutronic/thermal-hydraulic instabilities in BWRs. The DSS-CD trip function identifies the beginning of power oscillations and generates a reactor trip signal before the oscillation amplitudes exceed the plant safety limit minimum critical power ratio (SLMCPR) for anticipated power oscillations. The LTR also provides a description of Backup Stability Protection (BSP) approaches that may be used when the DSS-CD licensing basis algorithm cannot be demonstrated to provide its intended SLMCPR protection. The BSP trip function provides a diverse means of preventing power oscillations from exceeding the SLMCPR. The LTR documents the design philosophy used in the development of the DSS-CD hardware/software, licensing basis, and required changes to the technical specifications (TS) and bases for the implementation of DSS-CD. The hardware design is unchanged from the Option III solution described in References 5, 6, and 7. The firmware/software is modified relative to Option III to reflect the specific DSS-CD stability detection methods, which may include an upgrade to the automatic signal processor card.

The NRC staff review includes the subject LTR and its revisions References 1 through 4), responses to the NRC staff's requests for additional information (RAIs) (References 8 through 10) and supporting information submitted by GENE (References 11 through 28). The NRC staff was assisted in its review by its consultant, Oak Ridge National Laboratory (ORNL), who wrote the technical evaluation report (TER). The review conducted by ORNL with the NRC staff's confirmatory calculations (Appendix A to the TER) indicated that the proposed methodology to define detect and suppress methodology is adequate and satisfies the requirement for an acceptable long-term stability (LTS) solution. The NRC staff has reviewed the TER and has adopted the findings recommended by ORNL.

2.0 REGULATORY EVALUATION

The DSS-CD design provides automatic detection and suppression of a reactor instability and minimizes reliance on the operator to suppress instability events. The Confirmation Density Algorithm (CDA) is designed to recognize an instability and initiate control rod insertion before the power oscillations increase much above the noise level. The DSS-CD solution and its related licensing basis were developed to comply with the requirements of General Design Criteria 10 and 12 in Part 50 of Title 10 of the *Code of Federal Regulations* (10 CFR), Appendix A, "General Design Criteria for Nuclear Power Plants."

Criterion 10, "Reactor design," requires that: "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 exceeded during any condition of normal operation, including the effects of anticipated operational occurrences."

Criterion 12, "Suppression of reactor power oscillations," requires that: "The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed."

To ensure compliance with Criteria 10 and 12, Appendix A, 10 CFR Part 50, the NRC staff will confirm that the licensee performs the plant-specific trip setpoint calculations using NRC-approved methodologies as prescribed in NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Chapter 4. The subject LTR provides the licensee's application to support its TS license amendment changes.

Appendix B to 10 CFR Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," establishes the minimum quality requirements for the design, fabrication, construction, and testing of structures, systems, and components of nuclear power plants and fuel reprocessing facilities. Nuclear power plants include the structures, systems, and components that prevent or mitigate the consequences of postulated accidents that could cause undue risk to the health and safety of the public. These requirements establish the criteria by which the NRC staff review the development of safety system hardware and software for use in nuclear power plants.

The GENE safety system development process has been approved by the NRC staff as a process that is consistent with the requirements of 10 CFR Part 50, Appendix B. The DSS-CD and BSP trip functions were developed for use in GE-design BWRs using the GENE safety system development process, thereby addressing the requirements of 10 CFR Part 50, Appendix B.

3.0 TECHNICAL EVALUATION

LTR NEDC-33075P, Revision 5, describes the methodology proposed by GENE to define the licensing basis and reload applications for the DSS-CD solution. The DSS-CD licensing basis consists of two major components: (a) an efficient oscillation detection algorithm - the CDA, providing an early trip signal upon instability inception prior to any significant oscillation amplitude growth and minimum critical power ratio (MCPR) degradation and (b) a set of GE proprietary integrated Transient Reactor Analysis Code (TRACG) event simulations for reasonably limiting anticipated events that confirm the limited effect on the MCPR performance within the stated applicability range. This SE evaluates component (a) of the DSS-CD solution. A separate SE will be issued to cover the TRACG component (b) of the evaluation.

3.1 Solution Design Concept and Description

The DSS-CD hardware design is unchanged from the Option III solution described in Reference 5. The firmware/software is modified relative to Option III to reflect the specific DSS-CD stability detection methods. The DSS-CD design provides automatic detection and suppression of reactor instability events to minimize reliance on the operator to suppress instability events. However, alarms are provided to alert the operator of an increase in the number of confirmed period counts so actions can be taken to avoid a reactor scram.

The basic input unit of the DSS-CD system is the oscillation power range monitor (OPRM) cell. The OPRM cell consists of one to eight closely spaced local power range monitor (LPRM) detectors. The signals from the individual LPRM detectors in a cell are averaged to produce the OPRM cell signal. For the DSS-CD solution the maximum number of LPRM detectors per OPRM cell is limited to four. The cell signal is filtered to remove noise components with frequencies above the range of stability related power oscillations. This is accomplished by a second order Butterworth filter with cutoff frequency of 1.0 Hz. This conditioned signal is filtered again using second order Butterworth filter with a shorter cutoff frequency of 1/6 Hz (or an equivalent time constant of 0.95 seconds) to produce a time-averaged value. The conditioned and time-averaged signals are used by the four algorithms to detect reactor instabilities. Each of the four independent OPRM channels consists of many OPRM cells distributed throughout the core so that each channel provides monitoring of the entire core.

The DSS-CD solution includes four separate algorithms for detecting stability related oscillations: CDA, Period Based Detection Algorithm (PBDA), Amplitude Based Algorithm (ABA), and Growth Rate Algorithm (GRA). The PBDA, ABA, and GRA detection algorithms provide the protection basis for LTS Option III (Reference 7). They are retained in DSS-CD as defense-in-depth algorithms and are not part of the licensing basis for the DSS-CD solution, which is accomplished solely by the CDA. The CDA is designed to recognize an instability and initiate control rod insertion before the power oscillations increase much above the noise level. The CDA capability of early detection and suppression of instability events is achieved by relying on the successive confirmation period element of PBDA. The CDA employs a low amplitude OPRM signal discriminator to minimize unnecessary spurious reactor scrams from neutron flux oscillations at or close to the OPRM signal noise level. The CDA identifies a confirmation density (CD), which is the fraction of operable OPRM cells in an OPRM channel that reach a target successive oscillation period confirmation count. When the CD exceeds a preset number of OPRM cells and any of the confirming OPRM cell signals reaches or exceeds the amplitude discriminator setpoint (S_{AD}), an OPRM channel trip signal is generated by the

CDA. A reactor trip is generated when multiple channel trips are generated, consistent with the reactor protection system (RPS) logic design. The bi-stable characteristic of the CD, where the value remains at zero except at the instability threshold, when it rapidly transitions to unity, provides excellent discrimination between stable and unstable operation. DSS-CD eliminates the reliance on the PBDA amplitude setpoint, which is included in the licensing basis of Option III. The instability suppression by the DSS-CD for high growth instability events occurs within a few full oscillation periods from the time the instability is sensed by the PBDA. Because the solution does not rely on oscillation growth to a specified high amplitude setpoint, suppression occurs within a short time from oscillation inception or close to the low amplitude OPRM signal discriminator and significant margin to the SLMCPR is provided. The concern of the time constant used for DSS-CD (0.95 second versus 6.0 seconds for OPRM) is addressed in Section 3.4.1 of NEDC-33075P, Revision 5, with respect to gaining significantly more safety margin for detecting power oscillations.

The NRC staff has reviewed the design concept and found it acceptable, because the DSS-CD solution complies with Criteria 10 and 12 of 10 CFR Part 50, Appendix A, and the DSS-CD solution enhances overall plant safety by providing reliable, automatic oscillation detection and suppression function while avoiding unnecessary scrams.

3.2 TRACG Code Qualification and Uncertainties

The TRACG is a GE proprietary version of the Transient Reactor Analysis Code (TRAC). The TRACG code is used to simulate limiting events to confirm the DSS-CD solution early oscillation detection and suppression capability.

TRACG uses advanced best-estimate one-dimensional and three-dimensional methods to model the phenomena that are important in evaluating the operation of BWRs. Best-estimate analyses performed with TRACG have been approved by the NRC to support licensing applications in different areas, including specific thermal-hydraulic instability performance and anticipated operational occurrence (AOO) transients.

TRACG has been extensively qualified against separate effects tests, component performance data, integral system effects tests, and full-scale BWR plant data. Section 5 of NEDC-33075P, Revision 5, provides a limited TRACG qualification and a treatment of uncertainties for critical power ratio (CPR) calculations following the code scaling, applicability and uncertainty (CSAU) methodology and the [ ] is described on pages 4-18 and 4-19, representing [ ]. To confirm the reasonableness of the proposed DSS-CD uncertainty levels, GE has performed the TRACG calculations [ ]. The results demonstrate that, even for these very large CPR oscillations, DSS-CD provides sufficient protection before safety limits are violated. A full review of the DSS-CD TRACG application report also indicates that it is acceptable to support the DSS-CD application. Therefore, the TRACG calculations in Section 4 of NEDC-33075P, Revision 5, are acceptable for this evaluation. An SE for the DSS-CD TRACG application will be issued separately, but is not required for the implementation of the DSS-CD LTR.

3.3 Reload Analysis and Plant Specific Application

The standard plant-specific review process, which applies to the reload process, consists of an applicability checklist (provided in Table 6-1 for two loop operation (TLO) and in Table 6-2 for single loop operation (SLO)), confirming that the generic application envelope, as defined in Section 4 of NEDC-33075P, Revision 5, is not exceeded. Section 6 of NEDC-33075P, Revision 5, describes the procedure for applicability extension to a new plant, and a new type of fuel or significant design change. Tables 6.3 and 6.4 document the procedure for an applicability extension. This procedure [

]. The results of this transient calculation are evaluated with the DSS-CD algorithm. The final MCPR is calculated and must show margin to SLMCPR as specified in Tables 4.1 and 4.6.

The NRC staff concludes that this applicability extension procedure is acceptable, because it involves a plant- and cycle-specific calculation of the most likely limiting instability scenario and the preventive nature of the DSS-CD scram.

3.4 Backup Stability Protection

Section 7 of NEDC-33075P, Revision 5, provides a description of BSP approaches that may be used when the OPRM system is inoperable up to and including operation in the MELLLA+ domain. The elements of the BSP are confirmed on a plant- and cycle-specific basis to provide consistency with the LTS general requirement of long-term applicability.

The example simulations in Section 4 of NEDC-33075P, Revision 5, indicates that the instabilities that grow rapidly to amplitudes sufficiently large to compromise the SLMCPR are very likely when operating the reactor at uprated powers and, especially, at reduced flow conditions (e.g., MELLLA+). [

]. GENE concluded and the NRC staff agrees that manual actions to prevent SLMCPR violations are not sufficient because of the fast nature of the transient. Thus, a BSP is required in case DSS-CD is declared inoperable. The BSP concept, documented in Section 7 of NEDC-33075P, Revision 5, is a technically acceptable solution to the backup issue.

The BSP methodology is composed of three solutions: (a) manual; (b) automated; and (c) BSP boundary. The manual BSP methodology is intended as a transition between DSS-CD and automated BSP or BSP boundary. Manual BSP will be used for the first 12 hours after DSS-CD is declared inoperable. This is consistent with the Standard TS requirement as it takes some time to switch from DSS-CD to the automated BSP protection, and it is therefore technically acceptable. Thereafter, the manual BSP is used in conjunction with either the automated BSP or the BSP boundary. With the automated BSP option, a scram is automatically generated if the reactor enters the exclusion region. With the BSP boundary option, the reactor power is reduced below the BSP line so that two RPT's will not result in immediate operation inside the exclusion region. Both the automated BSP and the BSP boundary rely on calculations to demonstrate that instabilities outside the exclusion regions are not likely.

The NRC staff concludes that the proposed BSP methodology is an acceptable solution, because it provides sufficient protection against SLMCPR violations commensurate with the probability of an instability event in the short period of time that they are active.

3.5 Technical Specification for DSS-CD

The proposed changes to the TSs are documented in Section 8 of NEDC-33075P, Revision 5. The proposed changes are acceptable, because they require DSS-CD to be operable and have operability and surveillance requirements consistent with other reactor protection systems. Should the DSS-CD be declared inoperable, initiation of actions to implement the manual BSP regions is required immediately, and implementation of either automated BSP or reduction of power below the BSP boundary is required. Without automated BSP, DSS-CD must be restored to operable within 120 days.

3.6 Instrumentation and Control

The DSS-CD and BSP trip function are implemented in software on the existing plant control room Power Range Neutron Monitoring System (PRNMS) equipment. The design of the existing PRNMS will be changed to incorporate a new panel video screen display to be used for setting values and for monitoring the function of the DSS-CD and BSP trip functions. Additionally, an alarm tile will be added to the main control room instrument panel to indicate the status of the DSS-CD and BSP trip functions. The safety related equipment has been previously approved by the NRC staff SE to NEDC-32410P-A, Revision 5, in the initial PRNMS installation.

3.6.1 Computer System Security

As stated in NEDC-32410P-A, Revision 5, the safety-related functions of the PRNMS have three levels of security. The first level requires a password only. The second level is implemented by the use of a keylock switch on each average power range monitor (APRM) and rod block monitor (RBM) chassis to provide Operate and INOP mode switching. The third level is implemented by requiring a correctly entered password and switching modes with the keylock switch. Passwords can be entered only by the operator at the APRM and RBM chassis and can not be remotely entered through the plant computer.

The first level of security, in combination with administrative controls, is used to prevent unauthorized performance of the following activities at the APRM chassis:

- Acceptance of reference thermal power values (%CTP) downloaded from the plant computer (for use by the APRM to calculate a new APRM gain adjustment factors (GAFs)).
- Acceptance of plant computer requests for the APRM and LPRM chassis to perform LPRM I/V curves.
- Bypassing or unbypassing an LPRM.
- Authorizing use of single recirculation loop operation setpoints.
- Changing assignments of transient test outputs.

The second level of security - keylock control of the chassis mode switch (without password) - is used to prevent unauthorized change of the chassis from the operate to the maintenance mode, from which surveillance and hardware calibration can be accomplished, some of which will take the chassis out of service (temporarily disabling the safety function).

The third level of security - keylock controlled access to the chassis maintenance mode plus password controlled access to setup screen - is used to prevent unauthorized changing of setpoint values or parameters and chassis configuration items. This security level is used for accepting LPRM GAFs downloaded from the plant computer via the RBM chassis.

The second and third levels of security are used on both the APRM and RBM. The first level of security is used only on the APRM. All three levels of security are accessible only under administrative controls at the display panel.

Critical data received from other systems are validated prior to their use by the APRMs. The data to be validated includes items such as GAFs, %CTP, LPRM detector signals, and recirculation flow loop differential pressure signals. The GAFs and %CTP values are determined by the plant computer and then downloaded to the APRMs only after the values are confirmed and accepted by the plant operator at the APRM display panels.

Additionally, the APRM is designed to ignore, without extra processing burden, excessive messages or requests from the RBM, thus providing information isolation from the plant computer in the event of a denial of service type of cyber attack.

On the basis of the previously approved PRNMS LTR NEDC-32410P-A, including the security issues discussed in this SE, the NRC staff concludes that the computer security measures discussed above effectively isolate the safety-related implementation of the DSS-CD and BSP trip functions from the plant computer and from outside interference and, therefore, are acceptable.

3.6.2 System Development

The NRC staff reviewed the development of the DSS-CD and BSP trip functions in two audits. The purpose of the audits was to ensure that the DSS-CD and BSP trip functions were developed in conformance with the criteria in 10 CFR Part 50, Appendix B.

In the first audit, the NRC staff reviewed the following planning and requirements development activities and products using the documents listed in Table 1.

Activity	Product
Planning	Software Management Plan Software Development Plan Software Quality Assurance Plan Software V&V Plan Software Configuration Management Plan
Requirements	Software Requirements Specification

Configuration Management Requirements Report

The NRC staff found the planning documents to be acceptable. The planning requirements in the documents were consistent with industry practices that are commensurate with safety-related software development quality assurance activities.

The NRC staff reviewed the software requirements specification and the configuration management requirements report. The NRC staff found that the requirements-based documents were acceptable and adhered to procedures controlling safety-related system development activities, which are controlled by GENE through its 10 CFR Part 50, Appendix B, quality assurance program.

Conformance with the planning requirements were then reviewed by the NRC staff in a second audit of the DSS-CD and BSP trip functions software development processes after these systems had been implemented as software, and the DSS-CD system had been integrated with the GENE NUMAC PRNMS. The audit topics in the second audit were classified into a number of software development activities and associated products. The following activities and products were included in the second audit:

Activity	Product
Requirements	Software Requirements Specification
Design	Software Design Specifications
Implementation	Software Coding
Integration	Software Test Plans Factory Acceptance Testing

In the second audit, the NRC staff reviewed the DSS-CD software development process after the DSS-CD had been implemented as software and integrated with the PRNMS. The NRC staff selected four requirements for tracing the development effort through the GE baseline development life cycle. These requirements are listed in Table 1.

The NRC staff used the documents listed in Table 3 as the source of the information documenting the development activities conducted by GENE. The NRC staff reviewed the software requirements specifications, associated data sheets, test cases, and related test results reports.

On the basis of the second audit, the NRC staff identified the issues in Section 3.6.1 through Section 3.6.3 below as open items that must be addressed by licensees to implement the DSS-CD trip function and, optionally, the BSP trip function to detect and suppress power oscillations.

3.6.3 Control of Licensing Basis Set Points and Adjustable Settings

Document No. 26A6050AA, Section 2.4, Definitions, provides the following definitions for parameter states:

STATE	Characterization of the ability to change the parameter value. A STATE of a parameter is either FROZEN, FIXED, or ADJUSTABLE.
FROZEN	The value of the parameter is hardwired in the software/hardware and can not be modified.
FIXED	The value of the parameter is fixed at the Set Value per the system licensing basis. However, an adjustable range is built into the software/hardware to allow changing the value consistent with possible changes to the system licensing basis.
ADJUSTABLE	The parameter may be varied between the specified Minimum and Maximum Values by input at the operator console. The Set Value is the default upon system initiation.

Document No. 26A6050AA defined the parameters listed in Table 4 as FIXED parameters and the parameters in Table 5 as ADJUSTABLE parameters.

Two parameters in Table 4 (N_P and S_p) are specific to the PBDA, therefore, although these two parameters are FIXED parameters, the operator-adjustable values for these two parameters are not applicable to the licensing basis of the plant since the PBDA is retained as defense-in-depth.

Two parameters in Table 5 (N_{AL} and AL) were appropriately defined by GENE as parameter values that may be changed without considering the effect on the plant licensing bases. Three parameters in Table 5 (m, $P_{BSP\text{-}Trip}$, and $W_{BSP\text{-}Trip}$) can cause the operator to actuate a RPS trip when the BSP trip function is selected by the operator as the primary stability protection system for protecting the reactor from power oscillation instability events. These parameters are ADJUSTABLE parameters. Although GE characterizes these parameters as ADJUSTABLE, since the BSP trip function is credited as a licensing basis system, the value of these parameters are controlled and can only be changed with guidance provided by GE.

On the basis of the above parameter definitions, the NRC staff concluded that the FIXED parameter values N_{Th}, P_b, W_b, T_{min}, ε_0, M_{AX}, $LPRM_{min}$, and f_c, and the ADJUSTABLE parameter values m, $P_{BSP\text{-}Trip}$, and $W_{BSP\text{-}Trip}$ are licensing basis values, and should be controlled as such by licensees using the DSS-CD trip function, and, as appropriate, the BSP trip function.

3.6.4 Use of DSS-CD Trip Function and BSP Trip Function in Plants Other Than Brunswick Steam Electric Plant, Units 1 and 2

Section 3.1 of the Project Plan (Document No. 1208-JXB15-KB0), which is specific to Brunswick Steam Electric Plant, Units 1 and 2, stated that there is no requirement to verify and validate the DSS-CD trip function code for transportability considerations with respect to using this product in other NUMAC PRNM plants. Therefore, the NRC staff concluded that if licensees other than the licensee for Brunswick Steam Electric Plant, Units 1 and 2, install the DSS-CD trip function, those licensees must ensure this product is applicable in their plant licensing bases, including the optional BSP trip function if it is to be installed.

3.6.5 Manual Actuation of the BSP Trip Function

If the BSP trip function is to be manually enabled by a reactor operator upon loss of the DSS-CD trip function, the TSs provide an associated time required for this action to be completed and a basis for that time.

Licensees opting to implement the BSP trip function must address the procedure by which the BSP trip function will be enabled upon loss of the DSS-CD trip function, with the proposed time required for this action to be completed and a basis for that time.

The NRC staff reviewed the DSS-CD trip function and the BSP trip function computer security and development processes, the software requirements specifications, associated data sheets, test cases, and related test results reports. The NRC staff found the requirements-based documents are acceptable in the areas the NRC staff reviewed, and reflect adherence to GENE procedures controlling safety-related system development activities, which are controlled by GENE through its 10 CFR Part 50, Appendix B, quality assurance program.

The NRC staff found that GENE followed its system development procedures appropriately in translating the audited system requirements into the system described in the Project Plan. The NRC staff concludes that the development activities performed by GENE are generally consistent with 10 CFR Part 50, Appendix B, system development procedures and are, therefore, acceptable.

4.0 CONCLUSION

The NRC staff has reviewed the subject LTR (References 1 and 4) and the response to the NRC staff's RAIs (References 6, 7, and 8) to determine acceptability of the LTR, NEDC-33075P, Revision 5.

The existing Solution III is already approved for plant operation up to 20 percent EPU. DSS-CD is an extension of Solution III, where the need to determine the PBDA scram setpoint with a DIVOM correlation is eliminated by setting the setpoint to the Amplitude Discriminator value (i.e., coherent oscillations just above a nominal noise level will result in an automated scram). Thus, DSS-CD is, in essence, a Solution III implementation with the PBDA setpoint set at very conservative setting.

The DSS-CD is a technically acceptable methodology for any reactor operating up to MELLLA+ conditions which are analyzed with TRACG (which is approved in a separate SE). The confirmation analyses documented in Section 4 of NEDC-33075P, Revision 5, indicate that the DSS-CD methodology provides significant protection against MCPR criteria during anticipated instability events even under high-power-density conditions, including EPU and MELLLA+.

Plants operating in the MELLLA+ domain require a backup methodology that does not rely on manual operator actions in the event that DSS-CD is declared inoperable. The analyses documented in NEDC-33075P, Revision 5, indicate that for reactors operating in the MELLLA+ domain: a) instabilities are very likely following flow reduction events; b) these instabilities develop in a time frame of a few seconds, so that manual operations to suppress them are not acceptable; and c) the consequences of these instabilities can be serious.

A BSP methodology with related TS is described in Section 7 of NEDC-33075P, Revision 5. TS have been provided for the two different actions related to the manual BSP boundary (Section 7.3) and the automated BSP (Section 7.4) options. The NRC staff review of the proposed backup options is provided below:

a. When the DSS-CD solution is inoperable, the automated BSP option requires that the licensee implement the automated BSP scram option within 12 hours. The plant then has 90 days to provide a report to the NRC staff with a corrective action plan and schedule for NRC staff review.

b. If the automated BSP option cannot be implemented, the TS requires the licensee to implement the manual BSP option within the next 12 hours. This would require the licensee to reduce operation of the plant to below the BSP boundary defined in the core operating limits report (COLR). The licensee then has 120 days to restore the DSS-CD solution or shutdown the plant. If neither the automated or manual BSP options can be implemented, the plant must be placed in a condition in which the limiting condition for operation (LCO) does not apply (i.e., less than 20 percent RTP or Mode 2) in less than 4 or 6 hours, depending on the LCO applicability.

The NRC staff concludes that the backup options with the proposed TS actions will provide adequate protection against an instability event when the DSS-CD solution is inoperable. Therefore, the NRC staff concludes that the proposed backup options and associated TSs are acceptable.

The DSS-CD methodology is technically acceptable to detect and suppress oscillations, should they occur. Therefore, the NRC staff concludes that DSS-CD is a technically acceptable methodology for any reactor operating up to EPU conditions. The NRC staff has concluded that LTR NEDC-33075P, Revision 5, is acceptable with conditions and limitation described as follows:

1. The NRC staff has reviewed on a separate report the implementation of DSS-CD using the approved GENE Option III firmware and software and found it acceptable. Implementations on other Option III platforms will require plant-specific review.

2. Tables 6.1 and 6.2 of NEDC-33075P, Revision 5, document a plant-specific applicability checklist, which contains specific criteria that must be reviewed and satisfied for each core reload. This methodology is a technically acceptable process for plant- and cycle-specific reviews of DSS-CD applicability.

3. For situations where the plant applicability checklist is not satisfied (e.g., introduction of a new fuel type), Tables 6.3 and 6.4 of NEDC-33075P, Revision 5, describe a technically acceptable procedure to extend the future applicability of DSS-CS.

4. Section 8 of NEDC-33075P, Revision 5, provides a description of required changes to TSs and an example is provided in Appendix A. The proposed TSs are acceptable for the implementation of DSS-CD.

5. Table 6.5 of NEDC-33075P, Revision 5, describes the fuel transition scenarios, which are subject to a plant-specific review for each application.

6. Application of an alternative to the generic CDA setpoints with respect to the susceptibility of a plant's intrinsic noise will require a plant-specific review.

7. The hardware components required to implement DSS-CD are expected to be those currently used for the approved Solution III. If the DSS-CD hardware implementation deviates significantly from the approved Solution III, a hardware review by the NRC staff may be necessary.

8. The NRC staff concludes that the plant-specific settings for eight of the FIXED parameters and three of the ADJUSTABLE parameters appear to be licensing basis values. The process by which these values will be controlled must be addressed by licensees.

9. The NRC staff concludes that if plants other than Brunswick Steam Electric Plant, Units 1 and 2, use the DSS-CD trip function, those plant licensees must ensure the DSS-CD trip function is applicable in their plant licensing bases, including the optional BSP trip function, if it is to be installed.

5.0 REFERENCES

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2. NEDC-33075P, Revision 3, "General Electric Boiling Water Reactor Detect and Suppress Solution - Confirmation Density," January 2004.

3. Letter, George Stramback (GE) to USNRC, DSS-CD Licensing Topical Report, NEDC-33075P Revision 4, MFN 04-073, August 2, 2004, ADAMS Accession No. ML042180428.

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8. Letter, George Stramback (GE) to USNRC, Response to NRC RAI regarding DSS-CD LTR, MFN 04-001, January 23, 2004.

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15. Letter, George Stramback (GE) to USNRC, Information to Support NRC Review of MELLLA+ and DSS-CD LTRs, MFN 03-037, June 4, 2003, ADAMS Accession No. ML031600645.

16. Letter, George Stramback (GE) to USNRC, NRC Review of TRACG Code for DSS-CD, MFN 03-040, June 23, 2003, ADAMS Accession No. ML031760562.

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20. Letter, George Stramback (GE) to USNRC, Proposed TRACG LTR - Revised Scope. MFN 04-006, February 6, 2004, ADAMS Accession No. ML040420435.

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27. Letter, George Stramback (GE) to USNRC, GE Evaluation of OPRM Performance during Instability Events at Nine Mile Point Nuclear Unit 2 and Perry Nuclear Power Plant, MFN 06-89, March 24, 2006, ADAMS Accession No. ML060880442.

28. Letter, George Stramback (GE) to USNRC, CPR Margin – DSS-CD LTR (NEDC-33075P, Detect and Suppress Solution – Confirmation Density), MFN 06-105, April 17, 2006, ADAMS Accession No. ML061100204.

Attachments:
1. Resolution of Comments
2. TER (Proprietary)

Principle Contributors: T. Huang
M. Waterman

Date: November 27, 2006

Table 1. Documentation Reviewed by Staff During First Audit

Document Number/Revision	Date	Document Title	Description
23A5162 Rev 2	10/29/90	NUMAC Software Management Plan	The SMP describes the process to be used for the design, development, and maintenance of NUMAC product software.
No Doc. Number	1/14/99	PRNM NUMAC Problem Report Tracking Matrix	This matrix tracks NUMAC PRNM problems and their resolution. This matrix was provided as an example report illustrating the process by which GE tracks problem resolutions.
23A5163 Rev 2	10/29/90	NUMAC Software Verification and Validation Plan	This document describes the Verification and Validation Plan (VVP) to be used for all NUMAC products. The plan clarifies and/or supplements the Engineering Operating Procedures under which all design work is done. The VVP is designed to work in conjunction with the NUMAC Software management Plan.
23A5161 Rev 1	10/20/90	NUMAC Software Configuration Management Plan	This document describes the Software Configuration Management Plan to be used for all NUMAC products. This plan establishes a formal set of standards and procedures to ensure effective configuration management of NUMAC software products and provide visible status and control of software documentation items.
26A6050 Rev 1	3/21/03	Oscillation Power Range Neutron Monitor for Stability DSS-CD	This specification establishes the performance requirements of the OPRM for the DSS-CD.
26A6050AA Rev 2	3/21/03	Oscillation Power Range Monitor for Stability DSS-CD	This document is the Nuclear Safety Analysis document that defines the requirements basis for the DSS-CDA.

Table 1. Documentation Reviewed by Staff During First Audit

Document Number/Revision	Date	Document Title	Description
GENE 0000-0016-7639	5/14/03	NUMAC Power Range Neutron Monitoring System (PRNM) Operating Experience Feedback and Recommendations Update Report	The purpose of this report is to consolidate the experience information in a single report, update information and recommendations previously provided where applicable, and provide information and recommendations related to issues that have been identified.
3407 Rev 4	7/15/03	Contract N. 2407, Work Authorization No. 3407-4, Change Order No. 3407-4-17	This document is the Brunswick Purchase Order
1208-JXB15-KB0 Rev 1	8/7/03	System Project Plan	This project plan provides the work scope and deliverables for implementation of the new Stability Detect and Suppress Solution - Confirmation Density (DSS-CD) for Brunswick NPP, Units 1 and 2. The DSS-CD will be incorporated into the as-built NUMAC Power Range Neutron Monitor (PRNM) system.
RMCN02681 Rev 0	9/18/03	Brunswick PRNMS Requirements Spec Data Sht 24A5221RM	This document summarizes the basis for each change to the existing Brunswick PRNMS defined by 24A5221RM Rev 3.

Table 2. Requirements Reviewed by Staff

Document No.	Requirement No.	Status	Comments
26A6050AA	3.1, Sht 8 3.2.5, Sht 21	OK	Detection Algorithm Specification. Check the algorithm that enables/disables the OPRM on the basis of reactor power and recirculation flow. Confirm the values for P_b and W_b are in the algorithm shown on Sht 8.
26A6050AA	3.1, Sht 8	OK	Detection Algorithm Specification. Check the process by which the LPRM signals are filtered, combined into OPRM cells, time averaged, and normalized.
26A6050AA	3.2.6, Sht 22	OK	Filters. Review the Filter equations and verify the values of the filter coefficients shown on Sht 22 are in the coding and have been tested.
26A6050AA	3.1.1, Sht 9	OK	Determine Maximum (Peak), Minimum (Valley) and Period. Compare the logic shown on Sht 9 with the coding and verify the testing.

Table 3. Documents Reviewed by Staff During Second Audit

Document Number/Revision	Date	Document Title	Description
1208-JXB15-KB0 Rev 0	7/7/03	Progress Energy Carolinas, Inc., Brunswick Nuclear Plant, Units 1 and 2, NUMAC Power Range Neutron Monitoring System, Implementation of DSS-CD for PRNM, Project Plan (Project Quality Plan/Project Work Plan)	This project plan provides the work scope and deliverables for implementation of the new Stability Detect and Suppress Solution - Confirmation Density (DSS-CD) for Brunswick Nuclear Plant, Units 1 and 2. The DSS-CD will be incorporated into the as-built NUMAC Power Range Neutron Monitor (PRNM) system.
26A6050 Rev 1	7/28/03	Oscillation Power Range Monitor for Stability DSS-CD - Performance Specification	This specification establishes the performance requirements of the OPRM for the DSS-CD.
26A6050AA Rev 4	11/6/03	Oscillation Power Range Monitor for Stability DSS-CD - Data Sheet	This data sheet establishes the ranges and nominal values of the parameters included in the design of the OPRM DSS-CD.
24A5221 Rev 8	7/15/03	NUMAC Power Range Neutron Monitor System Requirements Specification	This specification defines the design and performance requirements for the design and manufacture of a NUMAC based PRNM system.
24A5221RM Rev 4	11/11/03	PRNM Requirements Specification - Data Sheet	This requirements specification data sheet establishes the specific design requirements for the Brunswick 1&2 NUMAC PRNM systems.
26A6192 Rev 0	11/14/03	NUMAC Average Power Range Neutron Monitor with DSS-CD, Performance Specification	This specification defines the performance characteristics and application limits for a generic NUMAC APRM instrument that includes the OPRM DSS-CD and automatic BSP functions.

Table 3. Documents Reviewed by Staff During Second Audit

Document Number/Revision	Date	Document Title	Description
26A6192RM Rev 0	11/14/03	NUMAC Average Power Range Neutron Monitor with DSS-CD, Data Sheet	This performance specification data sheet, in conjunction with the generic specification, 26A6192, Rev. 0, defines the performance characteristics and application limits for the Brunswick 1&2 NUMAC APRM.
26A5772 Rev 4	12/5/03	APRM User's Manual - Performance Specification	This performance specification provides the APRM Instrument description, the function descriptions, and miscellaneous information such as descriptions of the top-level menus, abbreviations and acronyms, and symbols used in the manual.
eDRF 0000-0017-9229 Rev A	11/16/03	APRM (with DSS-CD) Functional Controller Software Design Specification	This document comprises the high-level design of the APRM functional controller software. The purpose of the document is to define the software design in sufficient detail such that software implementation can be undertaken without need for major design decisions. The specification also provides a means for understanding how the functional controller software fulfills design input requirements.
eDRF 0000-0017-9229 Rev A	11/16/03	APRM (with DSS-CD) Functional Controller Software Design Specification Data Sheet	This document describes the Brunswick 1&2 APRM functional controller software design by way of listing the exceptions to the parent document.
Software listing of OPRM.C	12/11/03	Oscillation Monitor Package for NUMAC APRM	This package contains the oscillation monitor task and the procedures necessary to support stability-ASP access.

Table 3. Documents Reviewed by Staff During Second Audit

Document Number/Revision	Date	Document Title	Description
Test Results Reports	10/6/03	N/A	These documents list the test results from the Factory Acceptance Tests.

Table 4. Document No. 26A6050AA FIXED Parameters

Parameter	Definition
T_{min} (sec)	The Period Based Algorithm (PBA) oscillation period lower time limit for anticipated reactor instability. If the time between successive peaks or valleys is less than T_{min}, then it is not indicative of an anticipated reactor instability.
ε_0 (ms)	The PBA period tolerance. This parameter defines the limits within which successive oscillation periods may vary from the first (base) oscillation period in order to increment the number of confirmation counts. If the difference between an oscillation period and the base period is not within this tolerance, the number of confirmation counts is reset to zero.
M_{AX}	An OPRM configuration constant representing maximum number of OPRM cells along an instability symmetry axis.
N_P[1]	Period Based Detection Algorithm (PBDA) successive confirmation count setpoint. After a base period is established, the period confirmation count is increased by one (1) each time a valley or peak meets the PBA confirmation criteria. Reaching N_P is indicative of reactor instability.
S_P[1]	PBDA amplitude trip setpoint. When the cell exceeds S_P after the confirmation count has reached N_P, ASF (automatic suppression function) is required.
N_{Th}	CDA successive confirmation count setpoint. The DSS-CDA initiates a reactor trip when the number of successive confirmation counts exceeds this value.
$LPRM_{min}$	The minimum number of operable LPRM input signals to an OPRM cell for the OPRM cell to be considered operable. Cell sensitivity generally increases with fewer operable LPRMs.
f_c (Hz)	Filter cutoff frequencies (Hz) for the conditioning filters to remove high frequency noise from the LPRM signals and to time average the LPRM signals.
P_b	OPRM Armed Region Lower Power Boundary (% Rated Power). The Simulated Thermal Power (STP) from the APRM channel is used to provide the power level. P_b is set to the % rated power level corresponding to the MCPR Monitoring Threshold.
W_b	OPRM Armed Region Upper Flow Boundary (% Rated drive flow). The total recirculation flow (average of both loops) from the APRM channel is used to provide the recirculation drive flow. W_b is set to 70% rated drive flow for MELLLA operation and 75% rated drive flow for MELLLA+ operation.

Note: 1. The PBDA is not credited in the system licensing basis.

Table 5. Document No. 26A6050AA ADJUSTABLE Parameters

Parameter	Definition
N_{AL}	Successive confirmation count alarm setpoint for the CDA.
AL	Flag used to establish the OPRM cell on which the PBA/CDA alarm is based. A value of 1 for AL bases the PBA/CDA alarm on any one OPRM cell exceeding a successive confirmation count of N_{AL}. A value of 2 for AL bases the PBA/CDA alarm on the second OPRM cell exceeding a successive confirmation count of N_{AL}.
m[1]	Slope of the automatic Backup Stability Protection (BSP) APRM flow biased trip and rod block setpoint linear segments. m is set at an approximate typical flow control line value.
$P_{BSP\text{-}Trip}$[1]	Automatic BSP APRM flow biased trip setpoint power intercept (% Rated power). The STP from the APRM channel is used to provide the power level. $P_{BSP\text{-}Trip}$ is set at or below the BSP Region I intercept at the plant natural circulation line.
$P_{BSP\text{-}RB}$[2]	Automatic BSP APRM flow biased rod block setpoint power intercept (% Rated power). The STP from the APRM channel is used to provide the power level. $P_{BSP\text{-}RB}$ is set below $P_{BSP\text{-}Trip}$ based on plant specific operational and setpoint methodology considerations.
$W_{BSP\text{-}Trip}$[1]	Automatic BSP APRM flow biased trip setpoint drive flow intercept (% Rated drive flow). The total recirculation flow (average of both loops) from the APRM channel is used to provide the recirculation drive flow. $W_{BSP\text{-}Trip}$ is selected such that the BSP Region I is bounded by the APRM flow biased trip setpoint.
$W_{BSP\text{-}RB}$[2]	Automatic BSP APRM flow biased rod block setpoint drive flow intercept (% Rated drive flow). The total recirculation flow (average of both loops) from the APRM channel is used to provide the recirculation drive flow. $W_{BSP\text{-}RB}$ is set above $W_{BSP\text{-}Trip}$ based on plant specific operational and setpoint methodology considerations.

Notes: 1. Although this value is characterized by GE as an ADJUSTABLE value, if the BSP trip function is credited as a licensing basis system, this value must be controlled consistent with the guidance provided by GE.

2. Rod block limits are not licensing basis limits.

RESOLUTION OF COMMENTS
ON DRAFT SAFETY EVALUATION FOR NEDC-33075P,
"GENERAL ELECTRIC BOILING WATER REACTOR DETECT AND SUPPRESS SOLUTION - CONFIRMATION DENSITY"

By e-mails dated August 14, 17, and 22, 2006, (ADAMS Accession Nos. ML062780046, ML062780050, and ML062780048, respectively) General Electric Nuclear Energy (GENE) provided comments on the draft safety evaluation (SE) for NEDC-33075P. The following is the NRC staff's resolution of these comments.

GENE Comment:

Page 1 title - wrong topical referenced.

NRC Resolution:

Replaced NEDC-32938P with correct title NEDC-33075P.

GENE Comment:

Page 1 misspelled "safety limit minimum critical for power (SLMCPR)."

NRC Resolution:

Replaced "safety limit minimum critical for power (SLMCPR)" with "safety limit minimum critical power ratio (SLMCPR)."

GENE Comment:

In Section 3.6.3, GENE noted that one of the parameters was incorrectly labeled and also clarified the description of the parameters.

NRC Resolution:

The NRC staff agrees with GENE's comments and have revised Section 3.6.3 to read:

"These parameters are ADJUSTABLE parameters. Although GE characterizes these parameters as ADJUSTABLE, since the BSP trip function is credited as a licensing basis system, the value of these parameters are controlled and can only be changed with guidance provided by GE.

On the basis of the above parameter definitions, the NRC staff concluded that the FIXED parameter values N_{Th}, P_b, W_b, T_{min}, ε_0, M_{AX}, $LPRM_{min}$, and f_c, and the ADJUSTABLE parameter values m, $P_{BSP\text{-}Trip}$, and $W_{BSP\text{-}Trip}$ are licensing basis values, and should be controlled as such by licensees using the DSS-CD trip function, and, as appropriate, the BSP trip function."

ATTACHMENT 1

GENE Comment:

GENE has noted that Conclusion 3 needs to be clarified.

NRC Resolution:

The NRC staff has reviewed the comment and agrees. As such conclusion 3 has been clarified as such:

"The existing Solution III is already approved for plant operation up to 20 percent EPU. DSS-CD is an extension of Solution III, where the need to determine the PBDA scram setpoint with a DIVOM correlation is eliminated by setting the setpoint to the Amplitude Discriminator value (i.e., coherent oscillations just above a nominal noise level will result in an automated scram). Thus, DSS-CD is, in essence, a Solution III implementation with the PBDA setpoint set at very conservative setting. Therefore, the NRC staff concludes that DSS-CD is a technically acceptable methodology for any reactor operating up to EPU conditions."

GENE Comment:

GENE noted that Conclusion 13 and Tables 4 and 5 needed to be corrected to reflect the mislabeled parameter in Section 3.6.3.

NRC Resolution:

The NRC staff agrees with GENE's comment and has revised Conclusion 13 and the associated Tables 4 and 5 to reflect the mislabeled parameter.

GENE Comment:

GENE noted that in Section 3.2 could imply that the DSS-CD SE is pending the approval of the TRACG topical report.

NRC Resolution:

The NRC staff agrees with GENE's comment and has revised Section 3.2 to state:

"Therefore, the TRACG calculations in Section 4 of NEDC-33075P, Revision 5, are acceptable for this evaluation. An SE for the DSS-CD TRACG application will be issued separately, but is not required for implementing the DSS-CD LTR."

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EXECUTIVE SUMMARY

Under certain conditions, boiling water reactors (BWRs) may be susceptible to coupled neutronic/thermal-hydraulic instabilities. These instabilities are characterized by periodic power and flow oscillations. If these oscillations become large enough, and the associated density waves contain a sufficiently high void fraction, the fuel cladding integrity safety limit could be challenged.

Several different stability long-term solution (LTS) options have been developed for BWRs. Certain solutions depend upon automatic reactor instability detection and suppression to show compliance with licensing requirements. The Detect and Suppress Solution – Confirmation Density (DSS-CD) consists of hardware and software for the automatic detection and suppression of stability related power oscillations and represents an evolutionary step from the stability LTS Option III.

DSS-CD introduces an enhanced detection algorithm, the Confirmation Density Algorithm (CDA), which reliably detects the inception of power oscillations and generates an early power suppression trip signal prior to any significant oscillation amplitude growth and Minimum Critical Power Ratio (MCPR) degradation. This report provides a generic licensing basis for GE BWR/3-6 product lines, GE14 and earlier GE fuel designs and operating envelopes up to and including Extended Power Uprate (EPU) and Maximum Extended Load Line Limit Analysis Plus (MELLLA+). A standard procedure is identified for plant specific confirmations of reload designs and other design changes that may affect the DSS-CD generic licensing basis.

REVISIONS

Revision 1:

1. Editorial clarifications and corrections.
2. Updated acknowledgement list.
3. Expanded proprietary marking to include GE proprietary processes.

Revision 2:

1. Minor editorial changes.
2. Correct channel trip designation in Section 3.2 for consistency with Figure 3-1.
3. Clarify in Sections 3.5 and 4.5 the MCPR monitoring threshold application to define the Armed Region boundary.
4. Revise "filter corner frequency" to "filter cutoff frequency" throughout the report for consistency.
5. Lower T_{min} value to bound expected period range for MELLLA+ operation.
6. Adjust f_c permissible range consistent with the revised T_{min} value.
7. Identify OPRM cell and channel responsiveness requirements, and clarify relationship to confirmation density setpoint.
8. Change the initial setting for the Period Based Algorithm (PBA) adjustable parameters consistent with plant operating experience.

Revision 3:

1. Minor editorial changes.
2. Clarify terminology use of RPS channel, OPRM channel and OPRM cell.
3. Change DSS-CD system operability requirement in Section 3.5.
4. Change unresponsive OPRM channel to inoperable (INOP) channel status.
5. Clarify that the selection of DSS-CD alarm setpoint is optional.
6. Clarify Manual BSP Region generation cycle exposure requirements, application procedure, and BSP Boundary feature.
7. Define HFCL for MELLLA+ and clarify use for MELLLA+ applications.
8. Identify BSP options
9. Add section of example Technical Specification.
10. Simplify MCPR margin applicability envelope definition.
11. Clarify Armed Region Boundary flow dependence.
12. Clarify that TRACG is not used to establish the SLMCPR.

13. Specify PBA cutoff frequency and period tolerance values.
14. Eliminate PBA calibration requirement.
15. Revise PBDA confirmation count setpoint value.
16. Specify TRACG fuel transition cases for expanding DSS-CD applicability envelope.

Revision 4:

1. Minor editorial changes.
2. Add to CDA an OPRM cell signal amplitude discriminator.
3. Add explicit TRACG OPRM cell modeling and apply the detection algorithm to OPRM cell signals instead of hot channel signals.
4. Address single loop operation.
5. Add Figure 3-1 to illustrate the DSS-CD detection algorithms time of trip for a growing oscillation.
6. Add basis for the selected OPRM signal averaging cutoff frequency value.
7. Specify a single period tolerance value in Table 3-5.
8. Correct C1AX entry in Table 5-3.
9. Clarify feedwater temperature considerations for Manual BSP Region generation.
10. Add optional exposure dependent BSP regions and boundary.
11. Correct Figures 7-2 and 7-4.
12. Revise the proposed requirement and purpose of TS Required Action I.3 to require NRC acceptance of corrective action plan and schedule.

Revision 5:

1. Minor editorial changes.
2. Clarify on-line implementation.
3. Correct BSP Boundary calculation procedure for xenon concentration and feedwater temperature in Table 7-2.
4. Update Tables 4-4, 4-5, 4-9 and 4-10, Figures 4-1 through 4-27 and 4-32 through 4-45, and the bounding CSAU oscillation component relative uncertainty to account for a void reactivity coefficient correction and the use of a transient CPR model in TRACG.
5. Clarify potential susceptibility to spurious scrams for plants exhibiting high noise level during stable operation.
6. Address partial flow reduction events.
7. Update Table 8-1, Technical Specifications, and associated Bases.

Revision 6:

(Note: The revision bars provided in Appendixes A and B do not reflect changes regarding Revision 6 of this LTR. The revision bars provided in Appendixes A and B indicate changes relative to the TS and Bases proposed in Reference 13 for BWR/4 Standard Technical Specifications.)

1. Added statement to Section 3.3.1.9 that each plant-specific application will address the margins to the SLMCPR and the margins presented in the DSS-CD LTR consistent with RAI 6 of MFN 06-105 [Ref 16].
2. Revised Section 4.4.2 and Figure 4-45 to reflect the correct timing for the SLO event. The NRC was informed of the required changes in conference call dated June 11, 2007 and agreed the changes should be incorporated in the 'A' version of the LTR.
3. Created 'A' version by adding the NRC Final Safety Evaluation [Ref 18] and GEH's responses to the NRC's requests for additional information (RAI) [Refs 14, 15, 16, and 17].
4. Deleted acknowledgement page.
5. Updated Generic Licensing Basis RAI 2 and BSEP Methodology RAI 6 of MFN 04-001 [Ref 14] consistent with commitments made in RAIs 8 and 11 of MFN 05-148 [Ref 15]. Note revision bars are not shown for the revisions to the RAIs since the RAIs were not part of Revision 5.
6. Added 'RAI' in the list of abbreviations.

ACRONYMS AND ABBREVIATIONS

Term	Definition
ABA	Amplitude Based Algorithm
ABWR	Advanced Boiling Water Reactor
AD_j	Amplitude Discriminator State
AGE	Approved GE
ANGE	Approved Non-GE
AOO	Anticipated Operational Occurrence
APRM	Average Power Range Monitor
ATWS	Anticipated Transient Without Scram
A_n	Averaged OPRM cell signal
BB	Boiling Boundary
BOC	Beginning Of Cycle
BSP	Backup Stability Protection
BT	Boiling Transition
BWR	Boiling Water Reactor
CCFL	Counter Current Flow Limitation
CD	Confirmation Density
CD_j	j^{th} OPRM Channel Confirmation Density
CDA	Confirmation Density Algorithm
CHAN	Fuel Channel
CPR	Critical Power Ratio
CSAU	Code Scaling, Applicability and Uncertainty
C_n	Normalized OPRM cell signal
DIVOM	Delta over Initial MCPR Versus Oscillation Magnitude
DR	Decay Ratio
DSS-CD	Detect and Suppress Solution – Confirmation Density
DVC	Dynamic Void Coefficient
ΔCPR	Delta Critical Power Ratio
ΔT_{FW}	Delta Feedwater Temperature

Term	**Definition**
E	Axial loss of PBA efficiency
ECCS	Emergency Core Coolant System
ECP	Engineering Computer Program
EOC	End Of Cycle
ε	Period Tolerance
ε_{Input}	PBA Period Tolerance Selection
EPU	Extended Power Uprate
f_C	Conditioning Filter Cutoff Frequency
FCL	Flow Control Line
FCV	Flow Control Valve
FMCPR	Final Minimum Critical Power Ratio
FTTC	Fuel Thermal Time Constant
F_{CD}^{Max}	Maximum response fraction ignoring axial PBA inefficiencies
GDC	General Design Criteria
GESTAR	General Electric Standard Application for Reload Fuel
GEXL	GE Boiling Transition Correlation
GRA	Growth Rate Algorithm
GR_3	GRA Maximum Allowable Growth Rate
GSF	Generic Shape Function
GT	Guide Tube
HFCL	High Flow Control Line
HT	Heat Transfer
ICA	Interim Corrective Action
ICPR	Initial Critical Power Ratio
IMCPR	Initial Minimum Critical Power Ratio
JP	Jet Pump
KKL	Kernkraftwerk Leibstadt
L	Low Importance
LOCA	Loss Of Coolant Accident
LPCI	Low Pressure Coolant Injection

Term	Definition
LTR	Licensing Topical Report
LTS	Long-Term Solution
LPRM	Local Power Range Monitor
LUA	Lead Use Assembly
M	Medium Importance
MCPR	Minimum Critical Power Ratio
MELLLA+, M+	Maximum Extended Load Line Limit Analysis Plus
M^{j}_{OP}	Number of Operable OPRM cells for j^{th} OPRM Channel
M^{j}_{RS}	Number of Responsive OPRM cells for j^{th} OPRM Channel
M^{j}_{AX}	Largest Number of OPRM cells Aligned Along a Regional Mode Instability Axis of Symmetry
M^{j}_{CD}	Number of OPRM cells at or above N_{Th} for j^{th} OPRM channel
M^{j}_{DL}	Number of Operable OPRM cells with Exclusive Input from D Level LPRMs
MG	Motor Generator
MOC	Middle Of Cycle
NA	Not Applicable
N_{Al}	Successive Confirmation Alarm Setpoint
NCL	Natural Circulation Line
N_i	Successive Confirmation Count of the i^{th} OPRM cell
N_P	PBDA Successive Period Confirmation Setpoint
NMS	Neutron Monitoring System
NRC	Nuclear Regulatory Commission
N_{Th}	Successive Confirmation Count Threshold
ODYSY	GE Best-Estimate Frequency Domain Stability Code
OLMCPR	Operating Limit MCPR
$OLMCPR_{Rated}$	Rated power OLMCPR
$OLMCPR_{SLO}$	Off rated OLMCPR for SLO event simulation
OLTP	Original Licensed Thermal Power
OPRM	Oscillation Power Range Monitor

Term	Definition
Option II	Stability Detect and Suppress LTS for BWR/2
Option III	Stability OPRM-Based Detect and Suppress LTS, Relying on the PBDA, ABA, and GRA for Detection
PANACEA	GE BWR Core Simulator
PBA	Period Based Algorithm
PBDA	Period Based Detection Algorithm
PFR	Partial Flow Reduction
P_i^j	Last recorded peak of the normalized signal of the i^{th} OPRM cell for the j^{th} OPRM channel
PIRT	Phenomena Identification and Ranking Table
PHE	Peak Hot Excess
PWR	Pressurized Water Reactor
P_1	GRA First Cycle Peak
RAI	NRC Request for Additional Information
RPF	Radial Peaking Factor
RPS	Reactor Protection System
RPT	Recirculation Pump Trip
SCC	Successive Confirmation Count
SLMCPR	Safety Limit MCPR
SLO	Single Loop Operation
S_{AD}	Amplitude Discriminator Setpoint
S_{CD}^{Max}	Allowable CD setpoint upper bound
S_{max}	ABA Amplitude Trip Setpoint
S_n	Filtered OPRM cell signal
S_P	PBDA Amplitude Setpoint
S_{Th}^i	OPRM Instability Threshold Flag of i^{th} OPRM cell
S_{CD}^j	j^{th} OPRM Channel CD setpoint
S_1, S_2	ABA and GRA Amplitude Threshold Setpoints
S_3	GRA Trip Setpoint
TLO	Two Loop Operation

Term	**Definition**
TMIN	Minimum Stable Film Boiling Temperature
TRACG	Transient Reactor Analysis Code (GE proprietary version)
T_{FW}	Feedwater temperature
T_{max}	PBA Time Period Upper Limit
T_{min}	PBA Time Period Lower Limit
T_1, T_2	ABA and GRA Time Windows
UGE	Unapproved GE
UNGE	Unapproved non-GE
1-D	One Dimensional
1P	Single Phase Pressure Drop
2P	Two Phase Pressure Drop
1RPT	Single Recirculation Pump Trip
2RPT	Two Recirculation Pumps Trip
3-D	Three Dimensional

1.0 INTRODUCTION

1.1 BACKGROUND

Under certain conditions, boiling water reactors (BWRs) may be susceptible to coupled neutronic/thermal-hydraulic instabilities. These instabilities are characterized by periodic power and flow oscillations and are the result of density waves (i.e., regions of highly voided coolant periodically sweeping through the core). If the flow and power oscillations become large enough, and the density waves contain a sufficiently high void fraction, the fuel cladding integrity safety limit could be challenged.

The DSS-CD solution consists of hardware and software that provide for reliable, automatic detection and suppression of stability related power oscillations. It is designed to identify the power oscillation upon inception and initiate control rod insertion to terminate the oscillations prior to any significant amplitude growth. The combination of hardware, software, and system setpoints provides protection against violation of the Safety Limit Minimum Critical Power Ratio (SLMCPR) for anticipated oscillations. Thus, compliance with General Design Criteria (GDC) 10 and 12 of 10CFR50, Appendix A is accomplished via an automatic action.

The DSS-CD is based on the same hardware design as Option III, which is described in References 1 through 3. However, it introduces an enhanced detection algorithm that detects the inception of power oscillations and generates an earlier power suppression trip signal exclusively based on successive period confirmation recognition. The DSS-CD is designed to provide adequate automatic SLMCPR protection for anticipated reactor instability events. The existing Option III algorithms are retained (with generic setpoints) to provide defense-in-depth protection for unanticipated reactor instability events.

This report provides a generic licensing basis for DSS-CD applications to GE BWR/3-6 product lines, GE14 and earlier GE fuel designs and operating envelopes up to and including Extended Power Uprate (EPU) and Maximum Extended Load Line Limit Analysis Plus (MELLLA+).

Specific hardware/software designs are not addressed in this report and, if necessary, will be submitted separately for Nuclear Regulatory Commission (NRC) approval.

1.2 PURPOSE

This report provides the licensing basis and methodology to demonstrate the adequacy of the DSS-CD solution. Section 2.0 describes the solution design philosophy, including the licensing and defense-in-depth protection approach. Section 3.0 provides a detailed description of the key solution elements, including the licensing and defense-in-depth oscillation detection algorithms. Section 4.0 describes the solution's licensing basis. Section 5.0 describes the analytical and plant data qualifications of the solution detection algorithms. Section 6.0 describes the plant specific confirmation process. Section 7.0 describes the backup stability protection feature to be employed in the unlikely event the DSS-CD licensing basis algorithm cannot be demonstrated to provide its intended SLMCPR protection. Section 8.0 discusses the effect on Technical Specifications and Bases for implementation of DSS-CD.

1.3 OVERVIEW

The licensing basis described in this report demonstrates on a generic basis that the DSS-CD features reliably detect and suppress anticipated stability related power oscillations. This provides a high degree of confidence that the SLMCPR is not violated, thus satisfying the requirements of GDC 10 and 12. The detection algorithm used for this purpose is termed the Confirmation Density Algorithm (CDA). The CDA monitors closely spaced groups of Local Power Range Monitor (LPRM) detectors to detect periodic behavior typical of reactor instability events. The CDA initiates a trip signal upon confirmation that an instability signal signature exists for a specified minimum number of LPRM groups.

The DSS-CD licensing basis consists of two major components:

a. An efficient oscillation detection algorithm, the CDA, providing an early trip signal following instability inception prior to any significant oscillation amplitude growth and MCPR degradation, and

b. A set of integrated Transient Reactor Analysis Code (TRACG) event simulations for reasonably limiting anticipated events that confirm the limited effect on the MCPR performance within the stated applicability range.

To provide defense in depth, the DSS-CD solution includes additional detection algorithms that are not credited in the licensing basis but provide additional protection against unanticipated oscillations. The DSS-CD defense-in-depth detection algorithms are:

a. Period Based Detection Algorithm (PBDA),

b. Amplitude Based Algorithm (ABA), and

c. Growth Rate Algorithm (GRA).

The PBDA provides the licensing basis protection and the ABA and GRA provide the defense-in-depth protection for LTS Option III (Reference 3). These algorithms are capable of initiating a trip signal to limit the size of an oscillation. Because these detection algorithms are not part of the DSS-CD licensing basis, no Technical Specification actions are required if any of these defense-in-depth algorithms are not operable.

This report also provides a description of Backup Stability Protection (BSP) approaches that may be used when the DSS-CD licensing basis algorithm cannot be demonstrated to provide its intended SLMCPR protection.

2.0 SOLUTION DESIGN PHILOSOPHY

2.1 DESIGN APPROACH

The design philosophy used in the development of the DSS-CD hardware/software and licensing basis is discussed in this section. The hardware design is unchanged from the Option III solution described in Reference 1. The firmware/software is modified relative to Option III to reflect the specific DSS-CD stability detection methods, which may include an upgrade to the Automatic Signal Processor card.

The DSS-CD design provides automatic detection and suppression of reactor instability events. Therefore, reliance on the operator to suppress instability events is minimized. The provision of a reliable automatic system makes the DSS-CD "operator friendly" in that protection does not rely on operator action. However, alarms are provided to alert the operator of an increase in the number of confirmed period counts so actions can be taken to avoid a reactor scram.

As described in Reference 3, a closely spaced group of LPRMs (1 to 8 LPRM detectors) is termed an Oscillation Power Range Monitor (OPRM) cell. Each of four independent OPRM channels consists of many OPRM cells distributed throughout the core so that each channel provides monitoring of the entire core. Thus, the system is fully capable of detecting both core wide and regional modes of oscillation. The system is "robust" in that it provides protection despite LPRM failures, OPRM cell inoperability (e.g., from too few inputs), or OPRM channels being out of service.

The CDA is designed to recognize an instability and initiate control rod insertion before the power oscillations increase much above the noise level. Defense-in-depth is provided by the LTS Option III detection algorithms, which are retained in the DSS-CD. These three algorithms examine aspects of the oscillation (local oscillation period, oscillation amplitude and oscillation growth rate) that may be present for oscillations that are not anticipated and are, therefore, not part of the DSS-CD licensing basis.

The CDA instability detection method and the MCPR performance confirmation analyses presented in this report provide a high confidence that the SLMCPR is not violated for anticipated oscillations, while minimizing the possibility of non-stability related scrams. The CDA capability of early detection and suppression of instability events is achieved by reliance on the successive confirmation period element of the PBDA. DSS-CD eliminates the reliance on the PBDA amplitude setpoint, which is included in the licensing basis of Option III. It introduces instead a fixed low amplitude OPRM signal discriminator, just above the OPRM signal noise level. As a result, instability suppression occurs prior to any significant growth of oscillation amplitude for anticipated instability events.

The DSS-CD solution introduces a number of changes relative to the Option III solution. In addition, it introduces a number of modifications and restrictions to the successive confirmation period element of the PBDA to improve its ability for early recognition of reactor oscillations. These changes only affect the system software/firmware, and therefore, may be able to be implemented on-line.

To ensure adequate implementation of the DSS-CD solution and to avoid unnecessary spurious reactor scrams, the system may be checked while operable but not armed for the first reactor startup to power operation and controlled shutdown following DSS-CD implementation. During this initial system demonstration, proper alarm setpoint selection should be accomplished. In addition, system performance during normal operational maneuvers may be checked. For example, the system capability to accommodate the residual oscillatory behavior following a recirculation pump upshift/restart without generating an alarm or trip signal should be assessed. During this system check out period, reactor instability protection is provided by the backup stability protection (BSP), described in Section 7.0.

The instability suppression by the DSS-CD for high growth instability events occurs within a few full oscillation periods from the time the instability is sensed by the PBA. Because the solution does not rely on oscillation growth to a specified high amplitude setpoint, suppression occurs within a short time from oscillation inception or close to the low amplitude OPRM signal discriminator and significant margin to the SLMCPR is provided. This inherent MCPR margin permits other elements of the solution's licensing basis to be demonstrated on a conservative basis, thereby simplifying the required evaluations.

In addition, conservatism is introduced in the design philosophy by selecting the SLMCPR to demonstrate protection of fuel cladding integrity for anticipated stability events. The SLMCPR is a conservative limit for this application because the fuel and clad responses to stability related oscillations are relatively mild even if the critical power ratio falls below the SLMCPR. The DSS-CD initiated control rod insertion assures that the hot bundle only experiences a few oscillations prior to scram. If a fuel rod actually experienced boiling transition, the cyclic nature of the event would result in clad rewet approximately every two seconds. A few oscillations in which the clad rewets would result in a negligible cladding temperature transient. This has been demonstrated in the assessment of Reference 4, showing that, as long as the clad rewets between cycles, the clad temperature increase is typically less than 100°F for oscillations up to 200% of rated power. Therefore, use of the SLMCPR as the acceptance criterion is conservative in protecting the fuel.

2.2 LICENSING COMPLIANCE

The DSS-CD solution and related licensing basis were developed to comply with the requirements of 10CFR50, Appendix A, "General Design Criteria for Nuclear Power Plants". The Appendix A criteria related to stability are Criteria 10 and 12.

Criterion 10 (Reactor Design) requires that:

> "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 exceeded during any condition of normal operation, including the effects of anticipated operational occurrences."

Criterion 12 (Suppression of Reactor Power Oscillations) requires that:

> "The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding

specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed."

The DSS-CD hardware and software are designed to reliably and readily detect and suppress both core wide and regional mode oscillations prior to violating the SLMCPR for anticipated oscillations. The ability to trip the reactor is automatically enabled at power and flow conditions at which stability related oscillations are possible.

To detect all expected oscillation modes, the outputs from closely spaced LPRM detectors are combined into OPRM cell signals. Thus, small regions of the core are effectively monitored for instabilities. Multiple cells distributed throughout the core provide input to each of the OPRM channels. This ensures that the system is sensitive to all of the anticipated oscillation modes, and also provides substantial redundancy for the input signals and accommodates out of service or failed LPRMs. A number of LPRM-to-OPRM cell assignments (i.e., number and location of the LPRMs that comprise the OPRM cells) are possible within the constraints of the OPRM definition given in Reference 1, as shown in Reference 3. There are no required changes in OPRM cell assignments from Option III to DSS-CD.

The DSS-CD licensing basis is designed to ensure that the system and setpoints result in suppression of oscillations before the SLMCPR is violated for anticipated instability events. In this context, anticipated oscillations are those which, based on both experience and analytical simulations, might be expected to occur in a reactor.

Anticipated instability events are defined to include core wide and regional mode oscillations with full core participation at reasonably limiting conditions and core designs. These events occur as a result of anticipated transients or normal operational maneuvers. All other instability events are considered unanticipated, including higher instability modes and limited core region participation (e.g., single channel oscillations). Unanticipated instability events occur as a result of unanticipated events or unplanned operator actions.

Protection against violating the SLMCPR for anticipated instability events is achieved solely by use of the CDA. No credit is taken for the other three algorithms that are provided as defense-in-depth protection against unanticipated oscillations.

Anticipated instability events are expected to gradually increase in amplitude and approach a limit cycle. The period of these oscillations becomes relatively constant (i.e., detectable) prior to the oscillation amplitude significantly exceeding the noise level, which allows early detection by the CDA. This is consistent with the observed behavior of actual plant instability events such as LaSalle-2 and Columbia and is consistent with the results of analytical simulations.

The licensing basis described in this report provides a high degree of confidence that power oscillations are terminated at relatively low amplitude by the DSS-CD solution, prior to any significant MCPR degradation, and therefore, obviates SLMCPR violations for anticipated instability events. Thus, the DSS-CD solution complies with GDC 10 and 12. The DSS-CD solution enhances overall plant safety by providing reliable, automatic oscillation detection and suppression function while avoiding unnecessary scrams.

3.0 SOLUTION DESCRIPTION

This section provides a description of the major aspects of the DSS-CD solution. Some elements of the solution common to LTS Option III are contained in References 1 and 2. Where there are common elements, the description provided in this document is applicable to the DSS-CD solution. The arrangement of LPRM detectors into OPRM cells is discussed in Reference 3, and is summarized herein. The CDA and defense-in-depth algorithms are described in this section along with their key setpoints.

3.1 SYSTEM FUNCTION

The DSS-CD solution consists of hardware and software designed to reliably detect and suppress stability related power oscillations. The principal inputs to the system are the signals from a large number of LPRM detectors via the OPRM cell grouping. The signals are filtered, processed, and evaluated for evidence of stability related oscillations. If sufficient evidence exists that the reactor is experiencing unstable operation, a reactor scram is initiated by the Reactor Protection System (RPS).

The key function of the system is to automatically suppress stability related power oscillations to provide a high confidence that the SLMCPR is not violated for anticipated oscillations.

The DSS-CD solution includes four separate algorithms for detecting stability related oscillations:

- Confirmation Density Algorithm (CDA),
- Period Based Detection Algorithm (PBDA),
- Amplitude Based Algorithm (ABA), and
- Growth Rate Algorithm (GRA).

All four algorithms perform calculations on each OPRM cell signal to determine if a trip is required. An illustration of the time of trip condition for each of these oscillation detection algorithms for a growing oscillation OPRM cell signal is depicted in Figure 3-1. The ability to trip the reactor is automatically enabled at power and flow conditions potentially susceptible to power oscillations. The trip enabled region is termed the Armed Region.

The PBDA, ABA and GRA detection algorithms provide the protection basis for LTS Option III, (Reference 3). They are retained in DSS-CD as defense-in-depth algorithms and are not needed to ensure compliance with the SLMCPR. Therefore, they are not part of the licensing basis for the DSS-CD solution, which is accomplished solely by the CDA. The PBDA, ABA and GRA offer defense-in-depth by providing protection for unanticipated instability events.

3.2 System Input and LPRM Assignment

The basic input unit of the DSS-CD system is the OPRM cell. Reference 3 specifies that the OPRM cell consists of 1 to 8 closely spaced LPRM detectors. The signals from the individual LPRM detectors in a cell are averaged to produce the OPRM cell signal. For the DSS-CD solution the maximum number of LPRM detectors per OPRM cell is limited to 4. This limitation is introduced consistent with the solution setpoint determination, discussed in Section 3.3.1.4, and existing Option III plant-specific implementation designs.

The cell signal is filtered to remove noise components with frequencies above the range of stability related power oscillations. This is accomplished by a second order Butterworth filter with a cutoff frequency of 1.0 Hz (referred to as the "conditioning" filter), or equivalent. The conditioned signal is filtered again using a second order Butterworth filter with a shorter cutoff frequency of 1/6 Hz, or equivalent, to produce a time-averaged value. The conditioned and time-averaged signals are used by the four algorithms to detect reactor instabilities.

The assignment of LPRM detectors to specific OPRM cells can affect the system's ability to detect an oscillation. For example, a large number of detectors in a cell tends to reduce sensitivity to an oscillation due to the averaging of signals that are slightly out of phase with each other. Conversely, analytical results show that single LPRM cells are the most sensitive. Most plants are expected to use two to four LPRMs per cell to balance OPRM cell responsiveness and spurious trip considerations. Examples of possible LPRM to OPRM cell assignments are shown in Appendix D of Reference 3. The DSS-CD solution does not add new requirements to the

LPRM to OPRM cell assignment other than the maximum limit of 4 LPRMs per OPRM cell constraint and the existing plant-specific cell assignments are acceptable.

Each OPRM cell is permanently assigned to an OPRM channel and a RPS trip channel (e.g., 1A, 2A, 1B, or 2B). If a trip condition is met for an OPRM channel, then the corresponding RPS channel trips. A reactor scram occurs when the necessary combination of channel trips occurs. The DSS-CD solution does not add new requirements to the RPS logic and the existing plant-specific RPS logic is acceptable. For example, Figure 3-2 illustrates "one-out-of-two-taken-twice" RPS logic, where a reactor trip occurs on any of the following channel trips:

1A & 2A,

1A & 2B,

1B & 2A, and

1B & 2B.

3.3 LICENSING BASIS DETECTION ALGORITHM

The CDA provides the licensing basis protection for the DSS-CD solution. The design of the licensing basis algorithm provides automatic action to limit the size of the oscillations of anticipated events, thereby preventing SLMCPR violation.

3.3.1 Confirmation Density Algorithm

The CDA generates a reactor trip signal upon sensing the threshold of coupled neutronic/thermal-hydraulic instability just above the OPRM signal noise level. By suppressing oscillations at the instability threshold, where the reactor response is becoming coherent but not yet resulted in the growth of power oscillations with significant amplitudes, reliance on complex modeling of reactor trip setpoints based on transient MCPR behavior is negated.

The CDA utilizes the Period Based Algorithm (PBA), which is designed to recognize periodic oscillatory behavior in LPRM or OPRM cell signals (referred to herein as OPRM cell signals). The PBA is that portion of the PBDA that is associated with oscillation period recognition. The PBA is described in Section 3.4.1. The PBA application in support of the CDA requires certain modifications and restrictions relative to the Option III application. Those PBA modifications and restrictions are described in Section 3.4.1.1 and associated qualifications are described in Section 5.0. The PBA modifications and restrictions are applied for both the CDA and PBDA by the DSS-CD solution. In addition, the CDA employs a low amplitude OPRM signal discriminator to minimize unnecessary spurious reactor scrams for neutron flux oscillations at or close to the OPRM signal noise level.

The CDA identifies a Confirmation Density (CD), which is the fraction of operable OPRM cells in an OPRM channel that reach a target successive oscillation period confirmation count. When the CD exceeds a preset number of OPRM cells and when any of the confirming OPRM cell signals reaches or exceeds the amplitude discriminator setpoint, an OPRM channel trip signal is generated by the CDA. A reactor trip is generated when multiple channel trips are generated, consistent with the RPS logic design. By monitoring many OPRM cells for multiple successive oscillation period confirmations, the CDA can reliably and efficiently detect the transition to coherent core response, which is characteristic of a reactor at the threshold of instability.

In certain situations, periodic perturbations can be introduced into the thermal-hydraulic behavior of the reactor system (e.g., from control system feedback). These perturbations can potentially drive prolonged neutron flux oscillations within a frequency range expected for reactor instability. The presence of these oscillations is recognized by the CDA as reactor instability, independent of the actual stability of the reactor. Therefore, reactors that exhibit prolonged neutron flux oscillations that lie within the characteristic frequency range, but are not associated with coupled neutronic/thermal-hydraulic instability, are susceptible to spurious scrams from the CDA instability detection method. For reactors that exhibit these prolonged neutron flux oscillations at the OPRM signal noise level, SLMCPR protection can be reliably maintained without increased susceptibility to spurious scrams by inclusion of the CDA signal amplitude discriminator. In cases when the CDA signal amplitude discriminator cannot adequately address these prolonged neutron flux oscillations, the plant may be susceptible to spurious scrams. In these situations, a higher signal amplitude discriminator setpoint may be justified or the CDA may be substituted with a different system for detecting the approach to core instability.

Qualification of any alternatives or substitutes to the CDA is beyond the scope of the generic DSS-CD methodology, and requires application-specific resolution, review and approval.

3.3.1.1 Introduction

The power oscillation Confirmation Density concept is predicated on the thermal-hydraulic behavior of a reactor under three distinctly different stability regimes. These regimes are stable reactor states, reactor instability threshold, and unstable reactor states.

A stable reactor has weak neutronic and thermal-hydraulic coupling, and normally exhibits small, random deviations from the steady-state neutron flux conditions. The response of a stable reactor to global noise perturbations quickly becomes incoherent. Either the response rapidly decays to the background noise level due to the stable core conditions, or subsequent unrelated perturbations disturb the natural decay characteristics. This characteristic behavior of a stable reactor inhibits the generation of many successive oscillation period confirmations, permitting the PBA to discriminate a stable reactor response from an unstable response.

At the threshold of instability, the reactor behavior is characterized by increasing neutronic and thermal-hydraulic coupling. This results in a coherent reactor response to global noise perturbations that is observable throughout the core. This phenomenon of coherent response is independent of the oscillation mode that eventually characterizes each instability event. As the core approaches an unstable state, most OPRM cells detect a periodic oscillatory response. This qualitative change in core behavior at the instability threshold results in a non-linear increase in the successive confirmation count that the PBA identifies in OPRM signals. At the threshold of instability, many OPRM cells simultaneously display oscillatory behavior due to the increased core coupling.

As a result of anticipated instability precursors, the reactor does not instantaneously transition to large amplitude neutron flux oscillations that mark core response beyond the instability inception. The characteristics of a reactor at the threshold of instability exist for a sufficient time to allow the PBA to detect the threshold condition. Specifically, the fraction of operable OPRM cells that exhibit a well-developed oscillatory signature increases from zero, before the instability threshold is reached, to a theoretical value of unity at the inception of instability. The PBA can therefore detect a significant number of successive period confirmations before the instability results in the growth in flux oscillation amplitude toward large, observable power oscillations that characterize an unstable reactor and threaten the SLMCPR.

These global characteristics of the coupled neutronic and thermal-hydraulic response to changes in core stability form the basis for the CDA methodology. Specifically, the CDA is able to recognize the instability threshold based upon the presence of multiple period confirmations from many OPRM cells. Following recognition of this condition, the CDA provides automatic protection of the fuel SLMCPR by generating a reactor trip signal prior to any significant growth in power oscillation amplitude.

The CDA methodology includes a low OPRM signal amplitude discriminator close to the typical OPRM cell signal noise levels. It avoids, however, the detailed characterization of MCPR performance as a function of growing power oscillations up to a high fixed amplitude setpoint, based on local neutron noise characteristics sensed by a few OPRM cells. As a result, the CDA methodology remains simple. In addition, the neutron noise based CD is expected to remain at zero until the reactor is at the instability threshold, at which time it rapidly approaches unity. This bi-stable behavior of the CDA eliminates the possibility of generating spurious trip signals for stable conditions based on the thermal-hydraulic behavior of the reactor.

3.3.1.2 Algorithm Basis

The CDA detects the presence of oscillatory behavior in the OPRM signal using the PBA. The PBA successive oscillation period confirmation count, for each OPRM cell exhibiting oscillatory behavior, increases in a highly non-linear manner at the instability threshold. In addition, the response of the core to global noise perturbations is observable over larger areas, causing many OPRM cells to exhibit oscillatory behavior.

Therefore, as the reactor decay ratio approaches unity, and the reactor reaches the instability threshold, both the successive confirmation counts of individual OPRM cells and the number of OPRM cells generating multiple successive confirmation counts grow in an accelerated manner.

A direct result of these qualitative changes in core response at the instability threshold is a non-linear increase in the fraction of OPRM cells reaching a target confirmation count, termed Successive Confirmation Count Threshold (N_{Th}). This fraction, which is the fraction of operable OPRM cells in an OPRM channel that exhibits an oscillatory response at or above N_{Th}, is defined to be the Confirmation Density (CD).

The theoretical relationship between CD and reactor Decay Ratio (DR) is illustrated in Figure 3-3. The shape of the relationship assumes that the PBA is perfectly able to discern the oscillatory behavior of all OPRM cells, regardless of the oscillation mode. However, even with a perfect PBA, the relationship between the CD and DR at the instability threshold is not exact. The reactor conditions, growth rate, and the PBA system parameters are examples of elements that may affect the specific shape of this relationship.

The precise shape of the instability threshold band does not affect the qualitative transition in the CD to DR relationship between the stable reactor, instability threshold, and instability inception conditions. Figure 3-3 demonstrates the utility of the CD approach to provide automatic protection of the fuel SLMCPR from reactor instability. During stable reactor operations, decay ratios are typically low ($DR < 0.4$), with occasional increases into the moderate range ($0.4 < DR < 0.7$). For these reactor conditions, individual OPRM cell confirmation counts are not likely to reach the successive confirmation count threshold, and therefore the CD remains practically at zero. However, as soon as the instability threshold is approached ($DR \cong 1.0$), the CD rapidly increases. This bi-stable characteristic of the CD, where the value remains at zero except at the instability threshold, when it rapidly transitions to unity, provides excellent discrimination between stable and unstable operations. As a result, the CDA avoids spurious trips, but can generate a reactor trip signal before oscillations develop significant magnitude.

Some of the operable OPRM cells may exhibit oscillation signatures incompatible with the PBA due to interference from neutron flux originating from areas of the core that are oscillating out-of-phase. This effect is particularly prominent near the axis of symmetry during first order regional mode oscillations. As a result, the maximum CD that is achievable in practice is less than one, as illustrated in Figure 3-4.

A CD setpoint (S^j_{CD}) is established for each OPRM channel, and defined to be the CD value for which a trip signal is generated. The setpoint is selected to ensure that an adequate number of OPRM cells exceed the successive confirmation count threshold, and that a sufficiently representative sample of OPRM cells is available for evaluation by the detection algorithm.

To minimize unnecessary spurious scrams not related to instability events, the CDA includes a low amplitude discriminator setpoint. Its purpose is to prevent a trip signal for situations when an oscillatory signature develops, which may be interpreted by the CDA as an instability event, but is occurring at a low amplitude and does not exhibit any significant amplitude growth. These situations may be associated with low amplitude, undeveloped instability events or reactor perturbation driven oscillations that are not related to coupled neutronic/thermal-hydraulic instability events. An Amplitude Discriminator state (AD_j) is established for each OPRM channel. An OPRM channel trip signal is generated when both the confirmation density and amplitude discriminator trip conditions are met.

3.3.1.3 Algorithm Description

An OPRM cell instability threshold flag, S^i_{Th}, is introduced to indicate the status of the successive confirmation count, N_i, of the i^{th} operable OPRM cell relative to the successive confirmation count threshold (N_{Th}). It is defined as:

$$S^i_{Th} = \begin{cases} 0 & N_i < N_{Th} \\ 1 & N_i \geq N_{Th} \end{cases}$$

Whenever the successive confirmation count, N_i, for the i^{th} OPRM cell is reset to zero, S^i_{Th} is also reset to zero.

The j^{th} OPRM channel confirmation density, CD_j, is the fraction of OPRM cells exhibiting successive confirmation counts that are at or above N_{Th}, and is expressed as:

[[ ]]

where M^{j}_{OP} is the number of operable OPRM cells in the j^{th} OPRM channel and M^{j}_{RS} is the number of responsive OPRM cells in the j^{th} OPRM channel.

A certain number of OPRM cells may become inoperable during the course of an operating cycle. The confirmation density is based on operable OPRM cells only. Therefore, inoperable OPRM cells are explicitly addressed by the CD setpoint definition.

[[

]]

An amplitude discriminator state, AD_j, is introduced to characterize the amplitude of all OPRM cells with confirmation count at or above N_{Th} (M^j_{CD}), corresponding to the j[th] OPRM channel, relative to the amplitude discriminator setpoint (S_{AD}). It is defined as:

[[

]]

The reactor instability threshold is identified by each OPRM channel and the j[th] channel trip signal is generated when both, the j[th] channel CD setpoint, S^j_{CD}, is reached and the j[th] channel amplitude discriminator state, AD_j, is enabled:

$$CD_j \geq S^j_{CD} \text{ and } AD_j = 1$$

A reactor trip signal is generated consistent with the plant specific RPS system trip logic, when the required multiple channels trip signals are generated.

An alarm setpoint is included to provide an early indication of reduced stability margin.

Table 3-1 summarizes the CDA process, setpoints and basis.

Implementation of the CDA requires the determination of the following setpoints:

a. Confirmation Density Setpoint (S_{CD}),

b. Successive Confirmation Count Threshold (N_{Th}),

c. Amplitude Discriminator Setpoint (S_{AD}), and

d. Alarm setpoint,

which are addressed in the subsequent sections.

3.3.1.4 Confirmation Density Setpoint Determination

In principle, the CDA uses the CD Setpoint (S^{j}_{CD}) to determine when the CD is equal to unity, which indicates the point of instability inception. In practice, however, the CD at the instability inception cannot be precisely predicted. Various factors such as oscillation mode and the relative efficiency of the PBA when applied to OPRM cells near the oscillation axis of symmetry, which is influenced by potential signal cancellation, effectively reduce the value of the CD at the instability inception to a value less than unity. An evaluation of OPRM cells participation during power oscillations is performed to establish the CD upper and lower bounds used to determine the CD setpoint.

Based on the CD model (Figure 3-4), instability threshold conditions exist for a finite time before instability inception occurs. The qualitative differences between stable reactor conditions and conditions at instability threshold are reflected in the strongly bi-stable behavior of the CD as a function of DR, and makes discrimination of the instability threshold straightforward. As a result, the CDA can protect the SLMCPR by appropriate selection of a reactor trip setpoint based on a conservative number of OPRM cells that are indicating instability threshold conditions, rather than attempting to precisely identify the condition of instability inception. Because of the availability of a large number of operable OPRM cells for use by the CDA, a bounding approach is taken to establishing an appropriate upper bound for the CDA trip setpoint.

The allowable CD setpoint upper bound (S^{Max}_{CD}) is given by:

$$S_{CD}^{Max} = (1 - E) \times F_{CD}^{Max}$$

E is defined to be the axial loss of PBA efficiency. The maximum response fraction, F_{CD}^{Max}, is defined to be the bounding maximum fraction of OPRM cells, ignoring axial PBA inefficiencies, that reaches N_{Th} at the point of instability inception. The values of E and F_{CD}^{Max} are selected to establish a permissible maximum value for the CD Setpoint. The actual setpoint must be selected at or below this value to ensure proper operation of the CDA.

The neutron mean free path in highly voided core regions is comparable to the spacing between adjacent LPRMs. Therefore, during regional mode oscillations LPRMs in the top of the core can exhibit oscillatory behavior that is caused by the superposition of neutron flux originating from areas of the core on both sides of the oscillation symmetry axis. This composite signal can cause poor performance of the PBA in discriminating successive confirmation counts. As a result, E is generically set to 0.25 for OPRM cells that consist of a single LPRM, corresponding to the conservative assumption that the PBA is completely unresponsive to the D level (highest in the core) LPRMs.

For OPRM cell configurations that have more than a single LPRM per OPRM cell, one or more of the cell's LPRMs is at a level different than D. For these configurations, many of the OPRM cells do not include D level LPRMs. For those that include D level LPRMs, the OPRM cell response is typically dominated by the lower level LPRMs because the D level LPRM relative power is typically low. To maintain consistency with the conservative treatment of the single LPRM OPRM cell, E is generically set to 0.25 for all OPRM cell configurations.

The value of F_{CD}^{Max} is dependent on the mode of the power oscillations present in the core. A regional mode oscillation is conservatively selected as the limiting anticipated core behavior with respect to the CDA performance. LPRMs near the axis of symmetry can detect oscillations that are completely out of phase with the local thermal-hydraulic response. This condition is incompatible with the requirements of the PBA to discern successive confirmation counts. The size of the affected core area is governed by the neutron mean free path. Selection of a corresponding no-response zone width equivalent to 3 mean free paths on each side of the axis of symmetry provides approximately 95% attenuation of neutron flux from across the axis of symmetry, and bounds those LPRMs that may be affected by neutrons from the opposite oscillation phase. By conservatively using a small reactor design of 444 fuel assemblies, the maximum response fraction, F_{CD}^{Max}, for the assumptions described above is determined for OPRM cells with a single LPRM. Assuming an approximately even LPRM distribution in the core, a conservative estimate is established as:

$F_{CD}^{Max} = 0.70$ for single LPRM based OPRM cell

For most OPRM cells with more than a single LPRM, the selection of three mean free paths on each side of the axis of symmetry is conservative because the radial distribution of the LPRMs belonging to an OPRM cell provides a wider coverage. To maintain consistency with the conservative treatment of the single LPRM OPRM cell, F_{CD}^{Max} is generically set to 0.70 for all OPRM cells configurations.

The value of S_{CD}^{Max} is now determined based on the conservative estimates of the E and F_{CD}^{Max} values for all OPRM cell configurations:

$$S_{CD}^{Max} = (1 - 0.25) \times 0.70$$

or,

$$S_{CD}^{Max} \approx 0.5$$

The process of establishing the above estimate for the CD setpoint upper bound is illustrated in Figure 3-5. This value places a permissible upper bound on the CD Setpoint, S_{CD}^{j}, that is consistent with the requirement that the CDA generate a trip signal prior to or at the inception of reactor instability.

The estimate of F_{CD}^{Max} was confirmed using a PANACEA predicted response for an example BWR first order harmonic. The first harmonic contour from the PANACEA case is shown in Figure 3-6. Inside each fuel rectangle is the axial flux distribution for the corresponding bundle.

The bottom of the core is on the left of each rectangle and the top of the core is on the right. The zero flux level is represented by a horizontal line through the center of the rectangle. In this case, first harmonic flux is positive in the lower left half and negative in the upper right half. Except for those fuel channels close to the harmonic axis, running from the northwest to southeast, the majority of the remaining fuel channels participate in the regional oscillations. The F_{CD}^{Max} value estimate based on the first harmonic contour is 0.8, which confirms the above estimate for all OPRM cell configurations.

A permissible minimum confirmation density setpoint, S_{CD}^{Min}, can also be established for S_{CD}^{j}. The minimum permissible value is not dictated by safety considerations. Instead, as S_{CD}^{j} decreases, the required number of OPRM cells reaching N_{Th} needed to generate a reactor trip signal becomes smaller. As a result, the CDA may become more sensitive to the characteristics of the instability threshold specific to a particular event and could potentially lead to a premature generation of reactor trip signals. To conservatively preclude this type of spurious actuation, a minimum number of OPRM cells are required to reach N_{Th} before the CDA generates RPS channel and reactor trip signals.

BWR experience to date has demonstrated that it is unlikely that the N_{Th} setpoint be exceeded for any OPRM cell during stable reactor operation in the Armed Region, where the system is armed. Moreover, for these conditions, it is not credible that multiple OPRM cells exceed the N_{Th} setpoint simultaneously. For certain OPRM cell configurations selected LPRMs may be grouped to 4 different OPRM cells. Therefore, a postulated dominating spurious LPRM oscillatory signature may affect the behavior of 4 different OPRM cells. To reduce the potential for spurious trip signals during stable reactor operation in the Armed Region, [[

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For plants requiring at least two LPRMs to maintain OPRM operability, the possible reduction in the number of responsive OPRM cells by M^{j}_{DL} can be eliminated by implementing LPRM to OPRM cell assignments that include no more than one D level LPRM in each OPRM cell. For these configurations, OPRM cells with exclusive input from D level LPRMs include only a single operable LPRM, and are therefore declared inoperable. Example LPRM to OPRM cell assignments are shown in Appendix D of Reference 3.

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3.3.1.5 Successive Confirmation Count Threshold Determination

The CDA utilizes the successive confirmation count threshold (N_{Th}) to discriminate the stability characteristics of individual OPRM cell successive confirmation counts generated by the PBA. The choice of N_{Th} is based on two considerations.

[[

]] Because the reactor is not anticipated to instantaneously transition to unstable, growing power oscillations, this CDA response time provides adequate protection of fuel SLMCPR for anticipated instability events.

3.3.1.6 Amplitude Discriminator Setpoint Determination

The CDA utilizes the amplitude discriminator setpoint (S_{AD}) to prevent CDA-generated trip signals at the naturally occurring OPRM signal noise level. The choice of S_{AD} is based on two considerations.

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3.3.1.7 Single Loop Operation

Application of the TLO CDA setpoints to SLO may result, under certain operating conditions, in excessive unnecessary spurious scrams. [[

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3.3.1.8 Alarm Setpoint Determination

The CDA provides automatic indication of reductions in stability margin to alert the operator of possible approach to the instability threshold when operating inside the Armed Region. With an appropriately selected alarm setpoint, sufficient time for manual operator action may exist for transients that cause a gradual erosion of reactor stability margin from stable reactor operating conditions. This CDA alarm capability is provided in addition to the alarm being actuated upon entry into the Armed Region, which is designed to alert the operator that an entry into a region potentially susceptible to reactor instability had occurred.

The CDA alarm setpoint, N_{Al}, is selected on a plant-specific basis to ensure that no spurious alarms occur during stable plant operation. The alarm setpoint may be applied to the leading OPRM cell. The alarm occurs when the successive period confirmation count for any single OPRM cell (in any OPRM channel) reaches the CDA alarm setpoint. Alternatively, the alarm setpoint may be applied to the second confirming OPRM cell (i.e., provided a single OPRM cell exceeds N_{Al}, the alarm is generated when any additional OPRM cell in the same OPRM channel exceeds the selected alarm setpoint). The CDA alarm may be implemented with another means of stability monitoring (e.g., on-line stability predictor or monitor) to improve the capability to predict gradual changes in stability margin.

The selection of a specific alarm setpoint value and definition of the associated operator actions are operational considerations and depend on the plant-specific neutron flux noise characteristics and operational preferences and are not addressed in this report. Because the CDA alarm function has no effect on the system automatic protection capability, the choice of the plant specific alarm setpoint is optional and is not subject to any generic or plant specific requirements. Therefore, from a licensing perspective, any alarm option selection is acceptable.

The alarm function is not required during rated power operation outside the Armed Region, where the system is operable but not armed. If the alarm function is not continuously armed during operations at core flow above the Armed Region, the alarm function is automatically armed upon entry into the Armed Region.

3.3.1.9 Generic Setpoints Application

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]] Therefore, each plant-specific application for DSS-CD will include a comparison of the resulting margins to the SLMCPR and the margins presented in the DSS-CD LTR.

3.4 DEFENSE IN DEPTH ALGORITHMS

The PBDA, ABA and GRA offer defense-in-depth by providing protection for unanticipated instability events. These algorithms are not required to provide licensing basis protection for the SLMCPR within the DSS-CD solution.

The design objective for the defense-in-depth algorithms is to provide automatic action to limit the size of the oscillations of unanticipated events, thereby preventing fuel cladding damage. As demonstrated in Reference 4, power oscillations up to 200% of rated power produce a temperature transient such that no cladding failure would be expected. The defense-in-depth detection algorithms offer a high degree of assurance that fuel failure does not occur as a consequence of unanticipated stability related oscillations.

Table 3-4 lists the DSS-CD defense-in-depth algorithm recommended setpoints. The choice of setpoints for the ABA and GRA is consistent with References 1 through 3. For the PBDA, nominal setpoint values are recommended on a generic basis. These setpoints would reasonably limit the size of unanticipated stability related power oscillations. They are selected to provide early protection without significantly increasing the likelihood of a spurious scram not related to instability events. The defense-in-depth trips with the specified setpoints provide backup protection greater than that provided by the Average Power Range Monitor (APRM) high flux scram, in particular for the regional mode of oscillations. No further analysis is required to justify these setpoints.

3.4.1 Period Based Detection Algorithm

The Period Based Detection Algorithm (PBDA) is described in References 1 and 2. The PBDA utilizes the observation that LPRM noise becomes progressively more coherent during the approach to the inception of an instability event, before the amplitude becomes large. The PBDA uses a combination of period confirmation count and amplitude setpoint to determine if a trip is required. The period confirmation count portion of the PBDA is referred to as the Period Based Algorithm (PBA). It constitutes the entire algorithm with the exception of the amplitude aspect.

According to Reference 1, the PBA focuses on the periodicity of the oscillation in the approximate range from 0.3 to 0.7 Hz, or the equivalent time period limits (T_{min} and T_{max}). T_{min} and T_{max} are conservatively selected to bound the anticipated instability frequency range. The algorithm interrogates the OPRM cell signal based on a short sample time (t_i). When the time difference between successive peaks (or successive minima) in an OPRM cell signal is consistent with the time period limits, this time difference is defined as the base period, T_0. The next period (T_1) calculated between successive peaks (or minima) must be within a small time window, period tolerance ($\pm$ ε), of T_0 to produce a "confirmation" that oscillatory behavior exists. A new base period is defined as the average of all consecutively confirmed periods in that cell. Based on evaluation of plant data, as the decay ratio increases toward 1.0, the oscillation period becomes constant, resulting in many consecutive confirmations. If a successive period is not confirmed to be within the period tolerance of the base period, the period count is reset to zero and the search for a new base period is initiated. The PBA period confirmation process is illustrated in Figure 3-9.

The PBDA is programmed to identify an instability based on the occurrence of a fixed number of consecutive period confirmations, which is considered evidence of a stability related power oscillation. A trip is generated for an OPRM cell (and hence for that RPS channel) if:

1. The number of successive period confirmations exceeds its setpoint value (N_p), and
2. The relative signal exceeds a specified amplitude setpoint, S_p.

The value of S_p is set sufficiently above the noise level to minimize the likelihood of an inadvertent scram. Consequently, the PBDA generates a trip when oscillatory behavior consistent with an instability exists and the peak-to-average cell signal has increased to the trip amplitude setpoint. This balances the probability that the system trips when needed to suppress an instability event and does not trip when it is not required.

For DSS-CD, the PBDA successive period confirmations setpoint, N_p, is selected above the CDA setpoint (i.e., 15). This setpoint is representative of the higher end of the range provided in Reference 3, Appendix E. This selection is made to further reduce the likelihood of a spurious scram by the PBDA, which is appropriate since the PBDA is a DSS-CD defense in depth algorithm that is not required to demonstrate SLMCPR protection. The PBDA amplitude setpoint, S_p, is selected at 1.1 consistent with the other defense-in-depth algorithms, to provide protection at the ABA and GRA amplitude detection threshold (S_1).

References 1 and 2 define two adjustable parameters that affect period confirmations, and are used to achieve proper plant-specific system calibration, the period tolerance (ε) and the conditioning filter cutoff frequency (f_c). Based on existing experience and to ensure adequate instability detection by the PBA, these parameters' values are fixed for DSS-CD applications, and are not subject to adjustment. The assigned values for these parameters have been demonstrated to provide continuous confirmations upon transition from stable reactor operation to a growing reactor instability. Specifying the parameters' values provides assurance that the PBDA provides sufficient confirmations for a growing reactor instability.

Based on testing of the algorithm against available plant data and DSS-CD specific considerations (see below), the acceptable parameter values are specified in Table 3-5. The conditioning filter cutoff frequency value is selected at 1 Hz to ensure efficient filtering of high frequency noise components, which is critical for proper PBA functioning during the development of reactor instability events. The conditioning filter cutoff frequency has been shown to have little effect on the PBA successive confirmation count during stable operation. The period tolerance value is selected at 100 msec to ensure adequate period confirmation during the development of reactor instability events, which is supported by existing instability event experience. This value, however, may result in increased PBA successive confirmation count during stable operation, which need to be considered in the selection of the CDA alarm setpoint.

The normalized OPRM signal processed by the PBA is constructed as the ratio of the filtered input signal to the OPRM signal average. Reference 2 specifies that a typical range for the time constant associated with the signal averaging process is 5 to 7 seconds. This range provides an appropriate signal average value for steady state or quasi steady state operation. However, the averaged signal may significantly lag the input signal during a fast transient, such as a significant flow reduction event from rated power operation. Because MELLLA+ operation may result in off-rated conditions that are inherently unstable following a flow reduction event, instability may develop during the time the averaged signal is lagging and the normalized signal is inappropriately low.

To address this concern, an averaging filter cutoff frequency of 1/6 Hz (or an equivalent time constant of 0.95 seconds) is used for DSS-CD, which substantially reduces the averaged signal lag (the transition band is reduced from close to 30 seconds to approximately 5 seconds). This cutoff frequency value provides less effective averaging process during steady state operations, resulting in low amplitude residual oscillations. However, because the cutoff frequency value is sufficiently low, the average signal exhibits only insignificant amplitude variations for the signal amplitude range up to the DSS-CD PBDA amplitude setpoint. A parametric study of the normalized signal performance with the 1/6 Hz filter cutoff frequency for the detection algorithm oscillation period range (from 0.8 second to 4.0 seconds) has demonstrated that the normalized signal values are always conservative (i.e., higher) during steady state operations. Therefore, the use of the 1/6 Hz averaging cutoff frequency eliminates the concern of significant normalized signal lag following a fast flow reduction event, and ensures a conservative normalized signal value during oscillations relative to the DSS-CD PBDA amplitude setpoint.

3.4.1.1 PBA Application for CDA

A number of modifications and restrictions for the Option III PBA version (Reference 3) are required for the proper application of the PBA in the CDA. [[

]] These PBA modifications and restrictions are also used for the PBDA, [[

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Significant flow reduction events from power operation may result in operating conditions that are unstable. This is more likely for 2RPT events that initiate from the rated power and minimum flow conditions. Because the reactor state condition is rapidly changing during the 2RPT event, the ensuing oscillations are not developed instantaneously. The transition to a coherent oscillation mode involves the alignment of the entire core, which not only requires some limited duration but also may exhibit transitional effects. In particular, the oscillation frequency, and therefore, the detected period for individual channels may exhibit modulated behavior.

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The time period limits specified in Table 3-4 conservatively envelop the range of characteristic periods anticipated for all DSS-CD applications addressed by this report. [[

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3.4.1.2 PBA Signal Sampling and Resolution for DSS-CD

The PBA evaluates a discrete representation of the OPRM cell input signal that depends on the signal sample rate. The signal sample rate is selected to ensure that signal periods, which fall within the specified algorithm frequency range, contain a large number of samples. Discretization of the input signal creates the possibility of shifts in the number of time step intervals associated with a single period. For an input signal with a constant period, variations of plus or minus one time step relative to the average number of time steps per period may occur. If the selected period tolerance value is equal to the sampling time step, occasional reset of the Successive Confirmation Count (SCC) for a fully periodic signal may occur due to shifts in the time step count per period.

The base period is equal to a whole multiple of the sampling time step for each SCC. A single occurrence of a period with one less time step than the base period count reduces the base period by one time step. If the subsequent period contains one more time step than the original base period, the difference between the current period and the base period is more than one time step. As a result, the period tolerance criterion is violated when it is equal to the sampling time step and results in an erroneous SCC reset. A SCC reset also occurs with the reverse scenario, when the higher time step count per period is encountered prior to the lower count.

To ensure that a continuous SCC is generated for a periodic OPRM cell signal within the PBA range, the theoretical minimum period tolerance is related to the discretization of the OPRM cell signal by the following relationship:

$$\varepsilon = \text{Max}\,(\varepsilon_{\text{Input}},\, 2 \times \text{Signal sampling time step})$$

where $\varepsilon_{\text{Input}}$ is the PBA period tolerance selection available and ε is the resultant period tolerance.

The DSS-CD solution design requires a criterion specifying the minimum acceptable resolution of the OPRM cell signal amplitude. Appropriate selection of this criterion ensures that under all anticipated reactor conditions approaching reactor instabilities the system is capable of performing its design functions, including the identification of successive signal minima and maxima and characterization of signal period.

Reactor two recirculation loop operations in regions of the operating domain susceptible to reactor instabilities are typically associated with a nominal peak-to-average OPRM noise amplitude of 1 to 2%. This amplitude is dependent on the specific reactor conditions and may vary from plant to plant. However, the peak-to-average range is characteristic of stable reactor operation. During the approach to reactor instabilities, peak-to-average amplitudes increase from those associated with stable reactor operation amplitudes.

To ensure the system is designed with an acceptable signal amplitude resolution, the criterion specifying the minimum acceptable resolution of the OPRM cell signal peak-to-average amplitude difference is set at 1% of scale. This value represents the lower bound of typically observed peak-to-average amplitudes during stable reactor operation, and is conservative for conditions approaching reactor instabilities. Application of this criterion ensures that the system is capable of successfully identifying successive minima and maxima for periodic signals, with peak-to-average amplitude difference of 1% of scale or higher, for the full frequency range expected for reactor instabilities.

3.4.2 Amplitude Based Algorithm

The ABA is described in References 1 and 2. The value of the OPRM cell relative signal is compared at each detection time step to a threshold setpoint, S_1 (greater than 1.0). If the relative signal exceeds S_1, then the algorithm checks to determine if the relative signal decreases to a second setpoint, S_2 (less than 1.0), within a time period typical of an instability oscillation. If the signal goes below S_2 in the expected time window (T_1), then the algorithm looks for the next peak in the relative signal. Then, if the relative signal exceeds the trip setpoint, S_{max}, in the expected time window (T_2), a trip is generated for that OPRM cell (and hence for that RPS channel). Recommended values for S_1, S_2, S_{max}, T_1, and T_2 are given in Table 3-4.

3.4.3 Growth Rate Algorithm

The GRA is described in References 1 and 2. It examines OPRM cell signals for rapidly growing oscillations. As for the ABA, the value of the OPRM cell relative signal is compared at each detection time step to a threshold setpoint, S_1 (greater than 1.0). If the relative signal exceeds S_1, then the algorithm checks to determine if the relative signal decreases to a second setpoint, S_2 (less than 1.0), within a time period typical of an instability oscillation. If the signal goes below S_2 in the expected time window (T_1), then the algorithm looks for the next peak in the relative signal. A trip signal is generated by the GRA if the setpoint S_3 is exceeded in the expected time window. S_3 is calculated from the peak of the previous cycle (P_1) and the desired maximum allowable growth rate (GR_3):

$S_3 = GR_3 \times (P_1 - 1.0) + 1.0$

If the signal goes above S_1, then below S_2 in the expected time window, and then exceeds S_3 within the expected time window, a trip is generated for that OPRM cell (and hence for that RPS channel). The GRA uses the same values for S_1, S_2, T_1, and T_2 as the Amplitude Based Algorithm. Recommended values for S_1, S_2, GR_3, T_1 and T_2 are given in Table 3-4.

3.5 SYSTEM OPERABILITY

To provide its specified stability protection function, the DSS-CD system is required to be operable in Mode 1 at all times and is automatically armed inside the solution Armed Region, as described in Section 4.5. Alternatively, the DSS-CD may be required to be operable above a power level set at 5% of rated power below the lower boundary of the Armed Region defined by the MCPR monitoring threshold power level. This alternative method is acceptable since system operability is assured prior to entry into the Armed Region.

For operation outside the Armed Region, the system is disarmed to reduce the probability of spurious scrams and alarms, but maintained operable at all times. If the system licensing basis protection is not assured, a supplemental backup, as specified in the plant Technical Specifications, is required. Example backup stability protection (BSP) approaches are described in Section 7.0. Other backup approaches that are justified to provide protection similar to the BSP may also be used. Backup protection is required when the DSS-CD is bypassed.

Table 3-1 Confirmation Density Algorithm Setpoints and Basis

Process Step	Algorithm	Definition and Setpoint	Basis and Notes
Determination of OPRM cell Instability Threshold Flag (S^i_{Th}) state	$S^i_{Th} = \begin{cases} 0 & N_i < N_{Th} \\ 1 & N_i \geq N_{Th} \end{cases}$	N_i = Successive confirmation count of the i^{th} OPRM cell N_{Th}= Successive Confirmation Count Threshold [[ ]]	- OPRM cells or single LPRMs may be used - S^i_{Th} is set to 1 at signal extremum only if the confirmation count is equal or above N_{Th} - S^i_{Th} is reset on count reset for the i^{th} OPRM cell - [[ ]]
Determination of j^{th} OPRM channel Confirmation Density (CD_j)	[[ ]]	M^j_{RS} = Number of responsive OPRM cells for j^{th} OPRM channel M^j_{OP} = Number of operable OPRM cells for j^{th} OPRM channel $M^j_{RS} = M^j_{OP} - M^j_{AX} - M^j_{DL}$	- Operable OPRM cells require at least 1 or 2 operable LPRMs - [[ ]]
Determination of j^{th} OPRM channel amplitude discriminator state (AD_j)	[[ ]]	P^j_i = Last recorded peak of i^{th} OPRM cell normalized signal for j^{th} OPRM channel M^j_{CD} = Number of OPRM cells at or above N_{Th} for j^{th} OPRM channel S_{AD} = Amplitude discriminator setpoint [[ ]]	- [[-]]
Trip signal for j^{th} RPS channel by comparison with CD setpoint (S^j_{CD}) and AD state (AD_j)	$CD_j \geq S^j_{CD}$ AND $AD_j = 1$	S^j_{CD} = j^{th} channel CD setpoint [[ ]]	[[-]]
NMS trip signal	System architecture	E.g., one-out-of-two, twice	- Adheres to NMS requirements of divisional separation and redundancy
NMS alarm signal	$N_i \geq N_{Al}$	N_{Al} = Successive confirmation alarm setpoint	- Early indication of reduced stability margin - Applied to leading or second OPRM cell - Determined based on plant specific performance

Table 3-2 444 Bundle Core OPRM Channel Operability and CD Setpoint Illustration

(OPRM Map assignment per Figure 3-7 and OPRM cell operability requirement of at least one operable LPRM)

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Table 3-3 624 Bundle Core OPRM Channel Operability and CD Setpoint Illustration

(OPRM Map assignment per Figure 3-8 and OPRM cell operability requirement of at least two operable LPRMs)

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Table 3-4 Defense in Depth Algorithm Setpoints

Algorithm	**Setpoint**	**Value**
PBDA	N_P	15
PBDA	S_P	1.1
PBDA	T_{min}, T_{max}	[[ ]]
ABA, GRA	S_1	1.10
ABA, GRA	S_2	0.92
ABA	S_{max}	1.30
GRA	GR_3	1.30
ABA, GRA	T_1 (time window)	0.3 to 2.5 seconds
ABA, GRA	T_2 (time window)	0.3 to 2.5 seconds

Table 3-5 PBA Parameters

Parameter	**Value**
ε - Period Tolerance (milliseconds)	100
f_c - Conditioning Filter Cutoff Frequency (Hz)	1.0

Figure 3-1 DSS-CD Detection Algorithms Time of Trip Condition Illustration

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Figure 3-2 Example RPS Trip Logic

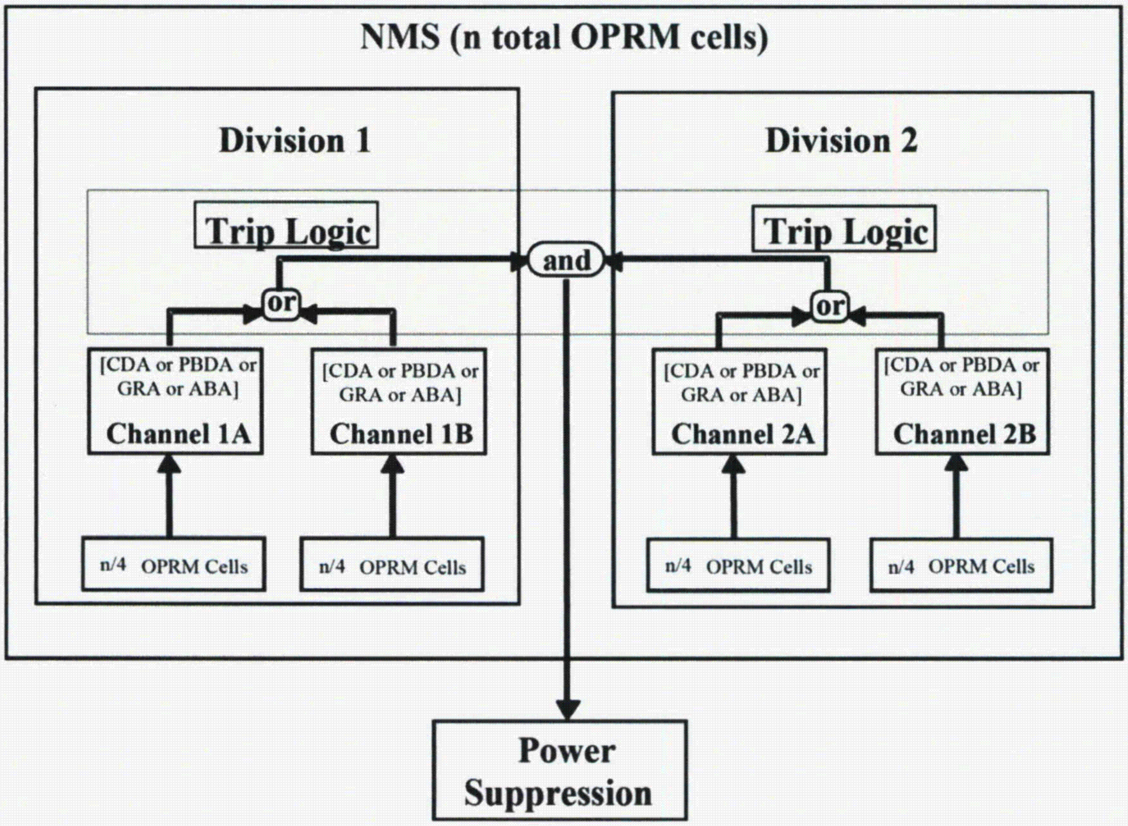


Figure 3-3 Theoretical Confirmation Density as a Function of Decay Ratio

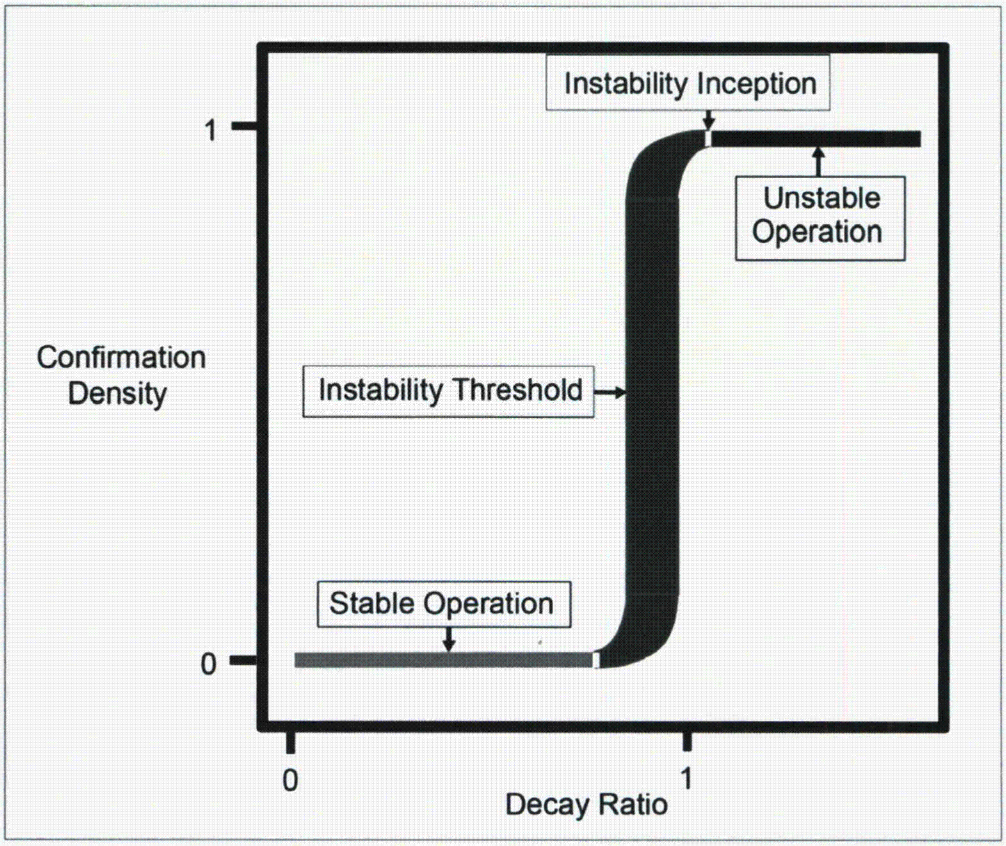


Figure 3-4 Practical Confirmation Density as a Function of Decay Ratio

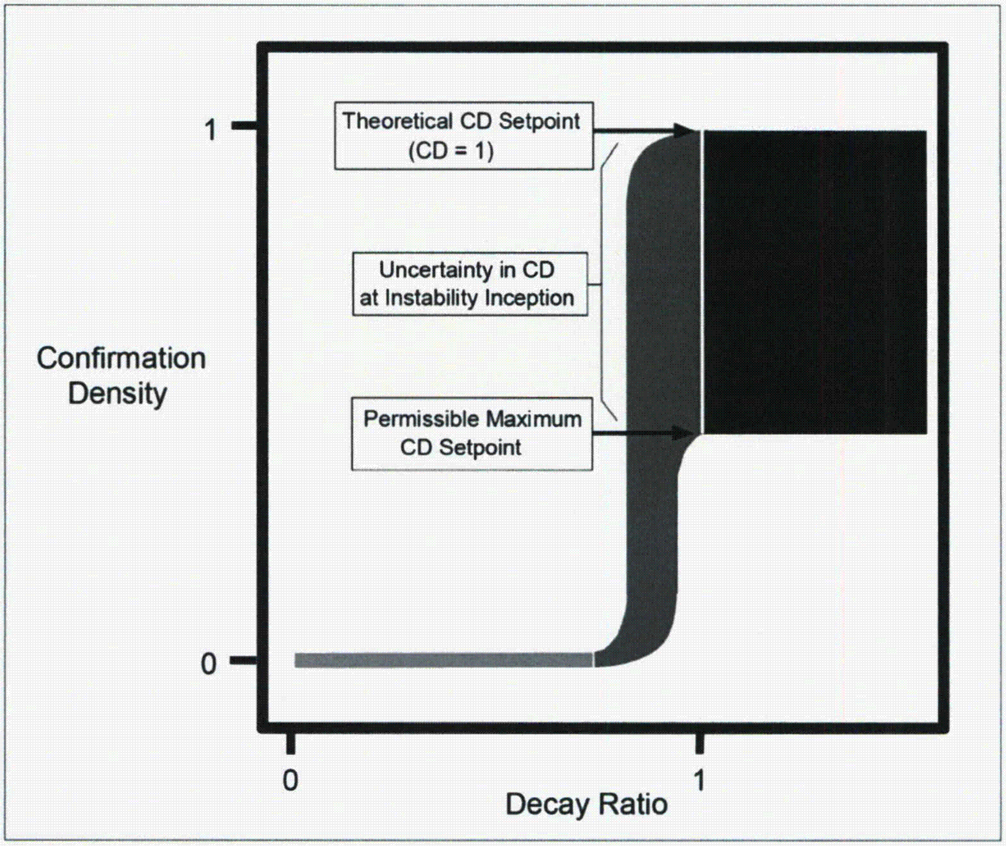


Figure 3-5 Core Volume Corresponding to CD Upper Bound

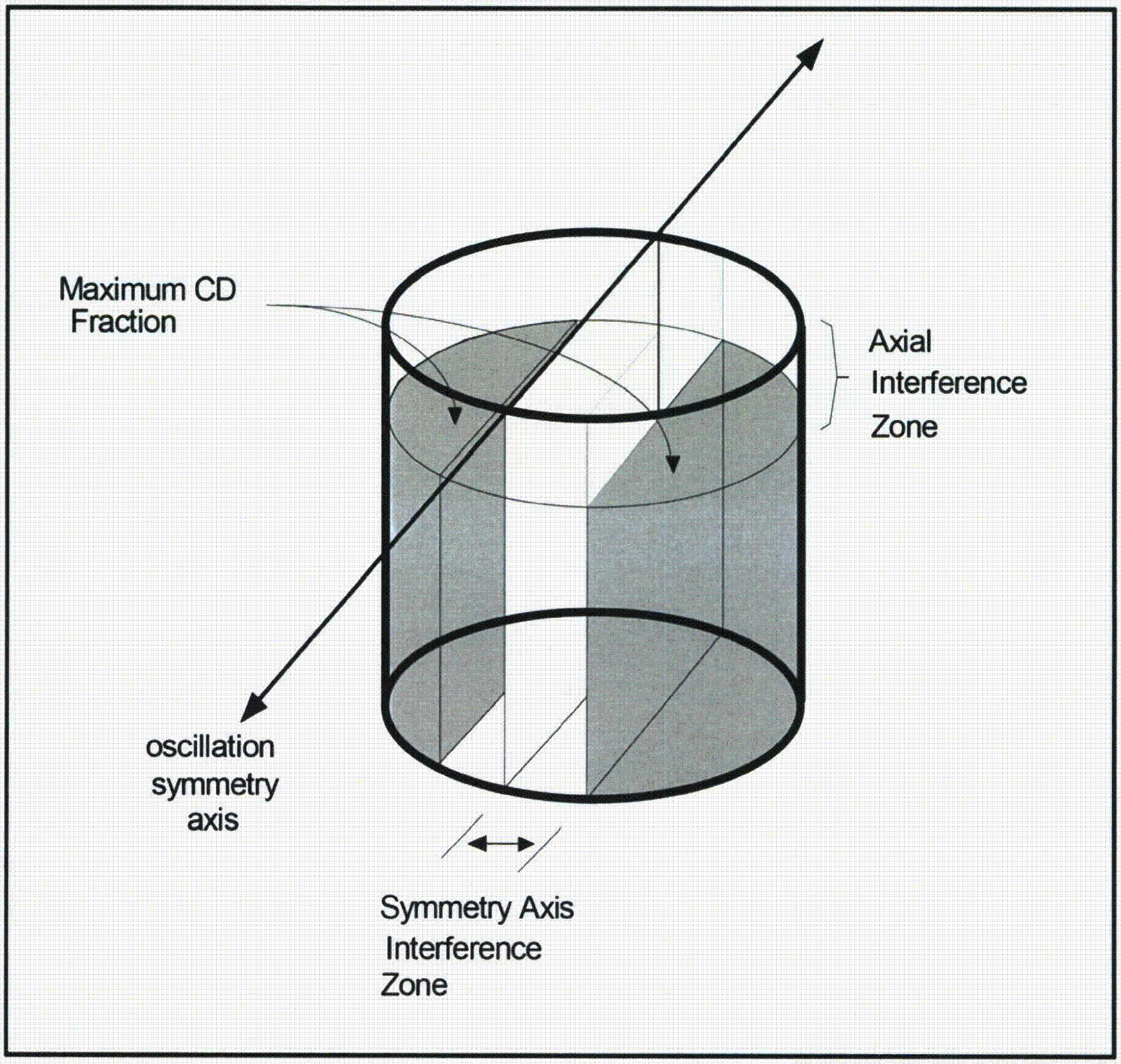


Figure 3-6 PANACEA Contour for a Typical BWR First Order Harmonic

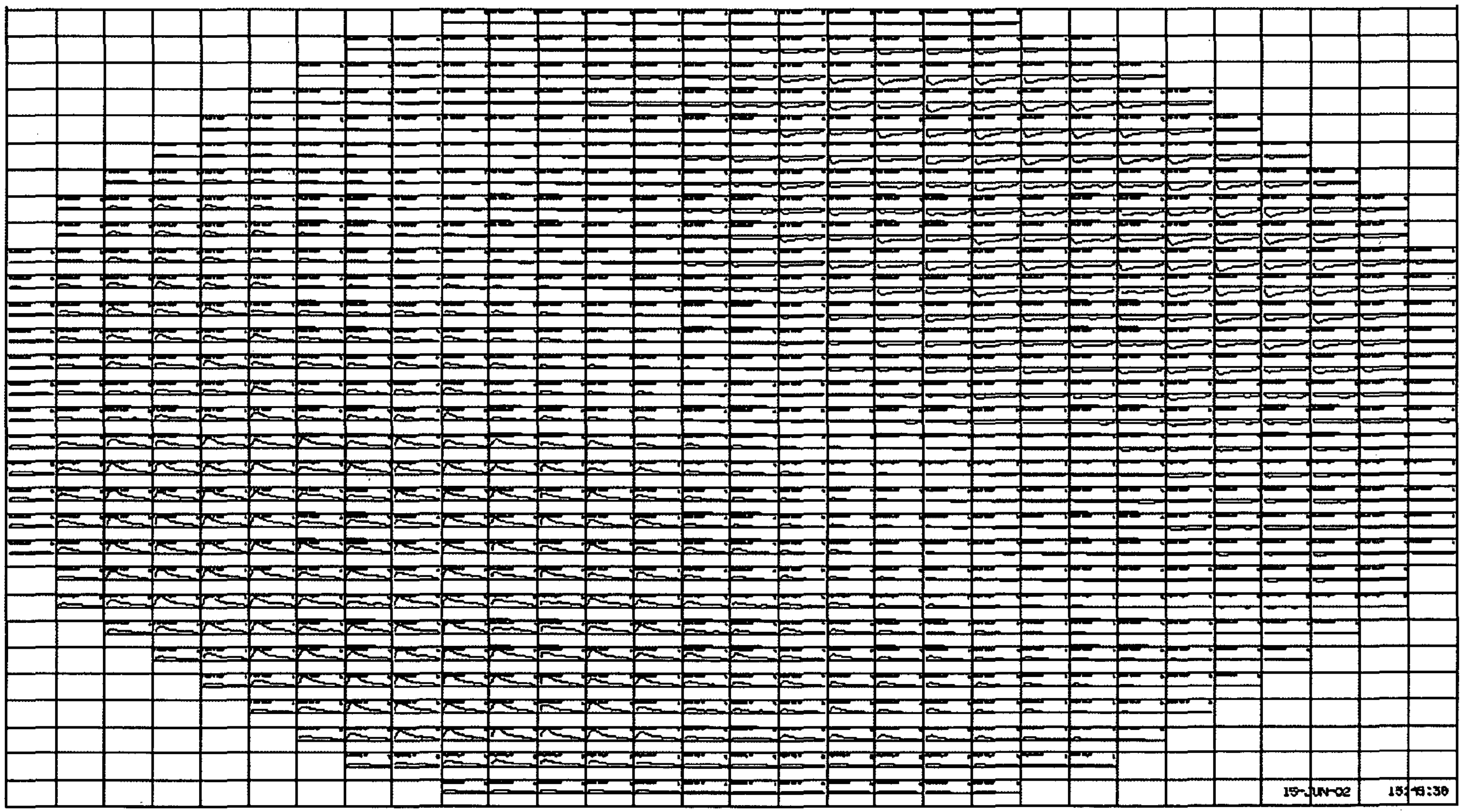


Figure 3-7 OPRM Channel Assignment Map for 444 Bundle Core

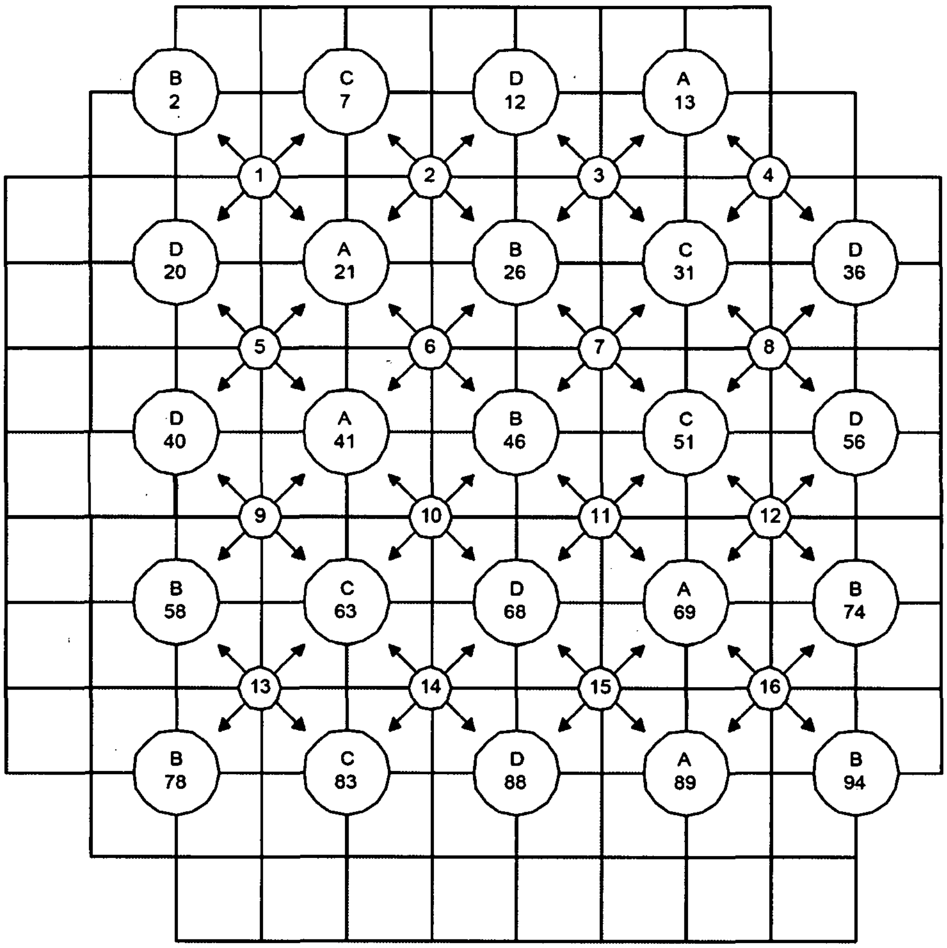


Figure 3-8 OPRM Channel Assignment Map for 624 Bundle Core

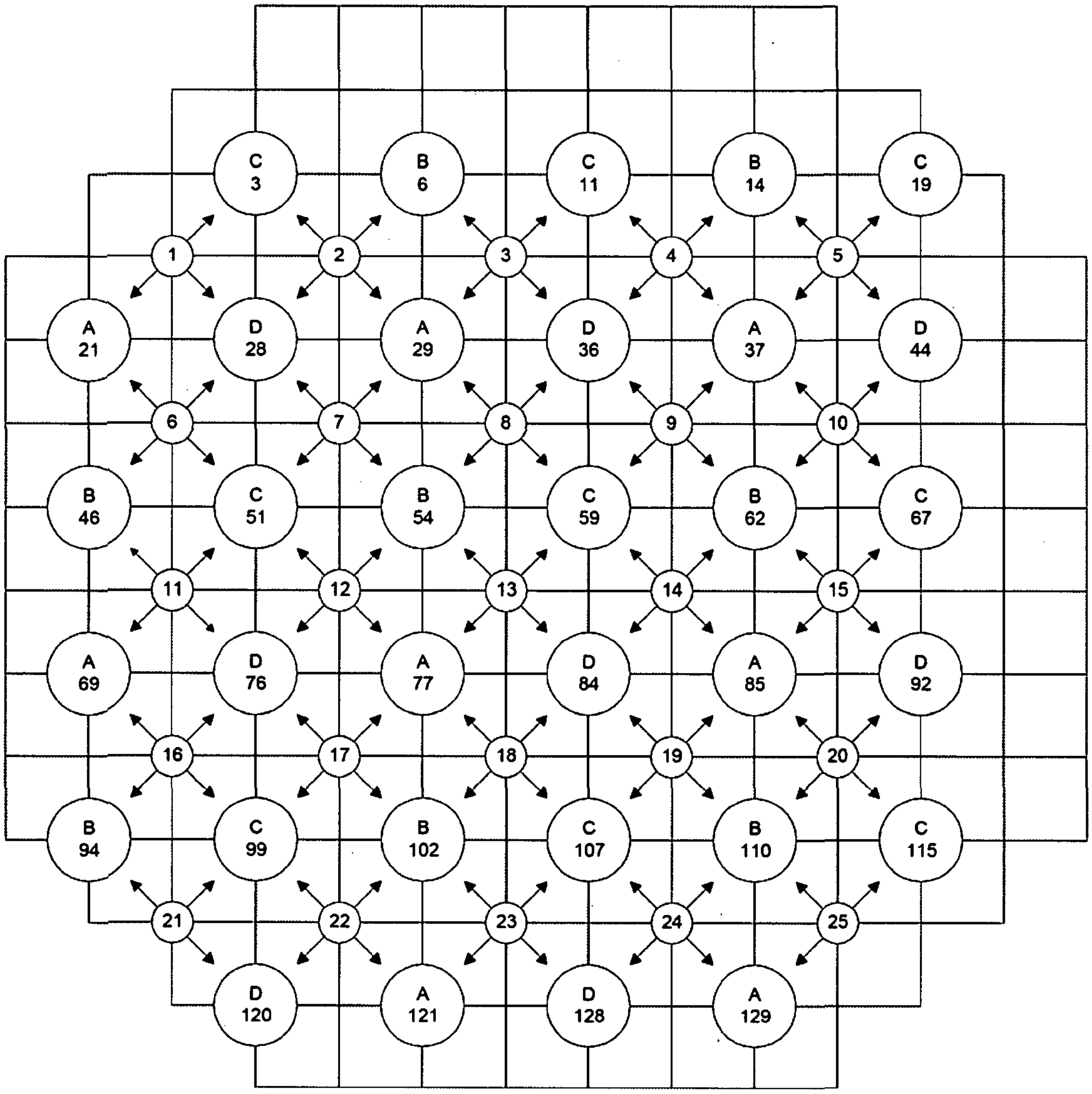
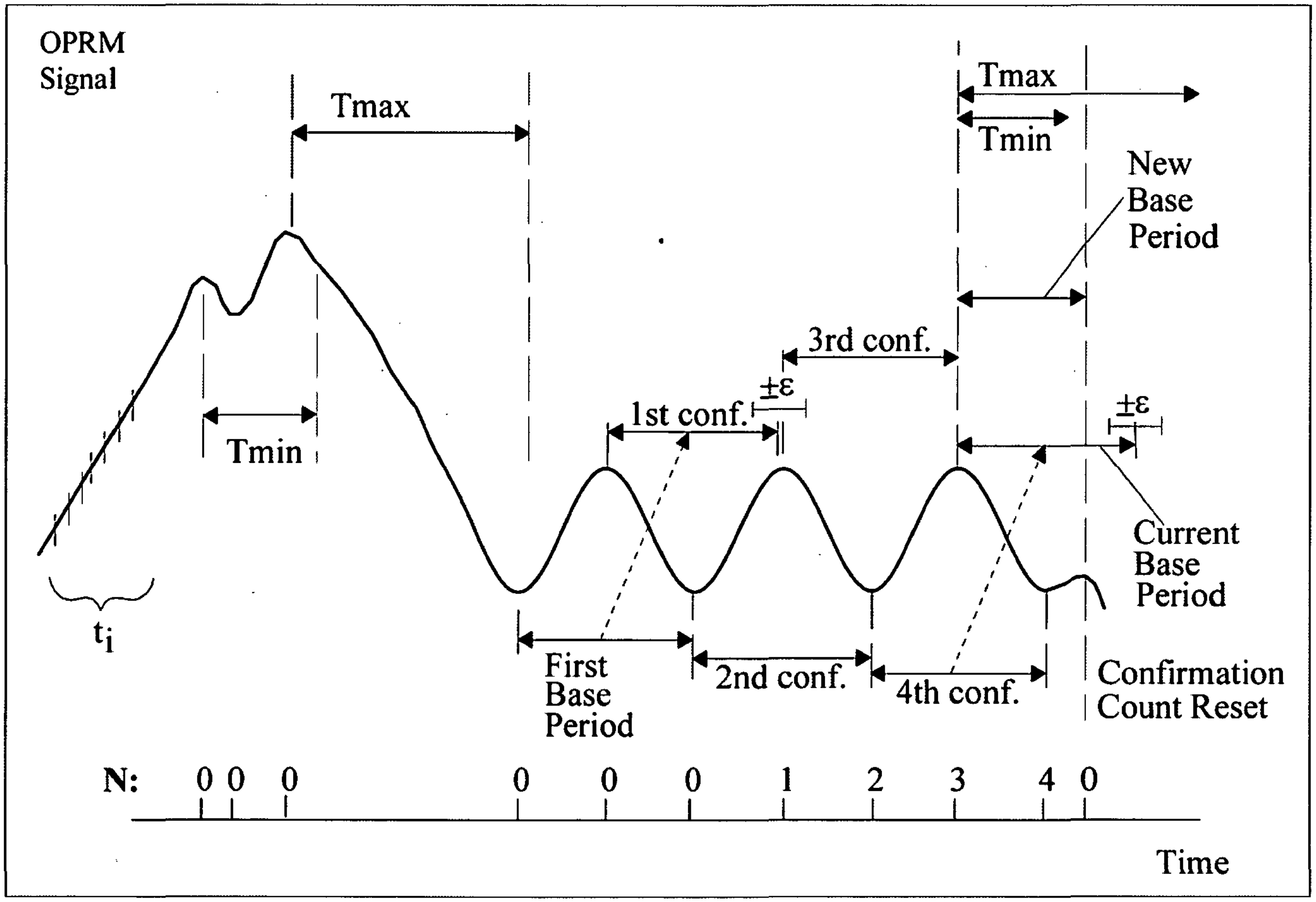


Figure 3-9 PBA Successive Period Confirmation Process



4.0 LICENSING BASIS

4.1 OVERVIEW

This section demonstrates on a generic basis that the DSS-CD system and its associated setpoints result in timely suppression of oscillations without violating the SLMCPR for anticipated instability events. A plant-specific confirmation assessment is performed whenever design changes beyond a specified generic applicability envelope are introduced that may affect stability performance and for each cycle to ensure that the generic DSS-CD basis remains valid for plant reload applications.

The presence of reactor instability can challenge the fuel SLMCPR. This occurs when fuel cladding heat flux and channel coolant flow rates deviate from steady state conditions during power oscillations significantly above the normal neutron noise level. To comply with GDC 12, protection of the SLMCPR can be accomplished by either detecting and suppressing instability induced power oscillations, or preventing them altogether.

The existing "detect and suppress" algorithms of LTS Option III (Reference 3) are based on a common approach. An OPRM cell signal oscillation, consistent with that characteristic of the reactor thermal-hydraulic oscillation frequencies, is identified. The presence of these characteristic power oscillations is then confirmed by various methods. The PBDA monitors successive oscillation periods and provides an oscillation amplitude trigger to generate a reactor trip signal. The GRA consists of an oscillation growth rate limit, which if exceeded, generates a reactor trip. Finally, the ABA consists of an oscillation amplitude limit, which if exceeded, generates a reactor trip

The Option III licensing basis (Reference 3) relies on the PBDA, with setpoints based on a combination of power oscillation period confirmation counts and oscillation amplitude. These setpoints are designed to ensure that the SLMCPR is not violated by the presence of growing power oscillations resulting from anticipated instability events. Option III methodology reliance on a fixed amplitude setpoint, which is associated with the SLMCPR, requires quantification of the MCPR performance as a function of power oscillation scenarios for the full spectrum of core designs and operating conditions.

The DSS-CD methodology is also based on identification and confirmation of power oscillation periods, characteristic of reactor instability. However, the confirmation process in this approach takes place at the threshold of reactor instability. By providing suppression at these conditions, the development of power oscillations that could challenge the SLMCPR is avoided. This early recognition function is performed by the Confirmation Density Algorithm (CDA), which identifies the unique features of instability threshold and generates a reactor trip before significant power oscillations and MCPR margin degradation develop.

4.2 APPROACH

The CDA and its associated setpoints are described in Section 3.3.1. The Confirmation Density (CD) and Amplitude Discriminator (AD) setpoints are used by the CDA to protect the SLMCPR from anticipated instability events. These anticipated events exhibit gradual reactor transition from a stable to an unstable configuration. The physical parameters in a reactor that are critical to the coupled thermal-hydraulic and neutronic stability characteristics require a finite time to realign following an anticipated transient that results in power oscillations.

At the instability threshold, although the decay ratio may constantly increase, the power oscillations do not experience a significant amplitude growth because the decay ratio is less than 1.0. Only when the decay ratio exceeds 1.0, following the instability inception, can the oscillation amplitude start to appreciably increase.

The CDA is designed to provide effective early protection of the fuel SLMCPR. No significant MCPR degradation is expected during the short duration between the initial oscillation recognition for the specified CD [[

]] As a result, power oscillations are not permitted to grow significantly above the background neutron noise level.

Significant margin to the SLMCPR is assured at the instability inception, which may be reached as a result of:

a. Normal operational maneuvers, which maintain significant MCPR margin at off-rated conditions,

b. Anticipated events from off-rated conditions, which are expected to be mild and retain substantial MCPR margin, or

c. Anticipated flow reduction events from rated conditions, which are expected to result in a MCPR margin increase from the required margin at the initial rated conditions (i.e., Operating Limit Minimum Critical Power Ratio (OLMCPR)).

As stated above, the transition to fully developed instability is gradual. Therefore, the CDA protection precludes any significant MCPR margin degradation as a result of anticipated instability events. The SLMCPR is protected by generating a reactor scram before the core thermal-hydraulic conditions deviate significantly from steady state conditions. Based on BWR operational experience, the anticipated increase in background neutron noise level at the instability inception is no more than approximately a factor of 3 prior to reactor trip, and therefore has an insignificant effect on MCPR margin.

To confirm the MCPR performance of anticipated instability events, reasonably limiting, best-estimate event simulations are performed using the GE TRACG code for a specified range of operating conditions, selected GE BWR product lines, and anticipated oscillation modes. It must be emphasized that these TRACG event simulations are not used to determine the CDA setpoints, nor are they used to establish the SLMCPR. Their sole purpose is to confirm the inherent MCPR margin afforded by the CDA design. Method qualifications and uncertainty treatment are addressed in Section 5.0.

4.3 GENERIC APPLICABILITY ENVELOPE

The confirmation process of MCPR performance afforded by the DSS-CD for anticipated instability events is established on a generic basis. To this end, a set of key parameters is identified and a range established to define a generic applicability envelope. Future plant-specific designs, which are bounded by the generic applicability envelope, are confirmed based on the generic basis documented in this report. If any of the key parameters is outside of the generic applicability envelope for plant-specific application, additional justification may be required, as described in Section 6.0. This section addresses TLO considerations. SLO is addressed in Section 4.4.2.

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The specified range established for each of these parameters is summarized in Table 4-1. The plant specific review process, confirming the continued applicability of the DSS-CD generic applicability envelope, is documented in Section 6.0. The analyses documented in this report, demonstrating the MCPR performance on a generic basis for anticipated core wide and regional mode oscillations, address the specified range of the generic applicability envelope key parameters.

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4.4 SLMCPR PROTECTION CONFIRMATION

The SLMCPR protection confirmation is based on anticipated instability events, which are defined to include core wide and regional modes oscillations with full core participation at reasonably limiting conditions and core designs. These events are initiated as a result of anticipated transients or normal operational maneuvers. All other instability events are considered unanticipated events. They do not require SLMCPR protection and are addressed by the defense-in-depth solution features of DSS-CD. Consistent with the DSS-CD generic confirmation envelope, reasonably limiting events are selected and simulated by TRACG to quantify their effect on the margin to SLMCPR. A generic DSS-CD procedure specifying bounding CPR uncertainty is established and used to confirm that the margin to the SLMCPR for the reasonably limiting best-estimate events is adequate. Section 4.4.1 addresses TLO considerations and Section 4.4.2 addresses SLO.

The purpose of the confirmation analysis event matrix is to evaluate the licensing basis generic applicability envelope (Table 4-1) and any future changes outside this envelope. The events to be considered are identified in the matrices associated with TLO (Table 4-2) and SLO (Table 4-7).

4.4.1 Two Loop Operation

The TLO limiting events, selected to confirm that the SLMCPR is protected by the DSS-CD design, are established based on a review of all potential anticipated instability event initiators. Anticipated instability events may be initiated as a result of:

a. Normal operational maneuvers,

b. Anticipated events from off-rated operating conditions, or

c. Anticipated flow reduction events from rated conditions.

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4.4.1.1 Event Simulation

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The simulation results in the following section are used to assess the MCPR response and margin to the SLMCPR. The transient responses of key simulation parameters, including core power and flow, core inlet subcooling, hot channel power, hot channel flow, leading OPRM cell normalized signal and CPR, are presented in [[

]] The event suppression occurs prior to any significant amplitude growth and CPR degradation, as discussed in the next section.

4.4.1.2 MCPR Performance

The margin to the SLMCPR for each of the TRACG simulated events is calculated by applying the DSS-CD evaluation methodology to the event MCPR results. The evaluation methodology and the event specific MCPR margin results are discussed in the following subsections.

Evaluation Methodology

The DSS-CD evaluation methodology establishes the time sequence from the oscillation detection through suppression, and determines the SLMCPR margin from the TRACG generated MCPR results. The TRACG simulations represent best-estimate calculations for reasonably limiting instability scenarios. A CSAU assessment is provided in Section 5.0.

The DSS-CD evaluation methodology represents a significant simplification from the Option III licensing methodology. [[

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The elimination of these elements is possible because of the:

a. Early detection and suppression of oscillations afforded by the CDA,

b. Elimination of determining the amplitude setpoint directly based on SLMCPR protection (i.e., the final MCPR is equal or just above the SLMCPR) in the licensing basis detection algorithm, and

c. Use of TRACG to simulate the full instability scenario, from the steady state initial condition to the instability suppression.

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Best Estimate MCPR Margin

The DSS-CD evaluation methodology has been applied to the cases specified in the confirmation analysis event matrix (Table 4-2). Table 4-4 summarizes the nominal MCPR performance and margins to the SLMCPR for these cases. [[

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For all cases in Table 4-4, adequate margin to the SLMCPR is maintained. [[

]] and therefore confirms on a generic basis the CDA early detection capability and the CDA setpoints selection.

MCPR Uncertainty Assessment

The Code Scaling Applicability and Uncertainty (CSAU) bounding approach described in Section 5.2 was applied to the [[

]] the CSAU bounding approach resulted, as expected, in a significant decrease in CPR margin.

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]] For each of these cases the final MCPR, including the DSS-CD procedure component uncertainties, and the resulting SLMCPR margin are summarized in Table 4-5. For all cases, adequate margin exists, confirming the DSS-CD protection approach and setpoint selection. [[

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4.4.2 Single Loop Operation

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]] The event suppression occurs prior to any significant amplitude growth and CPR degradation.

The margin to the SLMCPR for the TRACG SLO simulated event is calculated by applying the DSS-CD evaluation methodology to the event MCPR results similar to the TLO process. [[

]] and therefore confirms on a generic basis the CDA early detection capability and the CDA setpoints selection for SLO.

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]] The final MCPR, including the DSS-CD procedure component uncertainties, and the resulting SLMCPR margin are summarized in Table 4-10, demonstrating adequate margin and confirming the DSS-CD protection approach and setpoint selection for SLO.

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4.5 Solution Armed Region

The DSS-CD solution is designed to reliably and readily detect and suppress both core wide and regional mode oscillations prior to violating the SLMCPR for anticipated oscillations. The ability to trip the reactor and generate system alarm is automatically enabled at power and flow conditions potentially susceptible to power oscillation. The trip-enabled region is termed the Armed Region. For DSS-CD, the Armed Region boundaries are specified on a generic basis to envelop power and flow conditions potentially susceptible to power oscillation.

The trip and alarm functions are automatically enabled below a specified flow level and above a specified core power level. The DSS-CD Armed Region is illustrated in Figure 4-46. The specified flow level is designed to disarm the trip and alarm functions during rated power operations. Because power oscillations are not expected at rated power operations and the reactor is operated at these conditions most of the time, disarming the trip and alarm functions reduces the probability of unnecessary spurious scrams. In addition, the specified flow level is designed to arm the trip and alarm functions at a flow level that bounds the core conditions potentially susceptible to power oscillation.

To accomplish these goals, the flow level is set just below the minimum flow associated with rated power operation. The flow boundary of the Armed Region is generically specified as 75% of rated recirculation drive flow for plants licensed for MELLLA+ operations and 70% of rated recirculation drive flow for plants not licensed for MELLLA+ operations. The flow signal used to implement the Armed Region is the relative recirculation drive flow. The relative recirculation drive flow at the 100% core power and 100% core flow statepoint is defined as the rated recirculation drive flow. Because the relationship between the core flow and recirculation drive flow has a weak dependence on core power, small variation in the Armed Region flow boundary in terms of core flow may be observed during operation as a function of the core power level (or load line). However, this is acceptable because the resulting effect of slight variation in the Armed Region boundary in terms of core flow has a negligible effect on stability margin based on the low decay ratios around the Armed Region boundary as demonstrated in Table 4-12.

The specified power level is designed to arm the trip and alarm functions at a power level that bounds the core conditions potentially susceptible to anticipated power oscillations. This power level is selected generically at the MCPR monitoring threshold of 25% Original Licensed Thermal Power (OLTP). For a power-uprated plant, the MCPR monitoring threshold may have been scaled to a lower percent value. This scaled value defines the Armed Region boundary in this situation. Instabilities are not expected to occur below 30% OLTP. In the unlikely event of significant stability margin degradation at this power level, the loss of margin is gradual, allowing for early detection by the system. In addition, below the MCPR monitoring threshold, an instability event would not be expected to grow large enough to threaten the SLMCPR. This expectation is due, in part, to the large MCPR margin that exists at low power operation.

To demonstrate that the generic Armed Region boundaries are associated with stable core conditions, ODYSY (Reference 6) calculations were performed for reasonably limiting conditions on the boundaries of example BWR/4 and BWR/6 plants for both MELLLA+ and pre-MELLLA+ operating domains. Table 4-12 summarizes the state point conditions and calculated decay ratio results. [[

]] As expected, both channel and core decay ratios are low, indicating weak susceptibility to both core wide and regional oscillations at or near the Armed Region boundaries.

4.6 APPLICATION TO NON-GE FUEL DESIGN

The fuel design range of applicability of this report is specified in Tables 4-1 and 4-6. Fuel designs not covered in this report, including non-GE fuel, are addressed as outlined in Section 6.0. This report methodology, or equivalent NRC approved methodology, will be used to confirm adequate MCPR performance of the new fuel design. Application of this report MCPR confirmation methodology to existing non-GE fuel design is expected to result in confirmation of adequate MCPR margins because of the fuel design thermal-hydraulic compatibility and the robustness of the DSS-CD solution.

Table 4-1 TLO DSS-CD Licensing Basis Generic Applicability Envelope

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Table 4-2 TLO TRACG Confirmation Analysis Event Matrix

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Table 4-3 TLO DSS-CD Evaluation Methodology Summary

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Table 4-4 TLO Nominal TRACG Confirmation Analysis MCPR Performance

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Table 4-5 TLO DSS-CD Bounding TRACG MCPR Margin

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Table 4-6 SLO DSS-CD Licensing Basis Generic Applicability Envelope

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Table 4-7 SLO TRACG Confirmation Analysis Event Matrix

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Table 4-8 SLO DSS-CD Evaluation Methodology Summary

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Table 4-9 SLO Nominal TRACG Confirmation Analysis MCPR Performance

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Table 4-10 SLO DSS-CD Bounding TRACG MCPR Margin

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Table 4-11 Trip Times for TRACG Confirmation Analysis

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Table 4-12 ODYSY Confirmation of the Armed Region Boundaries

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Figure 4-1 [[

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Figure 4-2 [[

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Figure 4-3 [[

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Figure 4-4 [[

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Figure 4-5 [[

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Figure 4-45 [[

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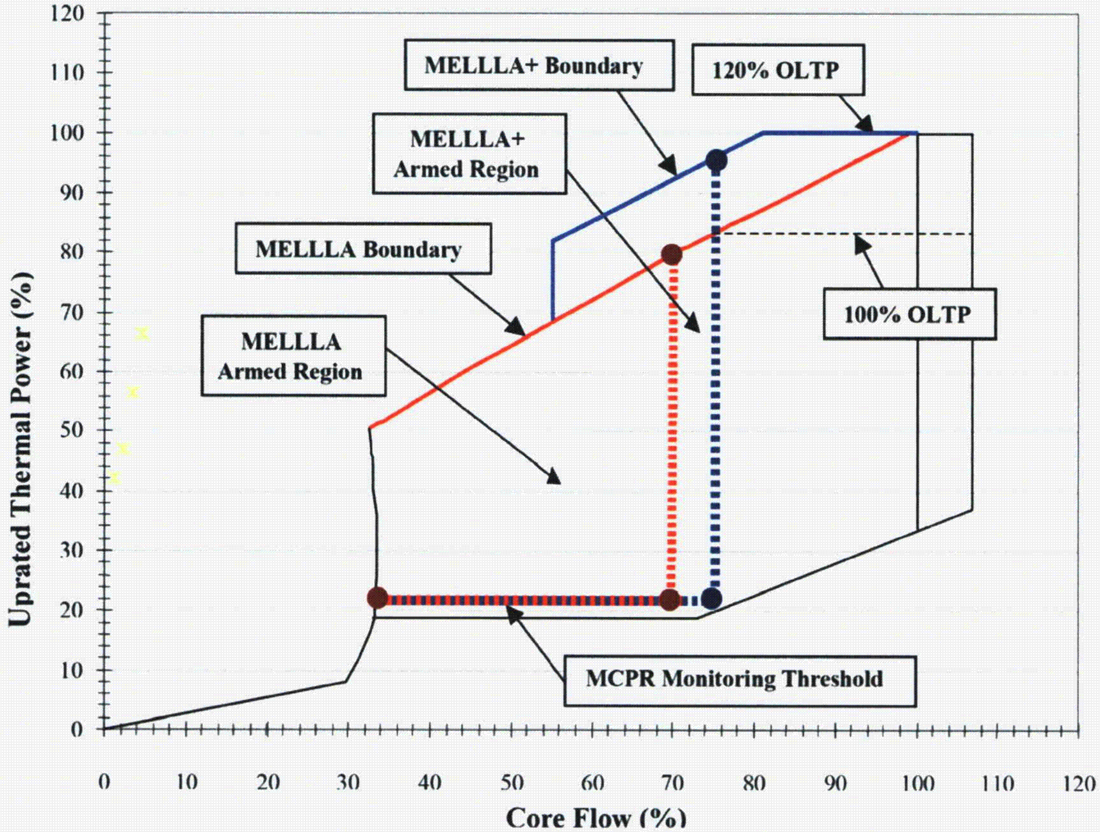
Figure 4-46 DSS-CD Armed Region Illustration

(100% EPU = 120% OLTP)



Note: The Armed Region flow boundary is defined and implemented by the recirculation drive flow and is shown as an approximate vertical line as a function of core flow for illustration purposes only.

5.0 SOLUTION QUALIFICATIONS AND UNCERTAINTIES

5.1 TRACG APPLICATION

The TRACG code is used to simulate [[ ]] events to confirm the DSS-CD solution early oscillation detection and suppression capability. The TRACG event simulations are not used to establish the DSS-CD CDA design or setpoints. The purpose of the TRACG qualification review is to provide background for the code limited use in support of the DSS-CD application.

5.1.1 TRACG Qualifications

TRACG is a GE proprietary version of the Transient Reactor Analysis Code (TRAC). TRACG uses advanced best-estimate one-dimensional and three-dimensional methods to model the phenomena that are important in evaluating the operation of BWRs. Best-estimate analyses performed with TRACG have been approved by the NRC to support licensing applications in different areas, including specific thermal-hydraulic instability performance and Anticipated Operational Occurrence (AOO) transients.

TRAC was originally developed for pressurized water reactor (PWR) analysis by Los Alamos National Laboratory, the first PWR version of TRAC being TRAC-P1A. The development of the BWR version of TRAC started in 1979 in close cooperation between GE and Idaho National Engineering Laboratory. The objective of this cooperation was the development of a version of TRAC capable of simulating BWR LOCAs. The main tasks consisted of improving the basic models in TRAC for BWR applications and in developing models for specific BWR phenomena and components.

GE continued to develop TRACG to upgrade the capabilities of the code to include stability, transient, and anticipated transients without scram (ATWS) applications. During this phase, major developments included the implementation of the three-dimensional kinetics model and an implicit integration scheme. Modeling of the BWR fuel bundle was also improved.

TRACG includes a multi-dimensional, two-fluid model for the reactor thermal-hydraulics and a three-dimensional reactor kinetics model. The models can be used to simulate a large variety of test and reactor configurations. These features allow for detailed, best-estimate simulation of a wide range of BWR phenomena, and are described in detail in the TRACG Model Description Licensing Topical Report (Reference 8).

TRACG has been extensively qualified against separate effects tests, component performance data, integral system effects tests and full-scale BWR plant data. The details are presented in the TRACG Qualification Licensing Topical Report (Reference 9).

5.1.2 Application Approach

This section demonstrates the acceptable use of TRACG analysis results for licensing BWR/3-6 power plants to support the DSS-CD licensing basis. GE has provided information to support the use of TRACG as an extension to the previously approved method of analyzing BWR stability and demonstrating compliance with licensing limits (References 1 and 2). Stability events are analyzed to establish the reactor system response, including the calculation of the CPR. This report addresses TRACG capabilities to confirm that acceptable fuel design limits are not exceeded during specified stability event.

The originally approved TRACG stability application for Option III (Reference 3) evaluated the CPR response versus the hot channel oscillation magnitude based on conservative pre-oscillation initial conditions. The event was assumed to initiate at off-rated equilibrium feedwater temperature, resulting in a fast oscillatory growth. The TRACG application for DSS-CD [[

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This section describes the quantification of key parameter uncertainties, as applied to the TRACG instability event simulations. The analysis of these instability events accounts for the uncertainties and biases in the models and plant parameters, using a bounding approach. The uncertainties and biases considered include:

- Model uncertainties,
- Experimental uncertainties and uncertainties related to test scaleup, and
- Plant parameter uncertainties.

The overall analysis approach is consistent with the Code Scaling, Applicability and Uncertainty (CSAU) analysis methodology (Reference 10) and Regulatory Guide 1.157 (Reference 11), and addresses all the elements of the NRC-developed CSAU evaluation methodology. In the CSAU process, the model uncertainty is derived from the propagation of individual model uncertainties through code calculations, and experimental comparisons are used as a check on the derived uncertainty. The detailed demonstration of the CSAU analysis methodology for DSS-CD is addressed in Section 5.2.

5.1.3 Advantages of TRACG Use for Stability Evaluations

TRACG use for stability analyses includes the following advantages:

- [[ ]] TRACG is not only capable of simulating core response, but also determining the response of individual (including limiting) channels, including transient critical power response.
- With its 3-D kinetics model, TRACG is capable of simulating the complex thermal-hydraulic and neutronic interactions of the core. The nuclear model is consistent with the PANACEA 3-D steady-state simulator (Reference 12), which is constantly being benchmarked against steady-state nuclear data.
- TRACG calculates the CPR directly.

5.1.4 Conformance with CSAU Methodology

The CSAU demonstration application to TRACG BWR stability analysis addresses all the elements of the NRC-developed CSAU evaluation methodology. The CSAU approach is a rigorous process for evaluating the total model and plant parameter uncertainty for nuclear power plant calculations. The process for applying best-estimate codes and quantifying the overall model and plant parameter uncertainties represents the best available practice. While the CSAU methodology was developed for application to LOCA scenarios, there are no technical reasons that prevent CSAU methodology from being applied to other event scenarios, such as stability.

The CSAU methodology consists of 14 steps, as outlined in Table 5-1, which summarizes how these steps are addressed for the DSS-CD demonstration.

5.2 CSAU METHODOLOGY APPLICATION

This section presents the CSAU methodology demonstration for DSS-CD. [[

]] and documented in Section 4.4.3. The demonstration of the CSAU methodology documented in this section is limited to the DSS-CD solution.

Each of the 14 steps of the CSAU methodology application to the DSS-CD demonstration is discussed below.

1. Stability Scenario Specification

The stability scenarios are those associated with anticipated stability events in BWR/3-6 type plants. [[

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2. Nuclear Power Plant Selection

The DSS-CD is applicable to BWR/3-6 plant product lines.

3. Phenomena Identification and Ranking

The critical safety parameter for stability events is the MCPR. The MCPR value is determined by the governing physical phenomena. The phenomena identification and ranking table (PIRT) is used to delineate the important physical phenomena. PIRTs are ranked with respect to their impact on the critical safety parameters. For example, the MCPR is determined by the reactor short-term response to stability events. The coupled core neutronic and thermal-hydraulic characteristics govern the neutron flux, reactor pressure, and core flow in a stability transient.

All processes and phenomena that occur during a transient do not equally influence plant behavior. Disposition analysis is used to reduce all candidate phenomena to a manageable set by identifying and ranking the phenomena with respect to their influence on the critical safety parameters. The phases of the events and the important components are investigated. The processes and phenomena associated with each component are examined. Cause and effect are differentiated. After the processes and phenomena have been identified, they are ranked with respect to their effect on the critical safety parameters for the event.

PIRTs are developed with only the importance of the phenomena in mind and are independent of whether or not the model is capable of handling the phenomena and whether or not the model shows a strong sensitivity to the phenomena. For example, two phenomena may be of high importance yet may tend to cancel each other so that there is little sensitivity to either phenomenon. Both phenomena are of high importance because the balance between these competing phenomena is important.

Table 5-2 was developed to identify the phenomena that govern BWR/3-6 stability responses, and represents a consensus of GE expert opinions. The stability transient events have been categorized into three distinct groups:

- Channel thermal-hydraulic instability,
- Core-wide instability, and
- Regional instability.

For each event type, the phenomena are listed and ranked for each major component in the reactor system. The ranking of the phenomena is done on a scale of high importance to low importance or not applicable, as defined by the following categories:

- **High importance (H):** These phenomena have a significant impact on the primary safety parameters and should be included in the overall uncertainty evaluation.
- **Medium importance (M):** These phenomena have insignificant impact on the primary safety parameters and may be excluded in the overall uncertainty evaluation.
- **Low importance (L) or not applicable (NA):** These phenomena have no impact on the primary safety parameters and need not be considered in the overall uncertainty evaluation.

The PIRT serves a number of purposes. First, the phenomena are identified and compared to the modeling capability of the code to assess whether the code has the necessary models to simulate the phenomena. Second, the identified phenomena are cross-referenced to the qualification basis to determine what qualification data are available to assess and qualify the code models and to determine whether additional qualification is needed. As part of this assessment, the range of the PIRT phenomena covered in the tests is compared with the corresponding range for the intended application to establish that the code has been qualified for the highly ranked phenomena over the appropriate range.

Table 5-2 also tabulates a number of derived parameters (e.g. ratio of core power to core flow) important to reactor instability.

Using the PIRT table ranking results, the uncertainties for the highly ranked PIRT phenomena are established and evaluated based on a bounding analysis to arrive at the total model uncertainty.

4. Frozen Code Version Selection

A frozen code version (TRACG02A) has been used in this evaluation.

5. Code Documentation

The TRACG program is a controlled Engineering Computer Program (ECP), and therefore, the documentation provided to the users is also maintained in a controlled manner. References 7 and 8 document both the TRACG licensing basis and application methodology.

6. Determination of Code Applicability

This section demonstrates the applicability of TRACG for the analysis of anticipated instability events in BWRs. The capability of the TRACG models to treat the highly ranked phenomena and the qualification assessment of the TRACG code for stability applications is examined.

The capability to simulate an event for a nuclear power plant depends on four elements:

- Conservation equations, which provide the code capability to address global processes,
- Correlations and models, which provide the code capability to model and scale particular processes,
- Numerics, which provide the code capability to perform efficient and reliable calculations, and
- Structure and nodalization, which address the code capability to model plant geometry and perform efficient and accurate calculations.

Consequently, these four elements must be considered when evaluating the applicability of the code to the event of interest for the nuclear power plant calculation. The key phenomena for each event are identified in generating the PIRTs for the intended application. The capability of the code to simulate the key phenomena for stability applications is addressed, documented, and supported by the code qualification in Reference 7. The difference between the (H) ranked PIRTs of Table 5-2 and those of Reference 7 are the inclusion of:

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[[

]] The derived core stability parameters are combinations of parameters considered elsewhere in the bounding treatment. Therefore the difference between the PIRT ranking of Reference 7 and Table 5-2 is not significant and the assessment and qualification matrices of Reference 7 are applicable for this CSAU evaluation.

7. Establishment of Assessment Matrix

The qualification assessment of the TRACG models is summarized in Reference 7. The models have been identified so that they may be easily correlated to the model description and qualification reports. For each model, the relevant elements from the Model Description LTR (Reference 8) and the Qualification LTR (Reference 9) are identified.

For the governing BWR phenomena, TRACG qualifications have been performed against a wide range of data, including instability data. The list of phenomena is cross-referenced to the model capabilities in Table 4-1 of Reference 7. Similarly, as shown in Table 4-2 of Reference 7, the complete list of phenomena is cross-referenced to the qualification assessment basis. Data from separate effects tests, component tests, integral system tests and plant tests, as well as plant data have been used to qualify the capability of TRACG to model the phenomena.

8. Nuclear Power Plant Nodalization Definition

The nodalization strategy for the various reactor components was developed from the qualification of TRACG against test data for these components. The same consistent nodalization strategy was then applied for full-scale plant calculations. The adequacy of the nodalization has been demonstrated and supported by sensitivity studies. Standard nodalization for modeling of BWR reactor vessels and other components have been presented in the TRACG Qualification LTR (Reference 9).

Specific nodalization and additional details for the nodalization for some components may be critical for specific applications. [[

]] This is based on a nodalization study that examines the minimum number of fuel channels required to adequately model the CPR response for a regional mode oscillation.

9. Definition of Code and Experimental Accuracy

The code definition and experimental accuracy has been addressed in Reference 9. The TRACG code has been qualified against the LaSalle-2 instability event (March 1988), the Leibstadt Cycle 1 regional instability tests, the Forsmark-1 stability tests (January 1989), and the Cofrentes Cycle 6 instability event (January 1991). The overall TRACG prediction agrees well with the experimental data.

10. Determination of Effect of Scale

Effects of scale have been addressed as part of the model development as well as the qualification. In the TRACG model description report (Reference 8), the applicability of the basic models and correlations are stated and shown to cover the scale and operating range of BWRs. The qualification of TRACG (Reference 9) covers separate effects tests, scaled as well as full-scale component performance tests, scaled integral system effects tests, and full-scale BWR plant tests. The qualification shows that data from scaled test facilities and full-scale plants are both well predicted. There is no apparent effect of scale in TRACG. In addition, demonstrations of the application methodology for TRACG have shown that full-scale plant data are bounded, when the effect of the model uncertainties are accounted for. Because these model uncertainties have primarily been determined from scaled experiments, this again demonstrates that there is no significant impact of scale on TRACG.

11. Determination of the Effect of Reactor Input Parameters and State

Overall model biases and uncertainties for the stability application are assessed for each high ranked phenomena by using a combination of comparisons of calculated results to: (1) separate effects test facility data, (2) integral test facility test data, (3) component qualification test data and (4) BWR plant data. Where data is not available, cross-code comparisons or engineering judgment are used to obtain approximations for the biases and uncertainties. For some phenomena that have little impact on the calculated results, it is appropriate to simply use a nominal value or to conservatively estimate the bias and uncertainty.

The phenomena for BWR stability have already been identified and ranked, as indicated in Step 3 above.

Code inputs can be divided into four broad categories: (1) geometry inputs, (2) model selection inputs, (3) initial condition inputs, and (4) plant parameters. For each type of input, it is necessary to specify the value for the input. If the calculated result is sensitive to the input value, then it is also necessary to quantify the uncertainty in the input.

The geometry inputs specify lengths, areas and volumes. Uncertainties in these quantities are due to measurement uncertainties and manufacturing tolerances. These uncertainties usually have a much smaller impact on the results than do uncertainties associated with the modeling simplifications.

Individual geometric inputs are the building blocks for the spatial nodalization. The spatial nodalization includes modeling simplifications such as the lumping together of individual elements into a single model component. For example, several similar fuel channels may be lumped together and simulated as one fuel channel group. An assessment of these kinds of simplifications, along with the sensitivities to spatial nodalization, is included in the TRACG Qualification LTR (Reference 9).

Inputs are used to select the features of the model that apply for the intended application. Once established, these inputs are fully specified in the procedure for the application and do not change.

A plant parameter is defined as a plant-specific quantity such as a protection system scram characteristic, etc. Plant parameters influence the characteristics of the transient response and have essentially no impact on steady-state operation.

Initial conditions are those conditions that define a steady-state operating condition. Initial conditions may vary due to the allowable operating range or due to uncertainty in the measurement at a give operating condition. The plant Technical Specifications and Operating Procedures provide the means by which controls are instituted and the allowable initial conditions are defined. At a given operating condition, the plant's measurement system has inaccuracies that also must be accounted for as an uncertainty.

Table 5-3 identifies items that have been recognized as having an impact on the critical safety parameter for stability application. These items are represented in the table by ID, description, ranking (H for High), and bias and deviation information. Table 5-4 lists the key plant initial conditions/parameters that are high ranked for the stability application. For the high ranked phenomena, the bases used to establish the nominal value, bias and uncertainty for that parameter are documented.

12. Performance of Nuclear Power Plant Sensitivity Calculations

Two plant types (BWR/3-5 and BWR/6) with different limiting operating conditions are evaluated for the stability application. [[

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13. Determination of Combined Bias and Uncertainty

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14. Determination of Total Uncertainty

A commonly used approach in traditional conservative analyses is combining the uncertainties linearly, by applying bounding models for the phenomena and by setting plant parameters to values expected to produce the most limiting plant response. [[

]] Separate calculations were performed to characterize the effect of each response parameter important for stability in order to define the appropriate uncertainty range. The total uncertainty treatment is based on reasonably limiting initial conditions and model uncertainties identified in the previous CSAU steps.

The advantage of this approach is that it requires no more than one computer run for each output parameter of interest. The most significant disadvantage of this method is that it is very conservative. In extreme cases, it can give unrealistic results, and no statistical quantification of the margins to design limits is possible.

As discussed earlier in this section, the CSAU [[

]] is documented in Section 4.4.3.

5.3 DETECTION ALGORITHM TESTING

The DSS-CD licensing basis detection algorithm, the CDA, relies on the recognition of successive periods in OPRM cells signals that consists of two related pattern recognition elements:

a. Successive period detection, and

b. Confirmation density recognition.

Actual plant data and TRACG event simulations that are used to test these CDA elements are documented in this section.

5.3.1 Successive Period Detection

The PBA application in DSS-CD for the purpose of recognizing successive oscillation periods is similar to Option III. The key PBA testing from References 1 and 2 is summarized in Table 5-5. Testing of the PBA application to OPRM cells was performed in support of Option III algorithm qualifications and is also summarized in Table 5-5.

Because certain changes are introduced to the PBA for application to the CDA, selected retesting is appropriate. The PBA modifications and restrictions specified in Section 3.4.1.1 are expected to have insignificant effect on the testing and qualifications documented in References 1 and 2. [[

]] Table 5-5 lists the retested plant data, which includes Pilgrim stable startup data and KKL instability event data. These retests have demonstrated that the PBA changes have insignificant effect on the detection results, as expected.

The PBA was applied to selected TRACG power traces to test the algorithm capability to recognize the inception of instability [[ ]]. The PBA, consistent with the modifications and restrictions specified in Section 3.4.1.1, provided timely identification of the inception of instability oscillations and continuous recognition of successive period counts. [[

]]

5.3.2 Confirmation Density Recognition

The CDA requires simultaneous successive counts of multiple OPRM cells for generating an OPRM channel trip signal. The testing of the instability events listed in Table 5-5 were previously performed for multiple LPRMs. However, the relative timing of the successive period counts is not included in Reference 2. To demonstrate the CD approach and effectiveness, multiple LPRM signals from the KKL Cycle 7 regional instability test event and Columbia Cycle 8 core wide instability event were examined by the PBA, integrated to calculate the CD as function of time, and compared to the algorithm CD setpoint.

A segment of the KKL Cycle 7 regional instability test, STAB5, was selected to demonstrate the CDA performance. This test segment is at the instability threshold and exhibits very gradual loss of stability margin. The PBA was applied to the available 25 LPRM signals that were recorded during the test. Figure 5-1 illustrates the stability performance of two LPRMs, including signal amplitude and PBA successive confirmation count. The LPRMs were selected to represent examples of responsive and unresponsive signals. Figure 5-2 depicts the CD based on the single LPRM PBA confirmation results. The figure illustrates the CDA responsiveness and ability to identify the instability inception and generate a trip signal when the CD setpoint [[ ]] is reached. The number and distribution of the LPRMs was not conducive for OPRM cell demonstration. OPRM cell demonstration is performed for the Columbia instability event below.

The KKL Cycle 7 regional instability test represents a significant challenge for the CDA demonstration. The oscillations were established under controlled test conditions and resulted in a very gradual instability inception. The test was also occasionally interrupted by manual operator actions (e.g., control rod movements). In addition, the test appears to exhibit precession characteristics during its instability inception. For instabilities resulting from anticipated events [[ ]] with no manual operator manipulations, full core coupling and distinct characteristic oscillatory behavior is expected to form early in the event.

The second CDA demonstration example consists of the Columbia Cycle 8 unplanned instability event. The PBA was applied to the available 80 LPRM signals that were recorded during the event. These LPRMs consist of LPRM levels A and C (i.e., bottom and third from bottom axial positions). They were divided into 2 representative RPS channels of 39 LPRMs (Channel 1) and 41 LPRMs (Channel 2), as illustrated in Figure 5-3. The figure also illustrates an OPRM cell assignment, which simulates 2 OPRM channels of 35 OPRM cells each. This OPRM cell assignment is similar to the Columbia's assignment, including adjustments to accommodate the available recorded LPRM signals. Most of the OPRM cells consist of 4 LPRMs and only a few with a lesser count.

Figure 5-4 illustrates the stability performance of a typical LPRM signal, including signal amplitude and PBA successive confirmation count. [[

]] which is initiated prior to any significant signal amplitude growth. The figure also includes a simulated OPRM cell signal, associated with the selected LPRM. It compares the performance of a 4-LPRM OPRM cell to one of its LPRM signals. [[

]]

Figure 5-5 depicts the CD based on a single LPRM per OPRM cell PBA confirmation results. The figure illustrates the CDA ability to identify the instability inception and generate an early trip signal when the CD setpoint [[ ]] is reached. Even though the event is developing slowly with a low growth rate, the increase in the number of confirming LPRMs is apparent. The figure demonstrates that the CD is not increasing prior to the development of oscillatory behavior, is associated with the instability threshold, and is rapidly increasing as the instability event develops.

The Columbia Cycle 8 instability event was also used to test the CDA detection capability with OPRM cells consisting of multiple LPRMs, as illustrated in Figure 5-3. Figure 5-6 depicts the OPRM CD performance, including the LPRM based CD for comparison. [[

]] as indicated in the figure. [[

]].

Figure 5-6 illustrates the effectiveness of the OPRM approach. The simulated OPRM channels exhibit a total number of confirming cells that is continuously increasing as the event evolves, reaching a CD close to unity when the oscillation amplitude has not shown any significant growth (around 50 seconds). This test demonstrates the CDA capability to provide early detection and suppression signal. In addition, it successfully demonstrates the use of OPRM cells as the source of signal to the CDA.

In addition, the CDA was applied to selected TRACG power traces in Section 4, which demonstrated the algorithm capability to recognize the instability inception [[

]]

5.4 SETPOINT METHODOLOGY APPLICABILITY

The DSS-CD relies on several setpoints for its oscillation detection algorithms. These setpoints are classified into three distinct groups:

a. CDA setpoints,

b. Defense-in-depth algorithms setpoints, and

c. Armed region setpoints.

[[

]]

5.4.1 CDA Setpoints

The CDA includes trip and alarm setpoints, which are assigned discrete values. They include the successive confirmation count threshold (N_{Th}), CDA alarm setpoint (N_{Al}), and confirmation density setpoint (S^{j}_{CD}).

N_{Th} is a generic, predetermined discrete setpoint [[ ]]. Its purpose is to provide early recognition of OPRM cell oscillatory behavior. For a well-developed oscillatory behavior at the instability threshold and inception, the successive period count is an unambiguous process. In addition, based on actual experience and simulation of instability events, N_{Th} is selected well below the count range associated with SLMCPR violation.

The alarm setpoint, N_{Al}, is selected on a plant and cycle-specific basis and is based on plant-specific operational objectives and preferences.

S^{j}_{CD} is used to generate a trip signal based on a limited number of OPRM cells exhibiting oscillatory behavior. For a well-developed oscillatory behavior at the instability threshold and inception, the count of confirming OPRM cells, recognized by the CDA, is a discrete and unambiguous process. In addition, based on actual experience and simulation of instability events, S^{j}_{CD} is selected well below the count range associated with SLMCPR violation.

5.4.2 Defense-in-Depth Setpoints

The defense-in-depth algorithms are based on a generic set of nominal setpoint values, summarized in Table 3-2. The defense-in-depth algorithms are not designed to provide SLMCPR protection.

5.4.3 Armed Region Setpoints

The DSS-CD Armed Region is defined to conservatively bound the operating domain region potentially susceptible to core oscillations. The bounding size of the region is designed to accommodate, on a generic basis, all plant-specific applications within the solution licensing basis generic applicability envelope defined in Tables 4-1 and 4-6. Confirmatory analysis of the decay ratios at the Armed Region boundaries demonstrated large stability margin. Significant instability events are expected only at low core flow and high core power conditions. Operations at lower core power or higher core flow, well within the Armed Region (i.e., approximately 60% core flow, 30% OLTP), may result in a gradual loss of stability margin. For these conditions, early indication of degraded stability margin is available through the alarm feature of the solution. [[

]]

Table 5-1 CSAU Evaluation Methodology

CSAU Step	Step Description	DSS-CD
1	Scenario Specification	[[ ]]
2	Nuclear Power Plant Selection	BWR/3-6
3	Phenomena Identification and Ranking	Addressed in Table 5-2
4	Frozen Code Version Selection	TRACG02A
5	Code Documentation	NEDE-32176P (Reference 8), NEDE-32177P (Reference 9)
6	Determination of Code Applicability	AOO LTR (Reference 7); Additional parameters disposition
7	Establishment of Assessment Matrix	AOO LTR (Reference 7)
8	Nuclear Power Plant Nodalization Definition	Nodalization defined. Plant nodalization study performed
9	Definition of Code and Experimental Accuracy	NEDE-32177P (Reference 9)
10	Determination of Effect of Scale	Full scale data available, addressed in Section 5.2, Item 10
11	Determination of the Effect of Reactor Input Parameters and State	Addressed in Tables 5-2 and 5-4
12	Performance of Nuclear Power Plant Sensitivity Calculations	Addressed in Tables 5-3 and 5-4
13	Determination of Combined Bias and Uncertainty	[[ ]]
14	Determination of Total Uncertainty	DSS-CD bounding calculations demonstrate that FMCPR > SLMCPR

Table 5-2 Phenomena Governing BWR/3-6 Stability Transients

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Table 5-3 Disposition of High Ranked Stability Model Parameters

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Table 5-4 Key Plant Initial Conditions/Parameters

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[[

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Table 5-5 Summary of PBA Testing against Actual Plant Data

Testing Purpose	Data Source	Reference	Retest
Single/Multiple LPRM count response for operational event	LaSalle pump upshift event	2	No
Single/Multiple LPRM count response for stable steady state conditions	Pilgrim stable startup data	2	Yes
Single/Multiple LPRM count response for operational events	Limerick test data (1RPT, 2RPT, turbine stop valve, pressure regulator, feedwater flow step change, recirculation flow step)	2	No
Single/Multiple LPRM count response for regional instability event	KKL Cycle 1 instability events	2	No
Single/Multiple LPRM count response for regional instability event	KKL Cycle 7 instability events	2	Yes
Single/Multiple LPRM count response for regional instability event	Coarso instability data (regional)	2	No
OPRM count response for regional instability event	KKL Cycle 7 instability events	2	Yes
OPRM count response for core wide instability event	Limerick Cycle 1	2	No

Table 5-6 Summary of CDA Testing against Actual Plant Data

Testing Purpose	Data Source
Multiple LPRM count response and timing for regional instability test event	KKL Cycle 7 instability event (STAB5)
Multiple LPRM and OPRM count response and timing for core wide instability event	Columbia Cycle 8 instability event

Figure 5-1 Example LPRMs Performance for KKL Cycle 7 Instability Test (STAB5)

[[

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Figure 5-2 CD Performance for KKL Cycle 7 Instability Test (STAB5)

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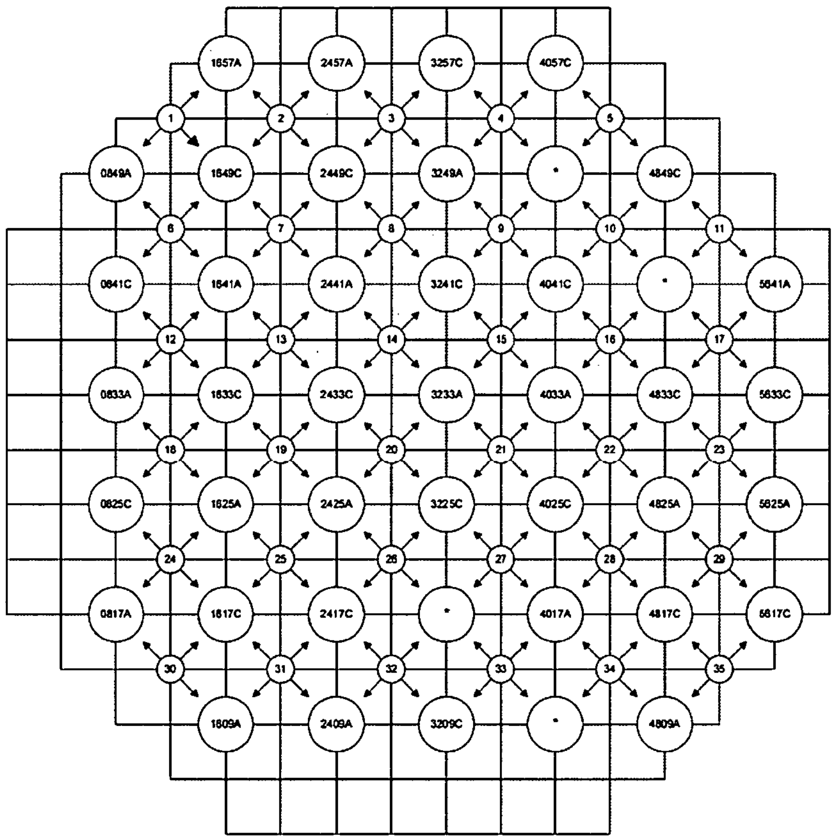
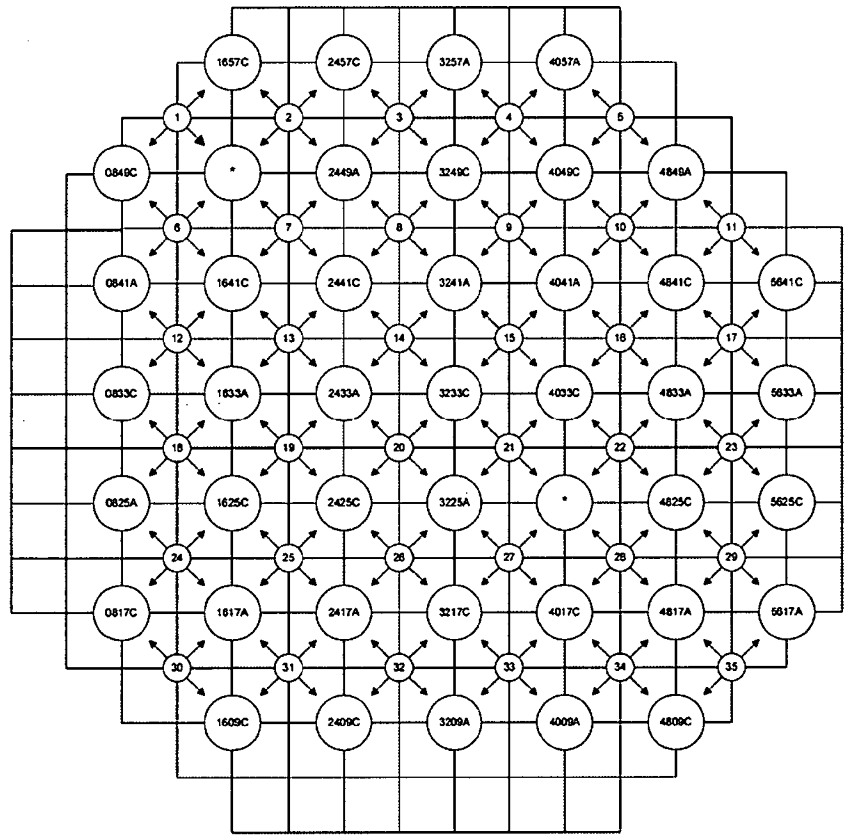
Figure 5-3 Columbia LPRM/OPRM Assignment Map Demonstration



*Data not available

764 Bundle Core, OPRM Channel 1



*Data not available

764 Bundle Core, OPRM Channel 2

Figure 5-4 Example LPRM/OPRM Performance for Columbia Cycle 8 Instability Event

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Figure 5-5 LPRM CD Performance for Columbia Cycle 8 Instability Event

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Figure 5-6 OPRM CD Performance for Columbia Cycle 8 Instability Event

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6.0 PLANT SPECIFIC APPLICATION

A plant specific review procedure is established to confirm that the generic DSS-CD licensing basis is applicable to plant-specific designs, including reload designs, and therefore, demonstrating SLMCPR protection by the DSS-CD for anticipated stability related oscillations. If the generic DSS-CD licensing basis is not applicable to a plant specific design, additional analyses will be necessary to demonstrate applicability.

6.1 PLANT SPECIFIC REVIEW PROCESS

The generic DSS-CD licensing basis allows solution implementation for GE BWR/3-6 product lines and existing GE fuel designs. The solution provides for early instability detection and suppression with minimal degradation in CPR performance during anticipated instability events. The resulting inherent CPR margin to the SLMCPR is expected to accommodate future evolution in fuel cycle designs and operating flexibility features that may affect stability performance.

The standard plant specific review process, which also applies to the reload process, consists of an applicability checklist, confirming that the generic applicability envelope, as defined in Section 4.0, is not exceeded. The plant specific applicability checklist is provided in Table 6-1 for TLO and in Table 6-2 for SLO.

If any checklist criterion is not met as a result of a plant specific design change that may affect reactor stability performance, the DSS-CD plant specific procedure will be performed to demonstrate adequate SLMCPR protection. If the design change is either within the DSS-CD plant specific applicability checklist envelope or does not affect the reactor stability performance, no additional DSS-CD applicability demonstration analysis is required.

Any extension of the DSS-CD applicability envelope requires confirmation analysis based on the methodology outlined in Section 4.0. In Section 4.0, the [[

]] The DSS-CD procedure uncertainty (or equivalent), documented in Section 4.0, is then applied to confirm the margin to the SLMCPR. The DSS-CD applicability extension procedure is summarized in Table 6-3 for TLO and in Table 6-4 for SLO.

Design changes beyond the DSS-CD plant specific applicability checklist envelope that affect stability performance will require confirmation analysis according to the DSS-CD applicability extension procedures of Tables 6-3 and 6-4. [[

]]

If the DSS-CD applicability extension involves a new GE fuel design beyond GE14 or non-GE fuel designs, then Table 6-5 is applied. The table lists the possible fuel design transitions among approved and unapproved GE and non-GE fuel designs for DSS-CD applications. The table specifies the required [[

]]

6.2 LEAD USE ASSEMBLY

For a typical reload core, single channel oscillations are not probable because unstable channel condition is approached by a large number of channels, leading to significant core participation in the ensuing instability. However, the introduction of lead use assemblies (LUA) in a reload core creates the possibility of a unique thermal-hydraulic behavior, potentially leading to single channel oscillations. The DSS-CD solution provides early detection for such situations through its alarm function and eventual trip signal in the event of significant oscillation magnitude through its defense-in-depth protection features. When a limited number of LUAs is introduced to a reload core, the LUA thermal-hydraulic performance and stability characteristics will be assessed to determine potential susceptibility to single channel oscillations.

Table 6-1 TLO DSS-CD Plant Specific Applicability Checklist

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Table 6-2 SLO DSS-CD Plant Specific Applicability Checklist

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Table 6-3 TLO DSS-CD Applicability Extension Evaluation Procedure

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Table 6-4 SLO DSS-CD Applicability Extension Evaluation Procedure

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Table 6-5 Required TRACG Cases for Fuel Design Transition Scenarios

[[

]]

7.0 BACKUP STABILITY PROTECTION

7.1 INTRODUCTION

This section provides a description of Backup Stability Protection (BSP) approaches that may be used when the OPRM system is inoperable, applicable up to and including operation in the MELLLA+ domain. The elements of the BSP are confirmed on a plant and cycle specific basis to provide consistency with the LTS general requirement of long-term applicability. Other NRC approved backup approaches that are justified to provide appropriate protection may also be implemented.

Two BSP options are presented in this section and summarized in Section 7.5. Both options provide adequate protection for continued operation in the unlikely event the DSS-CD licensing basis algorithm cannot be demonstrated to provide its intended SLMCPR protection. The sections below discuss the three constituents of the two options, which are:

Manual BSP Regions	Comprises plant-specific regions (Scram and Controlled Entry) in the licensed power-flow operating domain and specified manual operator actions. The basis for the Manual BSP Regions is presented in Section 7.2, Manual BSP Region Boundaries Generation
BSP Boundary	Defines the operation domain where potential instability events can be effectively addressed by specified operator actions. Its basis is presented in Section 7.3, BSP Boundary Generation
Automated BSP Scram Region	Comprises an automatic reactor scram region implemented by the APRM flow-biased scram setpoint. Its basis is presented in Section 7.4, Automated BSP Scram Region Generation

7.2 Manual BSP Region Boundaries Generation

The DSS-CD Manual BSP Regions use the GE/BWROG Interim Corrective Actions (ICAs) regions presented in Reference 5 as a starting point. The following elements are included in the Manual BSP Region generation process:

- The size of the base (minimal) Manual BSP Regions is equivalent to the current ICA regions,
- The three ICA regions (Scram, Exit, Controlled Entry) are replaced by two Manual BSP Regions (Scram and Controlled Entry),
- Common decay ratio criteria are established for plant and cycle-specific confirmation, and as necessary, the base Manual BSP Regions are increased to satisfy these criteria,
- The Manual BSP Regions are established based on two intercept state points, one on the High Flow Control Line (HFCL) and the other on the Natural Circulation Line (NCL), which are connected by the Generic Shape Function (GSF). When confirming the Manual BSP Regions for MELLLA+ operation, the HFCL is defined as the MELLLA+ upper boundary above 55% core flow and its extension to the NCL. The NCL is defined as the plant specific natural circulation line,
- The manual BSP regions is developed considering the appropriate feedwater temperature, including reduced feedwater temperature operation,
- Operator actions in the two Manual BSP Regions are similar to the operator actions currently defined for the ICA Scram and Controlled Entry regions,
- Operator awareness is required when operating within 10% of rated core flow or power from the Manual BSP Controlled Entry region.

Figure 7-1 illustrates the base Manual BSP Regions relative to the ICA regions. For uprated plants, the ICA region boundaries are scaled to maintain the pre-uprate region boundaries absolute power and flow values, which is then used to generate the base Manual BSP Regions, following the process illustrated in Figure 7-1.

7.2.1 Generic Shape Function

The Generic Shape Function (GSF) is a fit to power/flow state points representing a constant decay ratio. The GSF procedure is applied to two state points that meet specified region boundary generation stability criteria, one on the HFCL and the other on the NCL. The region boundary is defined with the GSF as:

$$P = P_B \left(\frac{P_A}{P_B} \right)^{\frac{1}{2}\left[\frac{W - W_B}{W_A - W_B} + \left(\frac{W - W_B}{W_A - W_B} \right)^2 \right]}, \qquad W \geq W_B$$

where:

Point A: Intersection of the HFCL and specified core flow,

Point B: Intersection of the NCL and specified load line,

P: Core power in % rated

W: Core flow in % rated.

If core flow rates below W_B are assessed, the generic shape function slope may become negative when the quadratic exponential term dominates. Typically, this situation is not expected to occur because the flow range below W_B is limited. In the unlikely situation where negative slope below W_B is encountered, a modified form of this function is used. To ensure both a positive slope and continuity below W_B, the quadratic exponential term is eliminated and the following function is used:

$$P = P_B \left(\frac{P_A}{P_B} \right)^{\frac{1}{2}\left[\frac{W - W_B}{W_A - W_B} \right]}, \qquad W < W_B$$

7.2.2 Base Manual BSP Regions Derivation

The base Manual BSP Regions are generated based on the minimal requirements of the original ICA regions using the GSF as illustrated in Figure 7-1. The base Manual BSP Regions are established on a plant specific basis based on the generic process outlined below.

The base Manual Scram Region (Region I) boundary is generated by applying the GSF to Points A and B:

Point A: Intersection of the MELLLA upper boundary and 40% rated core flow,

Point B: Intersection of the NCL and 100% OLTP load line,

The base Manual BSP Region I boundary is extrapolated up to the extension of the MELLLA+ HFCL through the application of the GSF for core flows above 40%.

The base Manual BSP Controlled Entry Region (Region II) boundary is generated by applying the GSF to Points A' and B':

Point A': Intersection of the MELLLA upper boundary and 50% rated core flow,

Point B': Intersection of the NCL and 70% OLTP load line,

The base Manual BSP Region II boundary is defined only up to the MELLLA upper boundary.

The base manual BSP regions for MELLLA+ operation are illustrated in Figure 7-2.

The base manual BSP region boundaries define the minimum region size required.

7.2.3 Manual BSP Regions Plant Specific Application

The process defining the plant and cycle-specific manual regions is described in this section.

7.2.3.1 Region I – Manual BSP Scram Region

Region Definition

The Manual BSP Region I boundary is established by applying the GSF to Points A (along the HFCL) and Point B (along the NCL). Each point is selected based on the more limiting of the following options:

1. The base minimal region.
2. A best-estimate stability calculation using the ODYSY frequency domain code (Reference 6) with the calculation procedure outlined in Table 7-1 for Manual BSP Region I and the

stability criterion associated with 0.8 core and channel decay ratios, as illustrated in Figure 7-3.

If the best-estimate calculation results at both points are bounded by the base minimal region, the base minimal region is confirmed. If the best-estimate calculation results exceed the base minimal region at any point, the base minimal region is extended at that point.

For MELLLA+, the Manual BSP Region I boundary is extended outside the operating domain upper boundary (i.e., MELLLA) up to the extension of the HFCL, to ensure proper operator action upon unplanned entry into the region. Figure 7-4 illustrates the process for establishing manual BSP boundaries for an example BWR/6. For this example the continued applicability of the base Manual BSP Region I is confirmed.

<u>Actions</u>

An immediate manual scram is required upon determination that the region has been entered. If entry is unavoidable, early scram initiation is appropriate.

7.2.3.2 Region II – Controlled Entry Region

<u>Region Definition</u>

The Manual BSP Region II boundary is established by applying the GSF to Points A' (along the HFCL) and Point B' (along the NCL). Each point is selected based on the more limiting of the following options:

1. The base minimal region.
2. A best-estimate stability calculation using the ODYSY frequency domain code (Reference 6) with the calculation procedure outlined in Table 7-1 for Manual BSP Region II and the stability criterion associated with 0.8 core and channel decay ratios (illustrated in Figure 7-3) applied to point B' and the stability criterion associated with 0.6 core and channel decay ratios (also illustrated in Figure 7-3) applied to point A'. The 0.6 criterion is used for point A' rather than 0.8 to provide additional stability margin for operation at off-rated conditions.

If the best-estimate calculation results at both points are bounded by the base manual BSP minimal region, the base manual BSP region is confirmed. If the best-estimate calculation results exceed the base manual BSP minimal region at any point, the base manual BSP region is extended at that point.

The Manual BSP Region II boundary is defined by the GSF inside the licensed operating domain. Unlike the Manual BSP Region I boundary, extension of Manual BSP Region II boundary outside the MELLLA upper boundary for the core flow range below the MELLLA+ operating domain extension is not necessary. This is because immediate corrective operator action is required for unplanned operations at reactor power levels exceeding the licensed values. Figure 7-4 illustrates the process for establishing BSP boundaries for an example BWR/6. For this example the continued applicability of the base Region II is confirmed.

Actions

- If the entry is inadvertent or forced, immediate exit from the region is required. The region can be exited by control rod insertion or core flow increase by pump speed increase for Motor Generator (MG) set plants or flow control valve (FCV) opening for FCV plants. Increasing the core flow by either restarting or upshifting (for FCV plants) a recirculation pump is not an acceptable method of exiting the region.
- Deliberate entry into the Manual BSP Controlled Entry Region requires compliance with at least one of the stability controls outlined below:
  - Maintain core average Boiling Boundary (BB) ≥ 4.0 feet,
  - Maintain core decay ratio (DR) < 0.6 as calculated by an on-line core stability monitor,
  - Determine appropriate limits for core DR (< 0.60) as calculated by a core stability monitor or by pre-analysis of a reactor state trajectory through the Manual BSP Controlled Entry Region, or
  - Continuous dedicated monitoring of real time control room neutron monitoring instrumentation with manual scram required upon indication of a reactor instability induced power oscillation.

- The guidance and actions recommended by the BSP emphasize instability prevention to minimize the burden placed on the operator when monitoring for the onset of power oscillations. Therefore, caution is required whenever operating near the Manual BSP Region II boundary (i.e., within approximately 10% of core power or core flow), and it is recommended that the amount of time spent operating near this region be minimized.

7.3 BSP BOUNDARY GENERATION

The BSP Boundary delineates that portion of the core power and flow operating domain that is not expected to be susceptible to instability events associated with a high initial growth rate. These instability events if developed can be recognized by the operator sufficiently early to allow timely manual power suppression prior to significant MCPR degradation. [[

]] Therefore, operation above the BSP Boundary is not permitted.

7.3.1 BSP Boundary Plant Specific Application

Boundary Definition

The BSP Boundary is defined by connecting Point A" (at power condition) and Point B" (along the NCL) as illustrated in Figure 7-5. [[

]] This is illustrated in the example BSP Boundaries provided below.

Figure 7-5 illustrates a BSP Boundary for an example BWR/6. [[

]] any flow reduction event from off-rated conditions that is terminated inside the Manual BSP Region I, including all events terminating above the OLTP 100% load line, requires immediate operator action to manually scram the reactor.

Only those portions of the BSP Boundary that traverse the core power and flow licensed operating domain outside the Manual BSP Scram Region are explicitly identified on the operating map. The Manual BSP Controlled Entry Region boundary is extended to the appropriate licensed operating domain upper boundary. If any portion of the BSP Boundary traverses the Manual BSP Scram Region, this portion is not explicitly identified because operation inside the Manual BSP Scram Region requires an immediate action to scram the reactor, which is controlling.

Figures 7-6 through 7-8 illustrate BSP Boundaries for additional examples, comprising of different BWR/4 plants. Table 7-3 provides a summary of the four BSP Boundary examples. [[

]]

Actions

Operation above the BSP Boundary requires immediate initiation of actions to lower the reactor power to below the BSP Boundary by control rod insertion.

7.4 AUTOMATED BSP SCRAM REGION GENERATION

The Manual BSP Scram Region, which requires an immediate manual scram upon determination that the region has been entered, may be automated by extending the APRM flow-biased scram setpoint to encompass the region. Because the Manual BSP Scram Region boundary intersection with the plant specific NCL is not higher than the intersection of the original 100% load line with the plant NCL, flow reduction events from the MELLLA+ region to the NCL would result in an entry into the Automated BSP Scram Region, and therefore an automatic reactor scram.

Automating the Manual BSP Scram Region provides an adequate instability prevention protection for operation in the entire MELLLA+ domain for interim situation when the CDA protection is temporarily unavailable. However, such a protection requires plant specific system modifications that may include hardware and/or software changes. This feature may be implemented based on plant specific considerations of the added benefits of continued operation in the MELLLA+ domain versus the added cost associated with the necessary system modifications.

Figures 7-9 and 7-10 illustrate the [[

]]

7.4.1 Automated BSP Scram Region Plant Specific Application

<u>**Region Definition**</u>

The APRM flow-biased scram setpoint is extended to encompass the Manual BSP Region I boundary, defined in Section 7.2. [[

]]

The Automated BSP Scram Region is [[

]] any flow reduction event initiating from off-rated conditions and terminating inside the Automated BSP Scram Region, including all events terminating above the OLTP 100% load line, results in immediate automatic reactor scram.

Figure 7-11 illustrates the construction of the modified APRM flow-biased scram setpoints, including the Automated BSP Scram Region. The figure also illustrates the APRM flow-biased rod block setpoints, which are constructed to provide the standard scram avoidance protection. [[

]]

Because a plant cycle specific assessment is required to confirm the applicability or update the Manual BSP Region I boundary, the Automated BSP Scram Region is also required to be confirmed or updated.

<u>Actions</u>

There are no required operator actions associated with the Automated BSP Scram Region since an automatic reactor scram is initiated upon entry.

7.5 BSP OPTIONS APPLICATION SUMMARY

Two BSP options are described in this section, which may be used in the unlikely event the OPRM system is inoperable. They both provide effective SLMCPR protection.

7.5.1 BSP Option 1

This option comprises manually implemented region boundaries (Scram and Controlled Entry Regions) and specified manual operator actions, as described in Section 7.2, Manual BSP Region Boundaries Generation, and restrictions in the allowable operating domain as described in Section 7.3, BSP Boundary Generation. Figure 7-12 illustrates this option for the BWR/4 example of Figure 7-6.

In Figure 7-12, the Manual BSP Region I is the same as the base Manual BSP Region I since the base region is confirmed, as illustrated in Figure 7-6. The Manual BSP Region II in Figure 7-12 is larger relative to the base Manual BSP Region II shown in Figure 7-6 as a result of the conservative stability criteria applied at its high end, thus illustrating the added measure to ensure higher stability margin for off-rated operation below the BSP Boundary.

7.5.2 BSP Option 2

This option comprises the Automated BSP Scram Region implemented by the APRM flow-biased scram setpoint, as described in Section 7.4, Automated BSP Scram Region Generation, and the Manual BSP Controlled Entry Region and associated manual operator actions, as described in Section 7.2.3.2, Region II – Controlled Entry Region. The Manual BSP Region II boundary and actions are the same for both BSP Options 1 and 2 and the Manual BSP Region I is not required for BSP Option 2. Figure 7-13 illustrates this option for the BWR/4 example of Figure 7-6. For this option, the APRM flow-biased setpoints may intersect the Manual BSP Region II. In this case, the required operator actions for the Manual BSP Region II is further restricted by the APRM flow-biased setpoints.

7.5.3 BSP Reload Application

A plant cycle specific assessment is required to confirm the applicability or update the BSP option for reload-specific fuel, core design, and operating strategy. [[

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A conservative representation of the Manual BSP Regions, BSP Boundary or Automated BSP Scram Region may be established to minimize the need for cycle-specific updates.

Implementation of a BSP option will require plant specific Technical Specifications (TS) changes and associated justifications. Section 8.0 discusses the recommended TS and Bases changes. Approved setpoint calculation methodology will be applied to the APRM flow-biased setpoints in order to define the allowable values as a function of the reactor recirculation drive flow. The Manual BSP Regions, BSP Boundary, and APRM flow-biased setpoints associated with the Automated BSP Scram Region will be defined in the COLR.

Table 7-1 Manual BSP Regions Calculation Procedure

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Table 7-2 BSP Boundary Calculation Procedure

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Table 7-3 Summary of BSP Boundary Calculation Examples

Example No.	Figure No.	Description
1	7-5	BWR/6, Nominal feedwater temperature
2	7-6	BWR/4, Nominal rated feedwater temperature
3	7-7	BWR/4, Reduced rated feedwater temperature (- 23°F)
4	7-8	BWR/4, Reduced rated feedwater temperature (- 55°F)

Note: Examples 2 through 4 comprise of different BWR/4 plants.

Figure 7-1 Base Manual BSP Regions Generation Basis Relative to ICA Regions (100% EPU = 120% OLTP)

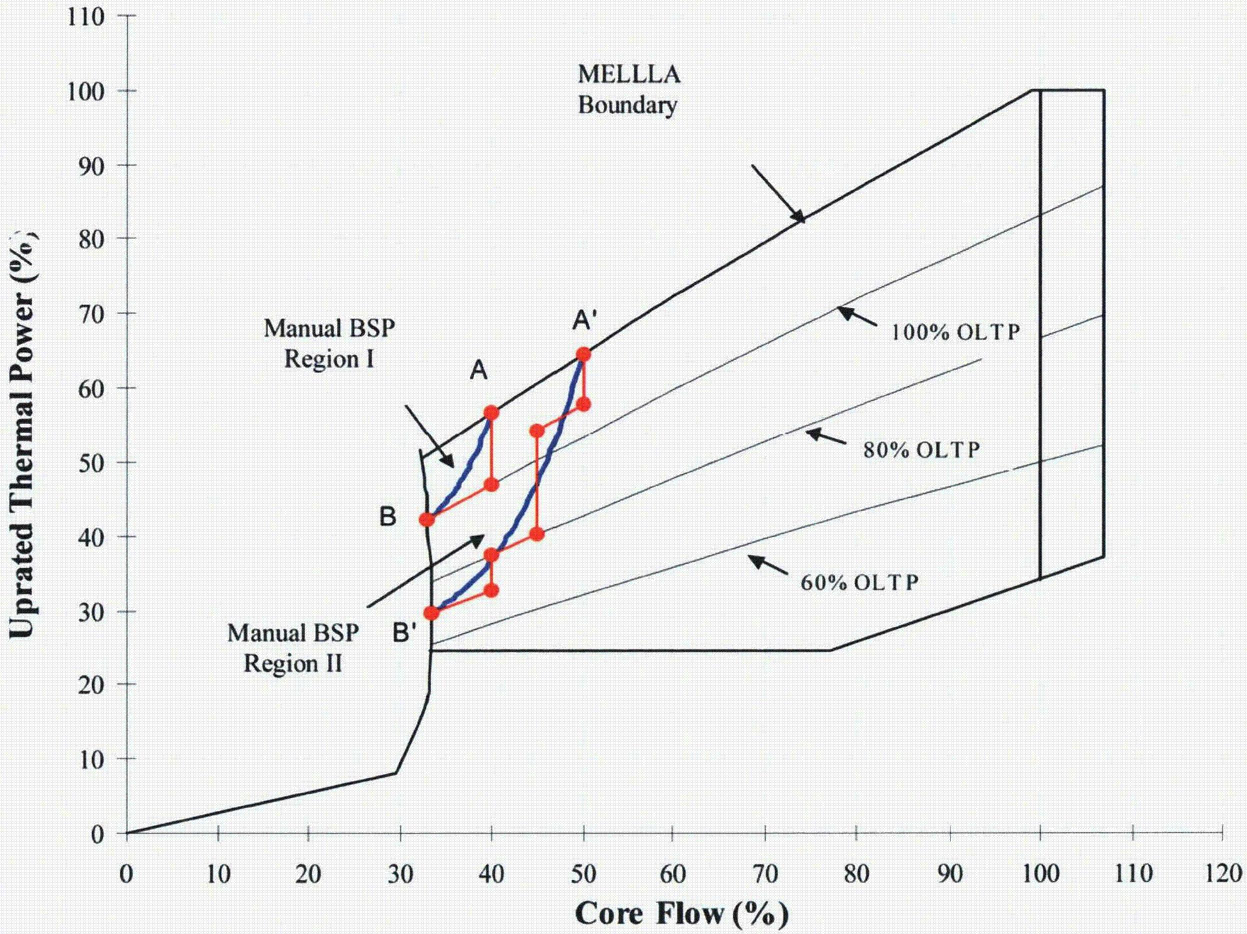

Figure 7-2 MELLLA+ Base Manual BSP Regions
(100% EPU = 120% OLTP)

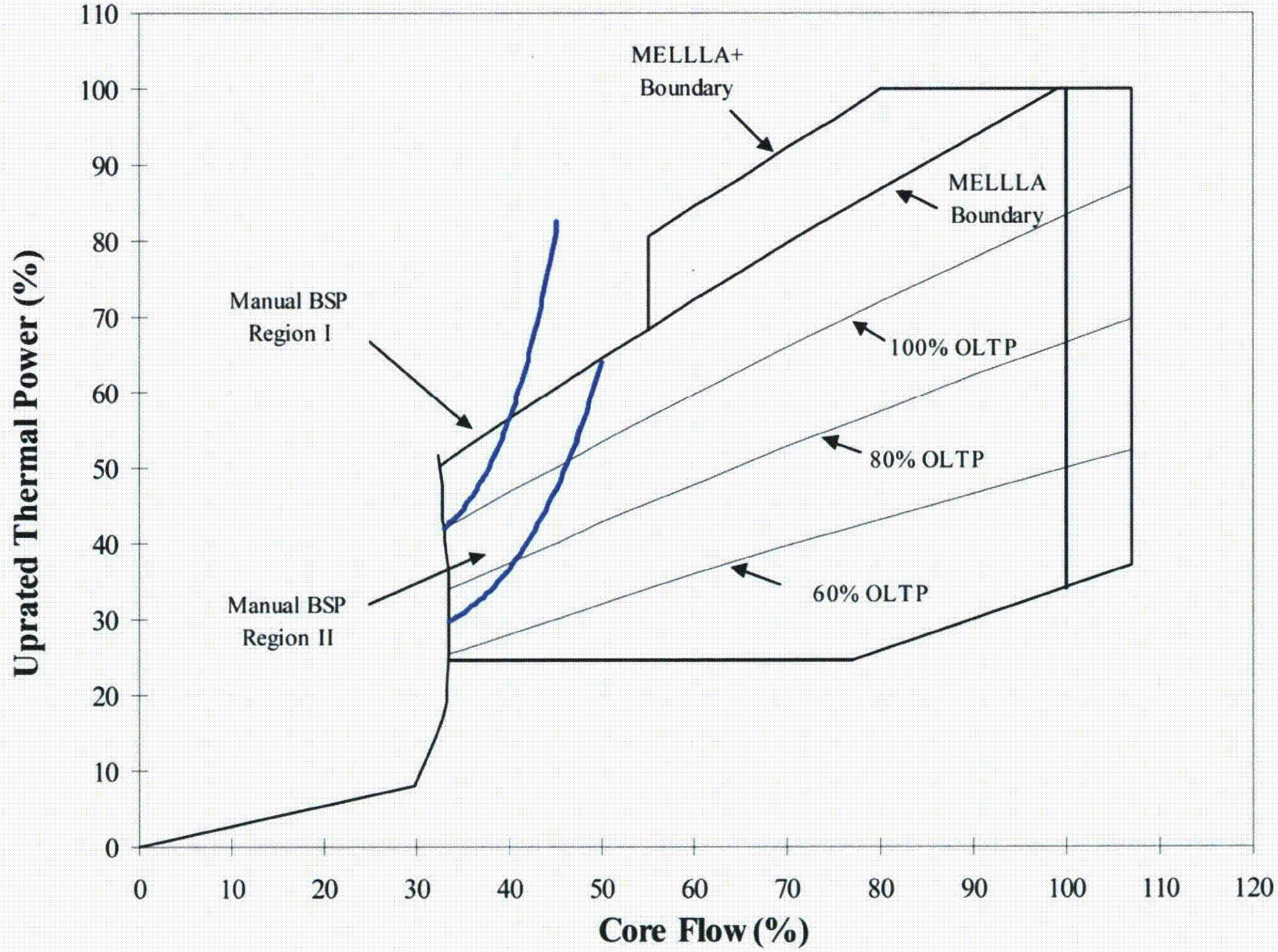

Figure 7-3 Stability Criteria

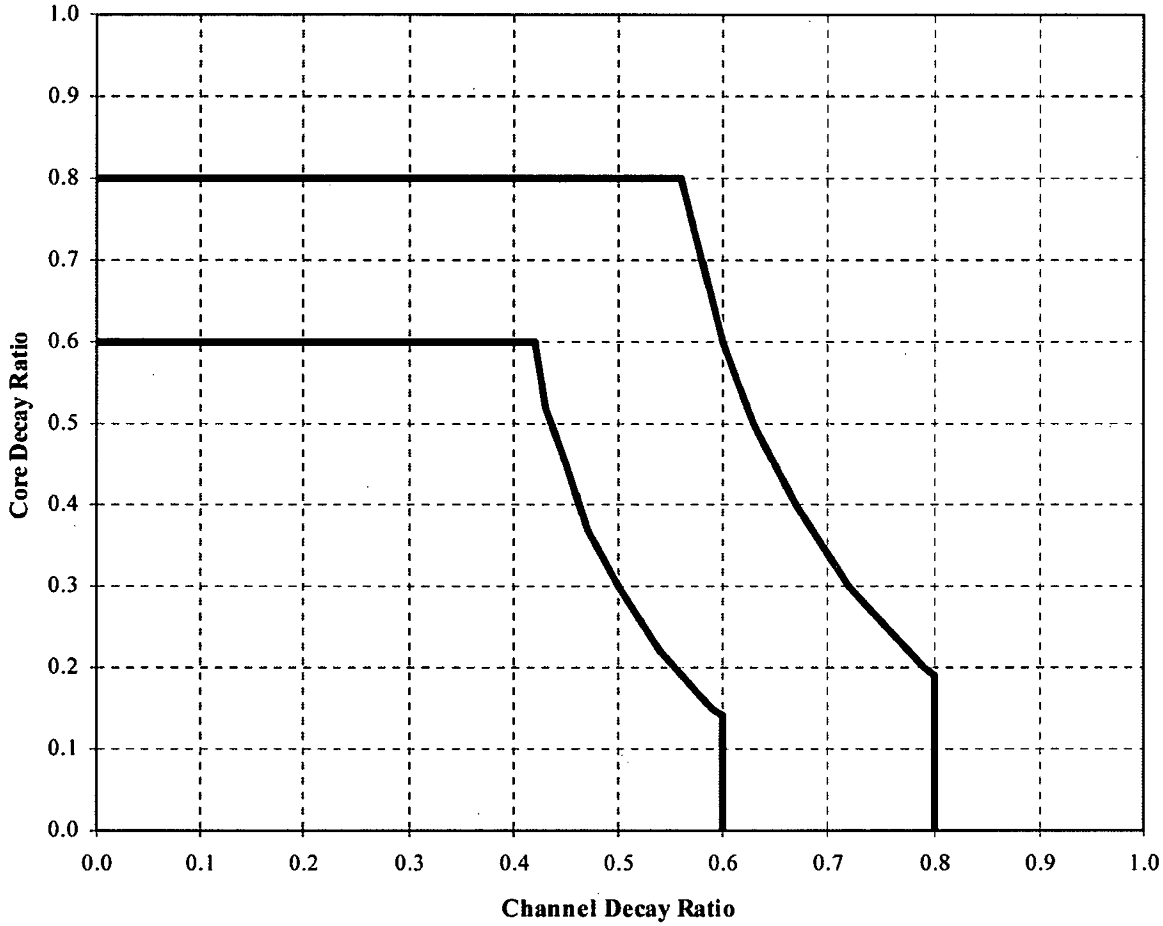

Figure 7-4 Example BWR/6 Manual BSP Regions Confirmation

(100% EPU = 120% OLTP)

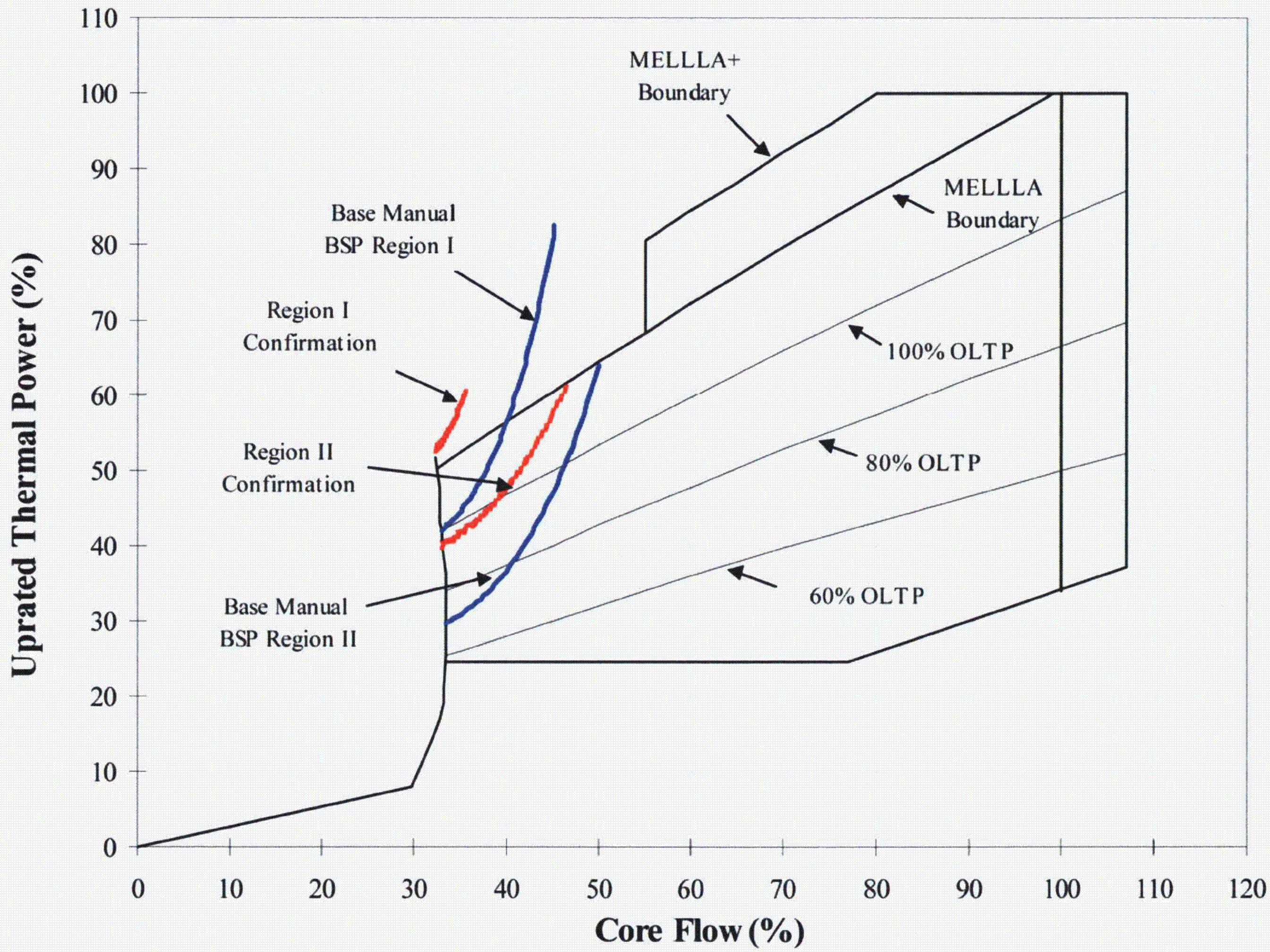

Figure 7-5 Example 1: BWR/6 Manual BSP Region I Confirmation and BSP Boundary

(100% EPU = 120% OLTP, Nominal Feedwater Temperature)

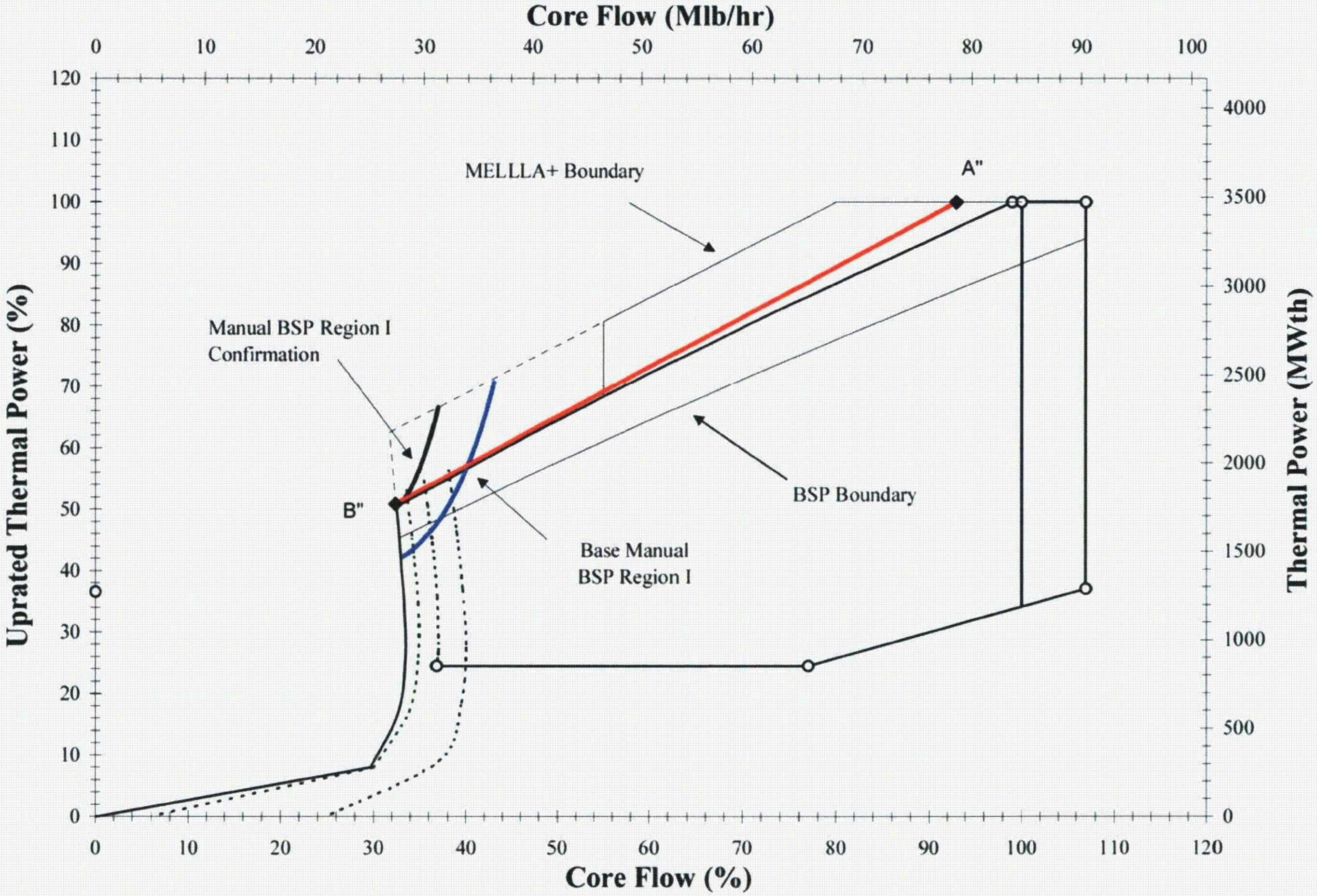

Figure 7-6 Example 2: BWR/4 Manual BSP Region I Confirmation and BSP Boundary

(100% EPU = 120% OLTP, Nominal Feedwater Temperature)

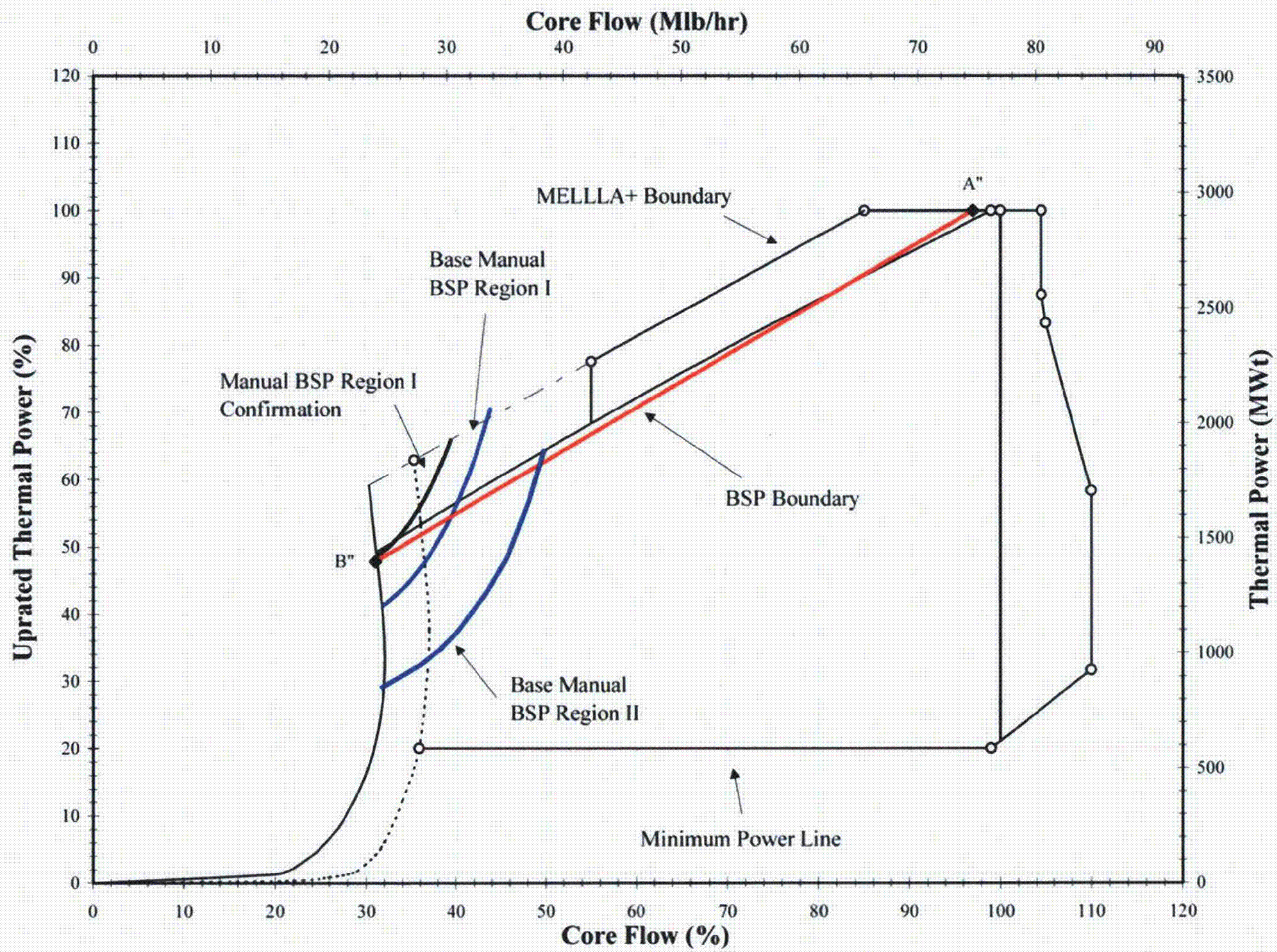

Figure 7-7 Example 3: BWR/4 Manual BSP Region I Confirmation and BSP Boundary

(100% EPU = 120% OLTP, 23°F Feedwater Temperature Reduction)

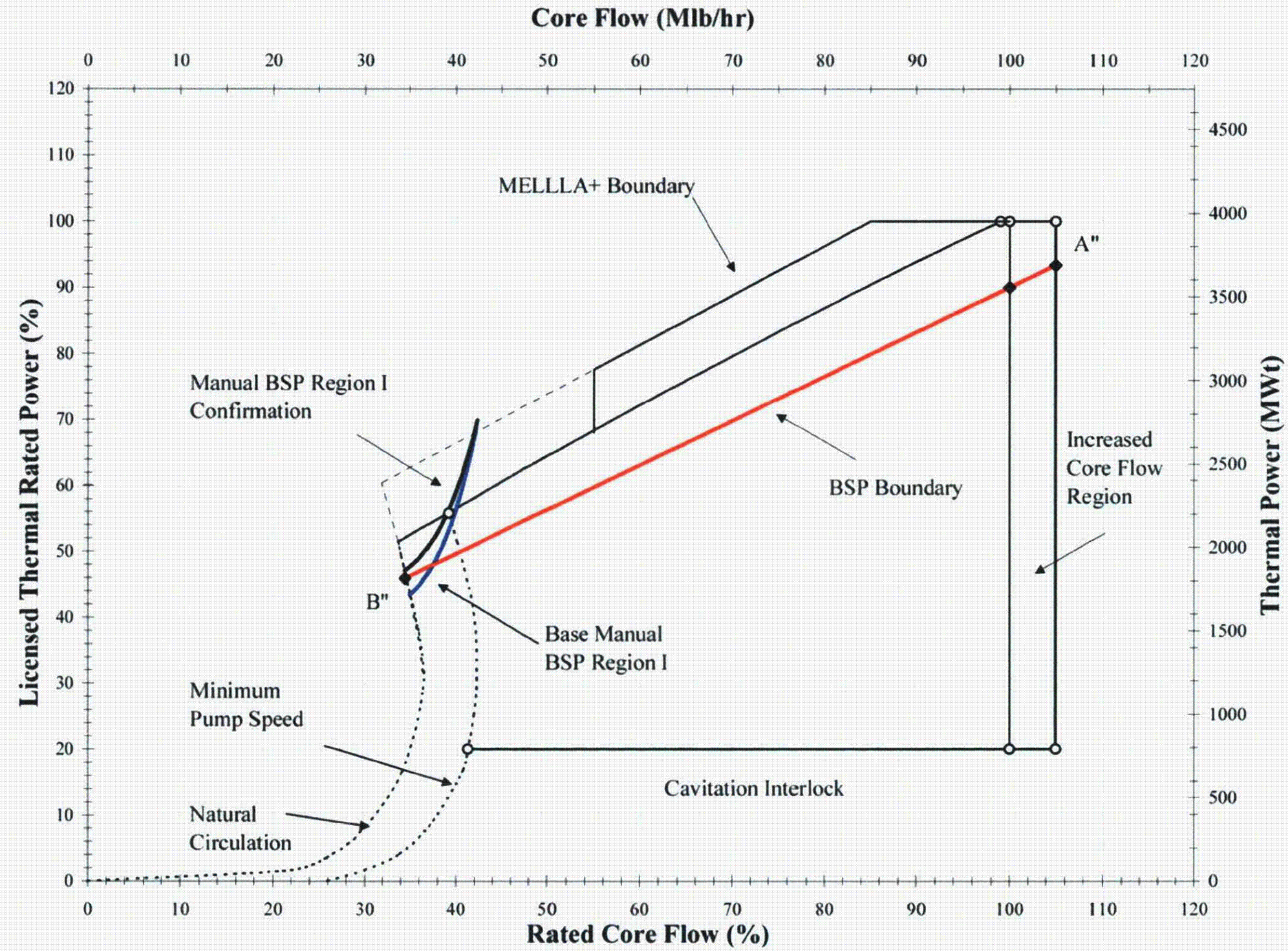

Figure 7-8 Example 4: BWR/4 Manual BSP Region I Confirmation and BSP Boundary

(100% EPU = 120% OLTP, 55°F Feedwater Temperature Reduction)

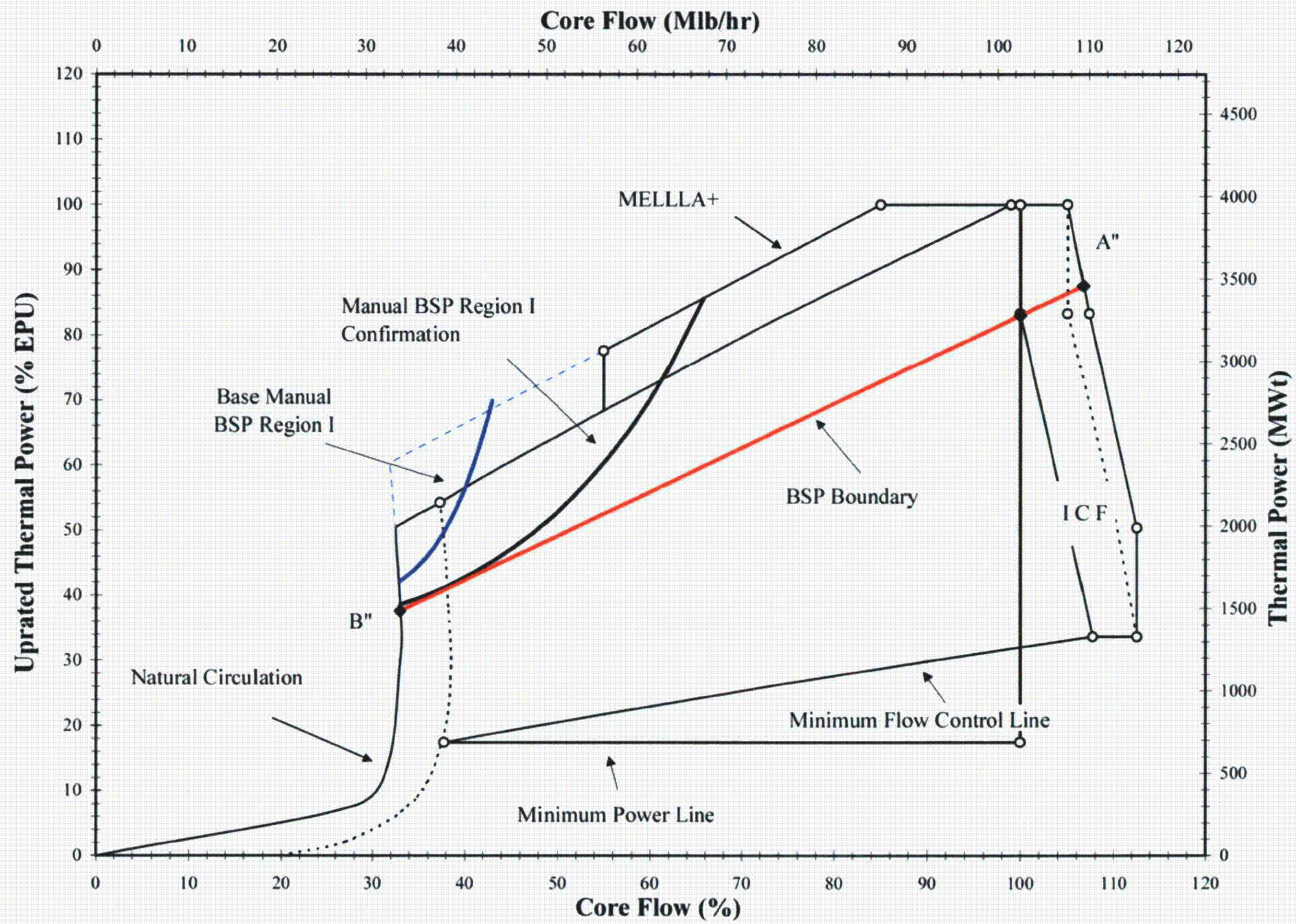

Figure 7-9 Scram Timing Illustration for BSP Option 2 [[ ]]

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Figure 7-10 Scram Timing Illustration for BSP Option 2 [[ ]]

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Figure 7-11 Automated BSP Region I Modified APRM Flow Biased Setpoint Construction

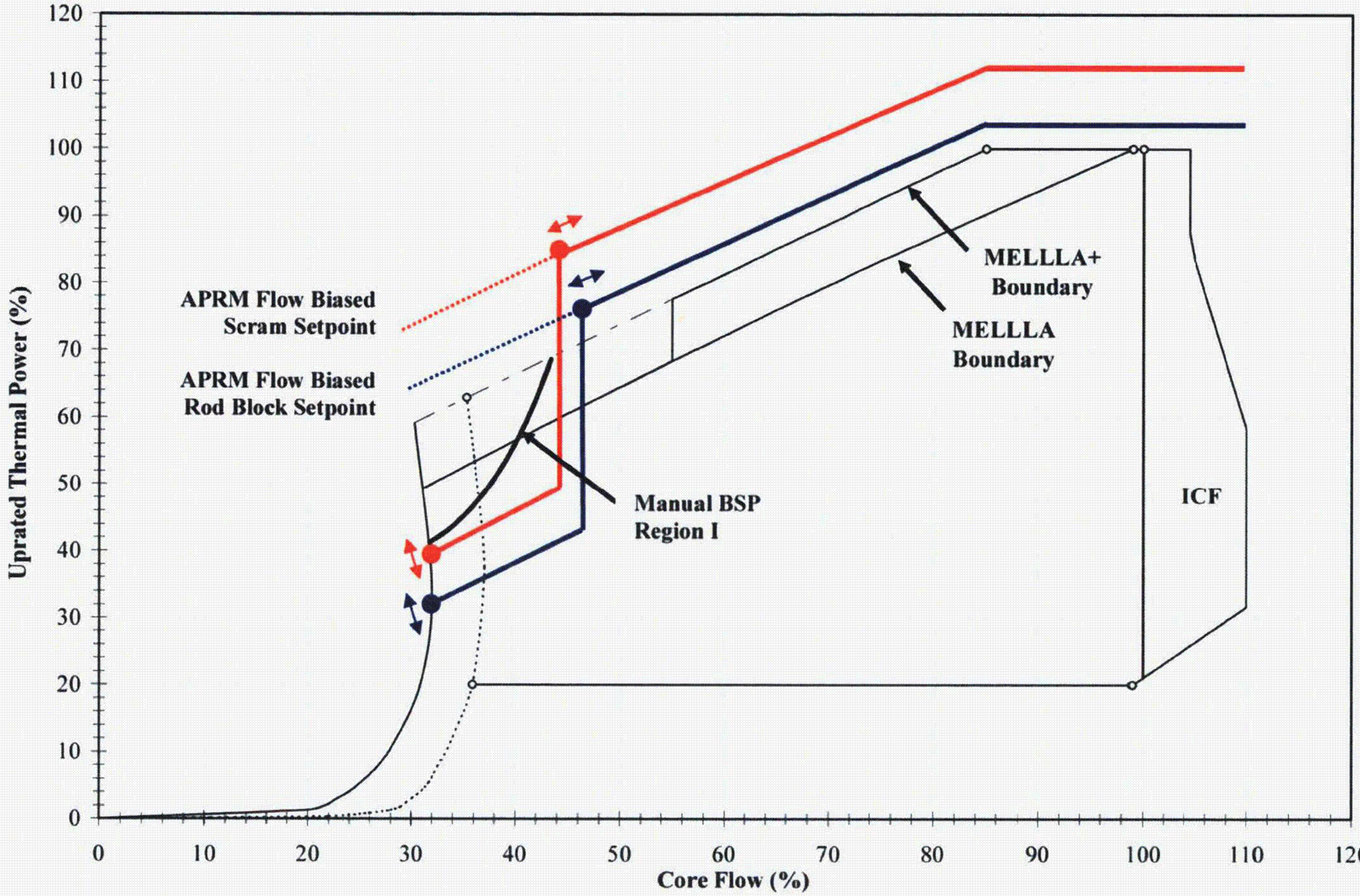


Figure 7-12 BSP Option 1 Illustration

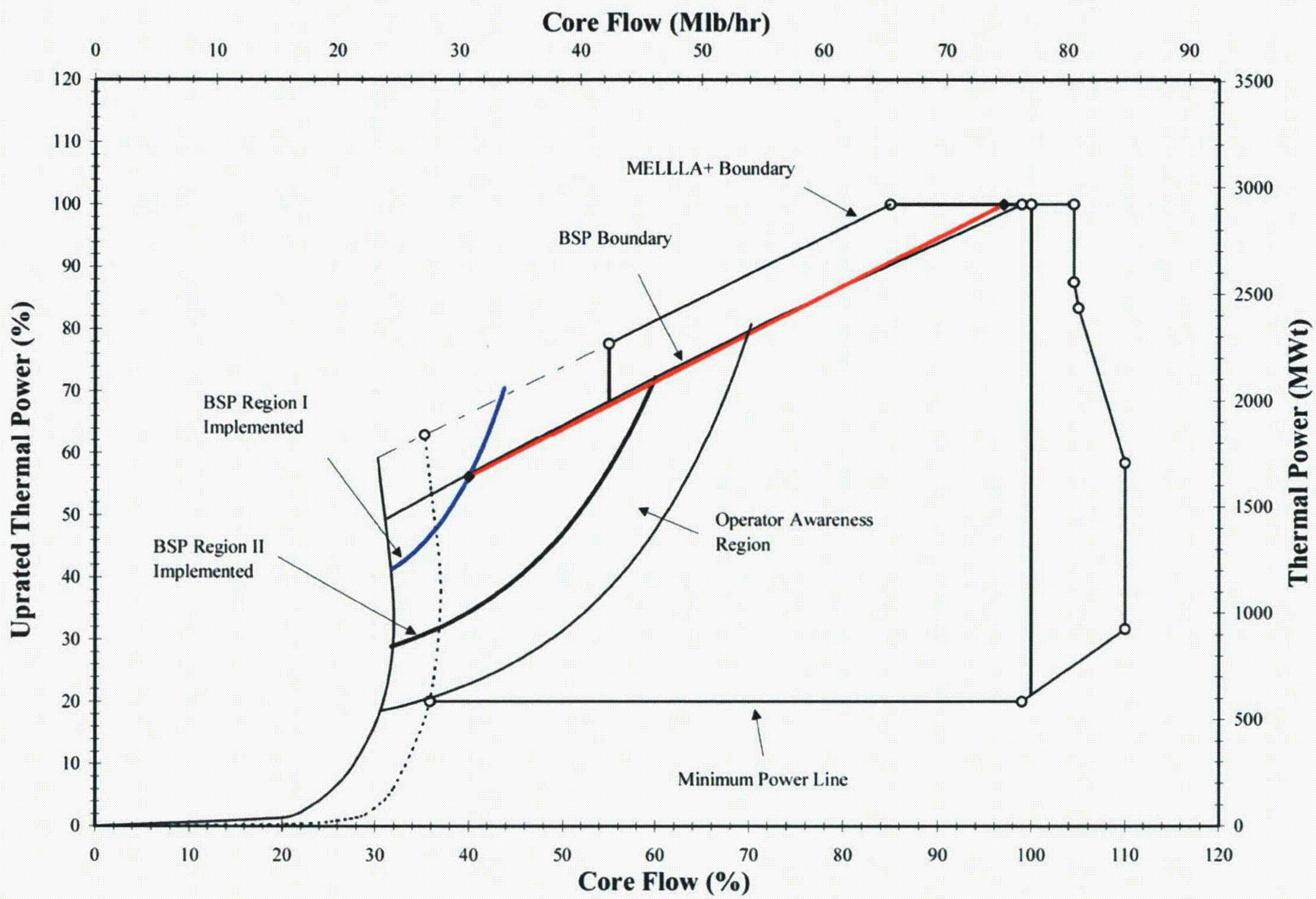
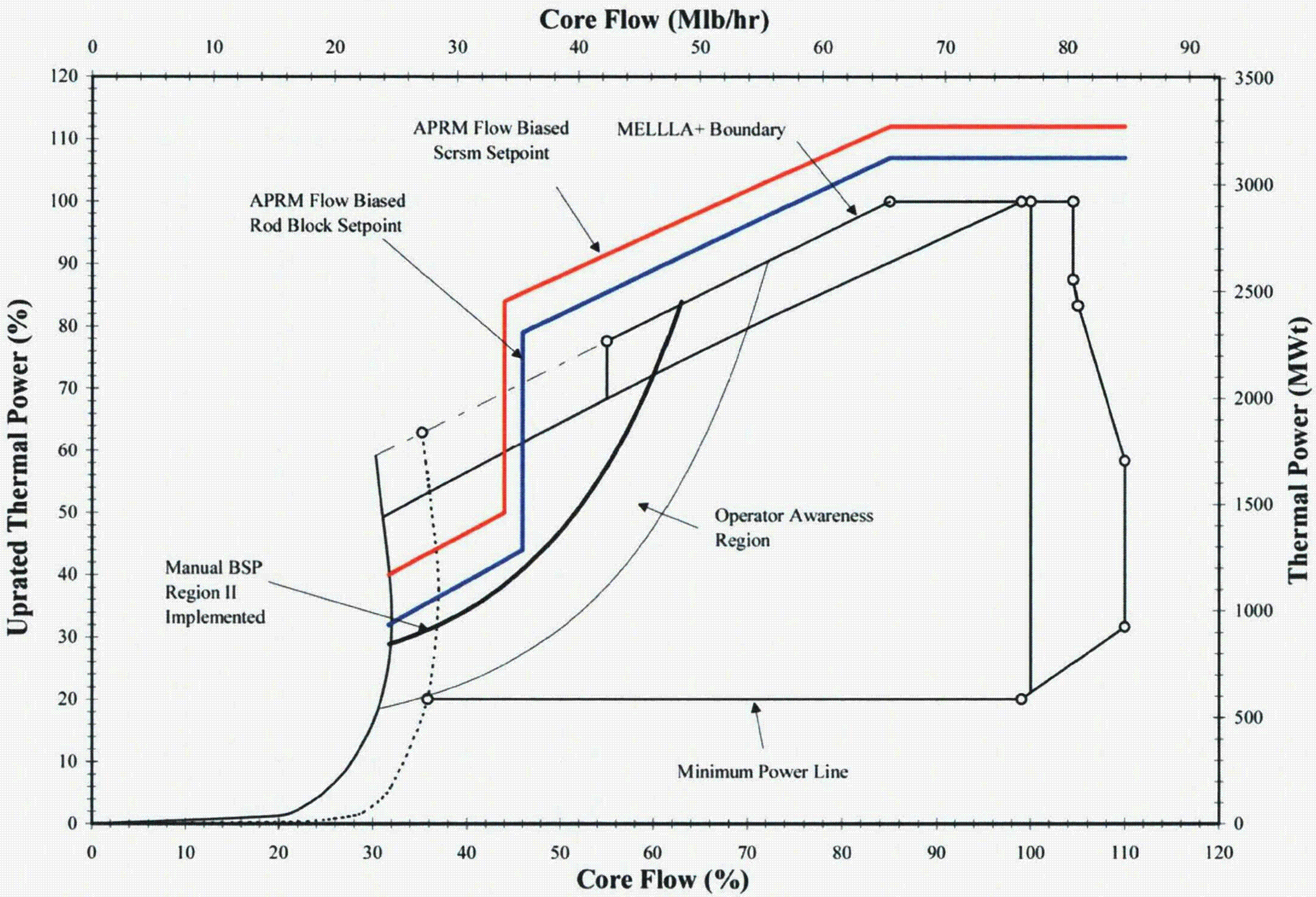


Figure 7-13 BSP Option 2 Implementation



8.0 EFFECT ON TECHNICAL SPECIFICATIONS

Changes to the Technical Specifications (TS) and Bases are required to address the implementation of DSS-CD. This section provides examples of changes to TS and Bases as generic guidance in developing the plant-specific license amendment to address DSS-CD implementation. Differences in plant-specific changes to the TS and Bases from those examples provided herein may be justifiable based on the plant-specific licensing basis and the inclusion of other licensing basis changes in the plant's license amendment request.

The example TS and Bases changes are provided in Appendices A and B. The appendices assume implementation of the TS and Bases proposed in Reference 13 for BWR/4 Standard Technical Specifications, Rev. 1, 4/7/95. Both Appendixes A and B show the same changes to the TS and Bases. The changes in Appendix A are indicated with revision bars in the left margin with deletions shown by a strikeout fonts and additions shown by an underlined font. Appendix B provides an easier to read set of proposed TS and Bases with the incorporated changes indicated by revision bars only. In general, only pages with changes are shown, but in a few cases other pages are included to better show the context.

A summary of the changes in the TS and Bases is as follows:

1. The proposed changes reflect the implementation of the Backup Stability Protection (BSP) in the event that the DSS-CD is inoperable,
2. Changes in the applicability requirements for DSS-CD,
3. Initial operation of the DSS-CD,
4. Elimination of an unnecessary Surveillance Requirement,
5. Additional core operating limits to the Core Operating Limits Report, and
6. Update the applicable references.

Table 8-1 provides a description of the changes in the TS. This description assumes that the changes proposed for the BWR/4 Standard Technical Specifications in Reference 13 are the existing Technical Specifications. The proposed requirements reflect generic guidance to implement DSS-CD. The purpose of each change is presented to provide an understanding of the generic guidance. The individual plant-specific license amendment request will justify and evaluate the adequacy of necessary TS changes based on the plant's unique licensing basis and any other license basis changes.

Table 8-1 Description and Purpose of TS Changes for DSS-CD Implementation

Specification	Existing Requirement	Proposed Requirement	Purpose
TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation			
Required Action I.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	Initiate action to implement the Manual BSP Regions defined in the COLR.	The Manual BSP Region and required actions are described in Section 7.2. The change reflects a portion of the requirements for Backup Stability Protection if OPRM Upscale trip capability is not maintained.
Completion Time I.1	12 hours	Immediately	The purpose of the reduced Completion Time is to reflect the importance of limiting the period of time during which no automatic or alternate capability is in place.
Required Action I.2.1	None	Implement the Automated BSP Scram Region using the modified APRM flow-biased scram setpoints defined in the COLR.	Actions I.2.1 and I.2.2 are required actions both of which are required to be taken in conjunction with Action I.1 when OPRM Upscale trip capability is not maintained. The Automated BSP Scram Region and required actions are described in Section 7.4.
Completion Time I.2.1	None	12 hours	The Completion Time of 12 hours provides the plant operating staff sufficient time for implementation in an orderly manner.
Required Action I.2.2	None	Initiate action in accordance with Specification 5.6.9	Backup Stability Protection is a temporary means for protection against thermal-hydraulic instability events. While an extended period of inoperability does not warrant the shutdown of the plant with an automatic trip capability provided by the Automated BSP Scram Region, a written plan and schedule, with NRC oversight, to restore the required channels to operability provides appropriate management attention.

Specification	Existing Requirement	Proposed Requirement	Purpose
Completion Time I.2.2	None	90 days	The Completion Time of 90 days is adequate to allow time to evaluate the cause of the inoperability and to determine the appropriate corrective actions and schedule to restore the required channels to OPERABLE status.
Required Action J.1	None	Initiate action to implement the Manual BSP Regions defined in the COLR.	See Required Action I.1.
Completion Time J.1	None	Immediately	See Required Action I.1.
Required Action J.2	None	Reduce operation to below the BSP Boundary defined in the COLR.	Both Actions J.2 and J.3 are required in conjunction with Action J.1. If an automatic trip function for instability events is not maintained, operational conditions during which manual operator actions are sufficient must be established. The BSP Boundary and required actions are described in Section 7.3.
Completion Time J.2	None	12 hours	The Completion Time of 12 hours provides the plant operating staff sufficient time for implementation in an orderly manner.
Required Action J.3	I.2 Restore required channels to OPERABLE.	J.3 Restore required channels to OPERABLE. (Same other than re-numbering of the Action)	Purpose unchanged.
Required Action K.1	Reduce THERMAL POWER to < [25]% RTP.	Reduce THERMAL POWER to less than [20]% RTP or be in Mode 2.	The intent is to place the plant in a condition to which the LCO does not apply. A choice of different applicability requirements is provided, one of which would be proposed in the plant specific application. Either of the two choices represents regions of power-flow operation with minimal susceptibility to thermal-hydraulic oscillations. The [20]% RTP is a plant-specific value that is 5% below the lower boundary of the DSS-CD Armed Region.

Specification	Existing Requirement	Proposed Requirement	Purpose
Completion Time K.1	[4] hours	[4 or 6] hours	The Completion Time of [4 or 6] hours provides the plant operating staff sufficient time for implementation in an orderly manner. A choice of different Completion Times is provided, one of which would be addressed in the plant-specific application. The longer of the two choices of Completions Times addresses the action to a reduce operations to Mode 2.
SR 3.3.1.1.18	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ [30]% and recirculation drive flow is ≤[60]% of rated recirculation drive flow.	Delete	The DSS-CD automatically arms and the SR is unnecessary.
Table 3.3.1.1-1, Function 2.b, Allowable Value, footnote (d)	None	With OPRM Upscale (Function 2.f) inoperable, the modified APRM flow-biased setpoints defined in the COLR may be required to implement the Automated BSP Scram Region in accordance with Action I of this Specification.	The footnote is intended to reflect a possible change in the APRM allowable value due to implementation of the Automated BSP Scram Region described in Section 7.4.
Table 3.3.1.1-1, Function 2.f, Applicable Modes or Other Specified Conditions	≥[25]% RTP	≥[20]% RTP or Mode 1	A choice of different applicability requirements is provided, one of which would be addressed in the plant-specific application. Either one of which represents regions of power-flow operation where anticipated events could lead to thermal-hydraulic oscillations and related neutron flux oscillations. The [20]% RTP is a plant-specific value that is 5% below the lower boundary of the DSS-CD Armed Region.

Specification	Existing Requirement	Proposed Requirement	Purpose
Table 3.3.1.1-1, Function 2.f, Footnote e	See COLR for OPRM period-based detection algorithm (PBDA) setpoint limits.	Following DSS-CD implementation, DSS-CD is not required to be armed while in the DSS-CD Armed Region from the first reactor startup and until the first controlled shutdown that passes completely through the DSS-CD Armed Region. However, DSS-CD shall be OPERABLE and capable of automatically arming consistent with Bases Reference [17] for operation at recirculation drive flow rates above the DSS-CD Armed Region. The DSS-CD Armed Region is defined in Bases Reference [17].	The existing requirement is no longer applicable since the PBDA is no longer credited in the safety analysis. The proposed requirement addresses the limited operability requirements during the initial testing phase following DSS-CD implementation.
Changes in sections other than Specification 3.3.1.1			
5.6.5, Core Operating Limits Report (COLR)	The period-based detection algorithm (PBDA) setpoint for Function 2.f, Oscillation Power Range Monitor (OPRM) Upscale, for Specification 3.3.1.1	The Manual Backup Stability Protection (BSP) Scram Region (Region I), the Manual BSP Controlled Entry Region (Region II), [the modified APRM flow-biased setpoints used in the Automated BSP Scram Region, or the BSP Boundary] for Specification 3.3.1.1.	The existing PBDA is no longer credited in the safety analysis. Specification 3.3.1.1 includes additional core operating limits that must be addressed in the COLR. The choice of the Automated BSP Scram Region or the BSP Boundary, reflects the plant-specific option to implement BSP consistent with Section 7.5.
5.6.9, Reporting Requirements	None	When a report is required by Condition I of LCO 3.3.1.1, "RPS Instrumentation," a report shall be submitted within 90 days of entering the LCO. The report shall outline the preplanned means to provide backup stability protection, the cause of the inoperability, and the plans and schedule for restoring the required instrumentation channels to OPERABLE status.	See Required Action I.2.2.

9.0 REFERENCES

1. NEDO-31960-A, BWR Owners' Group Long-Term Stability Solutions Licensing Methodology, November 1995.

2. NEDO-31960-A, Supplement 1, BWR Owners' Group Long-Term Stability Solutions Licensing Methodology, November 1995.

3. NEDO-32465-A, BWR Owners' Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, August 1996.

4. NEDO-32047-A, ATWS Rule Issues Related to BWR Core Thermal-Hydraulic Stability, June 1995.

5. BWROG-94078, BWR Owners' Group Guidelines for Stability Interim Corrective Action, June 1994.

6. NEDC-32992P-A, ODYSY Application for Stability Licensing Calculations, July 2001.

7. NEDE-32906P-A, Rev. 1, TRACG Application for Anticipated Operational Occurrences (AOO) Transient Analyses, April 2003.

8. NEDE-32176P, Rev. 2, TRACG Model Description, December 1999.

9. NEDE-32177P, Rev. 2, TRACG Qualification, January 2000.

10. NUREG/CR-5249, Quantifying Reactor Safety Margins: Application of Code Scaling, Applicability, and Uncertainty Evaluation Methodology to a Large-Break, Loss-of-Coolant Accident, December 1989.

11. Regulatory Guide 1.157, Best-Estimate Calculations of Emergency Core Cooling System Performance, May 1989.

12. NEDO-30130-A, Steady State Nuclear Methods, April 1985.

13. NEDC-32410P-A, Supplement 1, NUMAC-PRNM Retrofit Plus Option III Stability Trip Function, November 1997.

14. GE Nuclear Energy, "Response to NRC RAIs regarding DSS-CD LTR, NEDC-33075P," MFN 04-001, January 23, 2004.

15. GE Nuclear Energy, "Responses to DSS-CD LTR RAIs," MFN 05-148, December 7, 2005.

16. GE Nuclear Energy, "CPR Margins – DSS-CD LTR (NEDC-33075P, Detect And Suppress Solution – Confirmation Density)," MFN 06-105, April 17, 2006.

17. GE Nuclear Energy, "Response to DSS-CD LTR RAI - Uncertainties," MFN 06-129, May 10, 2006.

18. USNRC, 'Final Safety Evaluation for General Electric Nuclear Energy (GENE) Licensing Topical Report (LTR) NEDC-33075P, Revision 5, "General Electric Boiling Water Reactor Detect and Suppression Solution - Confirmation Density," ML062640346, November 27, 2006.

APPENDIX A: EXAMPLE OF CHANGES TO BWR/4 STANDARD TECHNICAL SPECIFICATIONS - REDLINE/STRIKEOUT VERSION

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR A.2 ---------NOTE-------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. --------------------- Place associated trip system in trip.	12 hours 12 hours
B. ---------NOTE-------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. --------------------- One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour

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ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < [30]% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1 Initiate action to implement the Manual BSP Regions defined in the COLR~~alternate method to detect and suppress thermal hydraulic instability oscillations~~.	~~12 hours~~Immediately
	AND	
	I.2.1 Implement the Automated BSP Scram Region using the modified APRM flow-biased scram setpoints defined in the COLR.	12 hours
	AND	
	I.2.2 Initiate action in accordance with	90 days

CONDITION	REQUIRED ACTION	COMPLETION TIME
	Specification 5.6.9.	
J. Required Action and associated Completion Time of Condition I not met.	J.1 Initiate action to implement the Manual BSP Regions defined in the COLR. AND J.2 Reduce operation to below the BSP Boundary defined in the COLR. AND J.3 Restore required channel to OPERABLE	Immediately 12 hours 120 days
~~J~~K. Required Action and associated Completion Time of Condition ~~I~~ J not met.	~~J~~K.1 [Reduce THERMAL POWER to ~~<~~less than [~~25~~20] % RTP or Be in Mode 2].	[4 or 6] hours

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.1.2	-----NOTE----- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. ----- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP [plus any gain adjustment required by LCO 3.2.4, "Average Power Range Monitor (APRM) Setpoints"] while operating at ≥ 25% RTP.	7 days
SR 3.3.1.1.3	(Not used.)	
SR 3.3.1.1.4	-----NOTE----- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ----- Perform CHANNEL FUNCTIONAL TEST.	7 days

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SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.7	------------------NOTE------------------- Only required to be met during entry into MODE 2 from MODE 1. --- Verify the IRM and APRM channels overlap.	7 days
SR 3.3.1.1.8	Calibrate the local power range monitors.	[1000] MWD/T average core exposure
SR 3.3.1.1.9	Perform CHANNEL FUNCTIONAL TEST.	[92] days
SR 3.3.1.1.10	Calibrate the trip units.	[92] days

(continued)

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.8 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.11	------------------NOTE------------------ For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	[18] months
SR 3.3.1.1.13	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL CALIBRATION.	[18] months
SR 3.3.1.1.14	(Not used.)	
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	[18] months

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SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.16	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ [30]% RTP.	[18] months
SR 3.3.1.1.17	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --- Verify the RPS RESPONSE TIME is within limits.	[18] months on a STAGGERED TEST BASIS
~~SR 3.3.1.1.18~~	~~Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥[30]% and recirculation drive flow is <[60]% of rated recirculation drive flow.~~	~~[18] months~~

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	[3]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [120/125] divisions of full scale
	5[(a)]	[3]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [120/125] divisions of full scale
b. Inop	2	[3]	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[(a)]	[3]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitors					
a. Neutron Flux — High, (Setdown)	2	3[(c)]	G	SR 3.3.1.1.1 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [20]% RTP
b. Simulated Thermal Power — High	1	3[(c)]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [0.58 W + 62]% RTP and ≤ [115.5]% RTP (b) (d)

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) [0.58 W + 62% - 0.58 ΔW]RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) With OPRM Upscale (function 2.f) inoperable, the modified APRM flow-biased setpoints defined by the COLR may be required to implement the Automated BSP Scram Region in accordance with Action I of this Specification.

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
c. Neutron Flux — High	1	3(c)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [120]% RTP
[					]
d. Inop	1,2	3(c)	G	SR 3.3.1.1.11	NA
e. 2-Out-Of-4 Voter	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.11 SR 3.3.1.1.15 SR 3.3.1.1.17	NA
f. OPRM Upscale	[≥ [~~25~~20]% RTP or(e) 1]	3(c)	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13 ~~SR 3.3.1.1.18~~	NA~~(e)~~
3. Reactor Vessel Steam Dome Pressure — High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ [1054] psig
4. Reactor Vessel Water Level — Low, Level 3	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≥ [10] inches
5. Main Steam Isolation Valve — Closure	1	[8]	F	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ [10]% closed
6. Drywell Pressure — High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [1.92] psig

(continued)

(c) Each APRM channel provides inputs to both trip systems.

(e) Following DSS-CD implementation, DSS-CD is not required to be armed while in the DSS-CD Armed Region during the first reactor startup and during the first controlled shutdown that passes completely through the DSS-CD Armed Region. However, DSS-CD shall be OPERABLE and capable of automatically arming consistent with Reference [17] for operation at recirculation drive flow rates above the DSS-CD Armed Region. The DSS-CD Armed Region is defined in Reference [17].

~~(e) See COLR for OPRM period based detection algorithm (PBDA) setpoint limits.~~

Table 3.3.1.1-1 (page 3 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level — High					
a. Resistance Temperature Detector	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
b. Float Switch	1,2	[2]	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
8. Turbine Stop Valve — Closure	≥ [30]% RTP	[4]	E	SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ [10]% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure — Low	≥ [30]% RTP	[2]	E	SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≥ [600] psig
10. Reactor Mode Switch — Shutdown Position	1,2	[2]	G	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
	5(a)	[2]	H	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
11. Manual Scram	1,2	[2]	G	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
	5(a)	[2]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

NO CHANGE TO THIS PAGE

5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

[The individual specifications that address core operating limits must be referenced here.]

[For DSS-CD, the following is required in addition to the normal list of limits:]

~~1. The period based algorithm (PBDA) setpoint for Function 2.f, Oscillation Power Range Monitor (OPRM) Upscale, for Specification 3.3.1.1~~

1. The Manual Backup Stability Protection (BSP) Scram Region (Region I), the Manual BSP Controlled Entry Region (Region II), [the modified APRM flow-biased setpoints used in the Automated BSP Scram Region, or the BSP Boundary] for Specification 3.3.1.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

[Identify the Topical Report(s) by number and title or identify the Staff Safety Evaluation Report for a plant specific methodology by NRC letter and date. The COLR will contain the complete identification for each of the TS referenced topical reports used to prepare the COLR (i.e., report number, title, revision, date, and any supplements.]

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

(continued)

5.6 Reporting Requirements (continued)

5.6.9 OPRM Report

When a report is required by Condition I of LCO 3.3.1.1, "RPS Instrumentation," a report shall be submitted within 90 days of entering the LCO. The report shall outline the preplanned means to provide backup stability protection, the cause of the inoperability, and the plans and schedule for restoring the required instrumentation channels to OPERABLE status.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

BWR/6 STS Note: The wording of the BASES descriptions of APRM Functions is somewhat different from the corresponding Functions for the BWR/4 ISTS to reflect slight differences in the architecture. However, the replacement text will be very similar to that shown in this example mark-up.

Average Power Range Monitor (APRM)

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. Each APRM also includes an Oscillation Power Range Monitor (OPRM) Upscale Function which monitors small groups of LPRM signals to detect thermal-hydraulic instabilities.

The APRM System is divided into four APRM channels and four 2-out-of-4 voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed. A trip from any one unbypassed APRM will result in a "half-trip" in all four of the voter channels, but no trip inputs to either RPS trip system. APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels, which in turn results in two trip inputs into each RPS trip system logic channel (A1, A2, B1, and B2). Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels. Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. In addition, to provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least [20] LPRM inputs, with at least [three] LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. For the OPRM Upscale, Function 2.f, LPRMs are assigned to "cells" of [4] detectors. A minimum of [later] cells, each with a minimum of [2] LPRMs, must be OPERABLE for the OPRM Upscale Function 2.f to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Average Power Range Monitor—Inop

Three of the four APRM channels are required to be OPERABLE for each of the APRM Functions. This Function (Inop) provides assurance that the minimum number of APRM channels are OPERABLE.

For any APRM channel, any time its mode switch is in any position other than "Operate," an APRM module is unplugged, or the automatic self-test system detects a critical fault with the APRM channel, an Inop trip is sent to all four voter channels. Inop trips from two or more unbypassed APRM channels result in a trip output from all four voter channels to their associated trip system.

This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

2.e. 2-Out-Of-4 Voter

The 2-Out-Of-4 Voter Function provides the interface between the APRM Functions, including the OPRM Upscale Function, and the final RPS trip system logic. As such, it is required to be OPERABLE in the MODES where the APRM Functions are required and is necessary to support the safety analysis applicable to each of those Functions. Therefore, the 2-Out-Of-4 Voter Function needs to be OPERABLE in MODES 1 and 2.

All four voter channels are required to be OPERABLE. Each voter channel includes self-diagnostic functions. If any voter channel detects a critical fault in its own processing, a trip is issued from that voter channel to the associated trip system.

The 2-Out-Of-4 Voter Function votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. The voter also includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The voter Function 2.e must be declared inoperable if any of its functionality is inoperable. However, due to the independent voting of APRM trips, and the redundancy of outputs, there may be conditions where the voter Function 2.e is inoperable, but trip capability for one or more of the other APRM Functions through that voter is still maintained. This may be considered when determining the condition of other APRM Functions resulting from partial inoperability of the Voter Function 2.e.

There is no Allowable Value for this Function.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.f. Oscillation Power Range Monitor (OPRM) Upscale

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

Reference [17] describes the Detect and Suppress - Confirmation Density (DSS-CD) long-term stability solution and the licensing basis Confirmation Density Algorithm (CDA). ~~and~~ Reference [17] also describes the DSS-CD Armed Region and the~~References [12], [13] and [14] describe~~ three additional algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (PBDA), the amplitude based algorithm (ABA), and the growth rate algorithm (GRA). All ~~three~~four algorithms are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the ~~period based detection algorithm~~CDA. The remaining three algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY ~~for Technical Specification purposes~~ is based only on the ~~period based detection algorithm~~CDA.

The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms.

DSS-CD operability requires at least 8 responsive OPRM cells per channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is [at ~~≥~~greater than or equal to ~~[25]%~~ RTP below the lower boundary of the Armed Region, which is 20% RTP or in Mode 1], encompassing the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. ~~Within this region, t~~The automatic trip is enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is greater than or equal to the ~~≥[30]%~~ RTP corresponding to the plant-specific MCPR monitoring threshold and reactor ~~core flow, as indicated by~~ recirculation drive flow, is ~~<~~ less than [~~60~~75 for MELLLA+ or 70 for MELLLA]% of rated flow~~, the operating region where actual thermal hydraulic oscillations may occur~~. ~~The lower bound, [25]% RTP, is chosen to provide margin in the unlikely event of loss of feedwater heating while the plant is operating below the [30]% automatic OPRM Upscale trip enable point. Loss of feedwater heating is the only identified event that could cause reactor power to increase into the region of concern without operator action.~~ Note e allows for entry into the DSS-CD Armed Region without automatic arming of DSS-CD prior to completely passing though the DSS-CD Armed Region during both a single startup and a single shutdown following DSS-CD implementation. Note e reflects the need for plant data collection in order to test the DSS-CD equipment. Testing the DSS-CD equipment ensures its proper operation and prevents spurious reactor trips. Entry into the DSS-CD Armed Region without automatic arming of DSS-CD during this initial testing phase also allows for changes in plant operations to address maintenance or other operational needs. However, during this initial testing period, DSS-CD operability and capability to automatically arm shall be maintained at recirculation drive flow rates above the DSS-CD Armed Region.

An OPRM Upscale trip is issued from an ~~APRM~~ OPRM channel when the ~~period based detection~~confirmation density algorithm in that channel detects oscillatory changes in the neutron flux, indicated by period confirmations and amplitude exceeding specified setpoints for a specified number of OPRM cells in the channel. ~~the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip.~~ An OPRM Upscale trip is also issued from the channel if ~~either~~ any of the defense-in-depth algorithms (PBDA, ABA, GRA) ~~the growth rate or amplitude based algorithms detect growing oscillatory changes in the neutron flux~~exceed ~~the~~its trip condition for one or more cells in that channel.

Three of the four channels are required to be operable. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the MCPR SL is exceeded. There is no allowable value for this function.

ACTIONS

A.1 and A.2A.1

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 9 and [11]) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

As noted, Action A.2 is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, Required Action A.1 must be satisfied, and is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and entry into Condition C, as well as entry into Condition A for each channel.

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ACTIONS

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in References 9 or [11] for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in References 9 or [11], which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

NO CHANGE TO THIS PAGE

ACTIONS

B.1 and B.2 (continued)

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram [or RPT]), Condition D must be entered and its Required Action taken.

As noted, Condition B is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-out-of-4 voter and other non-APRM channels for which Condition B applies. For an inoperable APRM channel, Required Action A.1 must be satisfied, and is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of a Function in more than one required APRM channel results in loss of trip capability for that Function and entry into Condition C, as well as entry into Condition A for each channel. Because Conditions A and C provide Required Actions that are appropriate for the inoperability of APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f, and these functions are not associated with specific trip systems as are the APRM 2-out-of-4 voter and other non-APRM channels, Condition B does not apply.

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ACTIONS

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 8 (Turbine Stop Valve--Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

E.1, F.1, G.1, and J.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Actions E.1 and J.1 are consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

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ACTIONS

I.1

If OPRM Upscale trip capability is not maintained, Condition I exists and Backup Stability Protection (BSP) is required. ~~Reference [11] justified use of alternate methods to detect and suppress oscillations for a limited period of time.~~ The ~~m~~Manual BSP Regions are described in Reference [17]. The ~~alternatem~~Manual BSP Regions ~~methods are~~ are procedurally established consistent with the guidelines identified in Reference [~~16~~17] and require~~ing~~ specified manual operator actions~~action to scram the plant~~ if certain predefined ~~events~~ operational conditions occur.

The Completion Time of immediate is based on the importance of ~~The 12 hour allowed action time is based on engineering judgment to allow orderly transition to the alternate methods while~~ limiting the period of time during which no automatic or alternate detect and suppress trip capability is ~~formally~~ in place. ~~Based on the small probability of an instability event occurring at all, the 12 hours is judged to be reasonable.~~

I.2.1 and I.2.2

Actions I.2.1 and I.2.2 are both required to be taken in conjunction with Action I.1 if OPRM Upscale trip capability is not maintained. As described in Section 7.4 of Reference [17], the Automated BSP Scram Region is designed to avoid reactor instability by automatically preventing entry into the region of the power and flow-operating map that is susceptible to reactor instability. The reactor trip would be initiated by the modified APRM flow-biased scram setpoints for flow reduction events that would have terminated in the Manual BSP Region I. The Automated BSP Scram Region ensures an early scram and SLMCPR protection.

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, and based on the importance of restoring an automatic reactor trip for thermal hydraulic instability events.

Backup Stability Protection is intended as a temporary means to protection against thermal-hydraulic instability events. The reporting requirements of Specification 5.6.9 document the corrective actions and schedule to restore the required channels to an OPERABLE status. The Completion Time of 90 days is adequate to allow time to evaluate the cause of the inoperability and to determine the appropriate corrective actions and schedule to restore the required channels to OPERABLE status.

J.1

If the Required Actions I are not completed within the associated Completion Times, then Action J is required. The Bases for the Manual BSP Regions and associated Completion Time is addressed in the Bases for I.1. The Manual BSP Regions are required in conjunction with the BSP Boundary.

J.2

The BSP Boundary, as described in Section 7.3 of Reference [17], defines an operating domain where potential instability events can be effectively addressed by the specified BSP manual operator actions. The BSP Boundary is constructed such that the immediate final statepoint for a flow reduction event initiated from this boundary and terminated at the core natural circulation line (NCL) would not exceed the Manual BSP Region I stability criterion. Potential instabilities would develop slowly as a result of the feedwater temperature transient (Reference [17].

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, to reach the specific condition from full power conditions in an orderly manner and without challenging plant system.

J.3

Backup Stability Protection (BSP) is a temporary means for protection against thermal-hydraulic instability events. An extended period of inoperability without automatic trip capability is not justified. Consequently, the required channels are required to be restored to OPERABLE status within 120 days.

~~The alternate method to detect and suppress oscillations implemented in accordance with I.1 was evaluated (Reference [11]) based on use up to 120 days only. The evaluation, b~~Based on engineering judgment, ~~concluded that~~ the likelihood of an instability event that could not be adequately handled by the ~~alternate methods~~use of the BSP Regions (See Action J.1) and the BSP Boundary (See J.2) during ~~this~~ a 120--day period ~~was~~ is negligibly small. The 120-day period is intended ~~to be an outside limit~~ to allow for the case where limited design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. This action is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to normally be accomplished within the completion times allowed for Actions for Conditions A and B.

K.1

If the required channels are not restored to OPERABLE status and the Required Actions of J are not met within the associated Completion Times, then the plant must be placed in an operating condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least [20% RTP or Mode 2] within [4 or 6] hours. The allowed Completion Time is reasonable, based on operating experience, to reach the specified operating power level from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoints," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of calculated MFLPD. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (Continued)

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The [1000] MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.10

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be

readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 9.

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.8 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.11

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. For the APRM Functions, this test supplements the automatic self-test functions that operate continuously in the APRM and voter channels. The APRM CHANNEL FUNCTIONAL TEST covers the APRM channels (including recirculation flow processing -- applicable to Function 2.b only), the 2-out-of-4 voter channels, and the interface connections into the RPS trip systems from the voter channels. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 184 day Frequency of SR 3.3.1.1.11 is based on the reliability analysis of Reference [11]. (NOTE: The actual voting logic of the 2-Out-Of-4 Voter Function is tested as part of SR 3.3.1.1.15.)

A Note is provided for Function 2.a that requires this SR to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM Function cannot be performed in MODE 1 without utilizing jumpers or lifted leads. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2.

NOTE: The addition of "for Function 2.a" in the above paragraph repeats what the note actually says for clarity. It is not related to the OPRM addition, and is optional for APRM changes in that it does not change the actual meaning.

SR 3.3.1.1.13

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. For the APRM Simulated Thermal Power - High Function, this SR also includes calibrating the associated recirculation loop flow channel.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.13 (continued)

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the [1000] MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). A second Note is provided that requires the IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

The Frequency of SR 3.3.1.1.13 is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.14

(Not used.)

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

The LOGIC SYSTEM FUNCTIONAL TEST for APRM Function 2.e simulates APRM and OPRM trip conditions at the 2-out-of-4 voter channel inputs to check all combinations of two tripped inputs to the 2-out-of-4 logic in the voter channels and APRM related redundant RPS relays.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ 30% RTP to ensure that the calibration remains valid.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.17

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference [ ].

RPS RESPONSE TIME for the APRM 2-Out-Of-4 Voter Function (2.e) includes the output relays of the voter and the associated RPS relays and contactors. (The digital portion of the APRM and 2-out-of-4 voter channels are excluded from RPS RESPONSE TIME testing because self-testing and calibration checks the time base of the digital electronics. Confirmation of the time base is adequate to assure required response times are met. Neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.)

NOTE: Replacement of Reference "10" with "[ ]" is to avoid confusion. The NUREG includes a "10", but no actual Reference by that number. The reference should be to the utility's document containing response time testing requirements -- not identified in this sample mark-up.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.17 (continued)

RPS RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The 18 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

~~SR 3.3.1.1.18~~

~~This SR ensures that scrams initiated from OPRM Upscale Function (Function 2.f) will not be inadvertently bypassed when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is ≥[30]% RTP and core flow, as indicated by recirculation drive flow, is <[60]% rated core flow. This normally involves confirming the bypass setpoints. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. The actual surveillance ensures that the OPRM Upscale Function is enabled (not bypassed) for the correct values of APRM Simulated Thermal Power and recirculation drive flow. Other surveillances ensure that the APRM Simulated Thermal Power and recirculation flow properly correlate with THERMAL POWER and core flow, respectively.~~

~~If any bypass setpoint is nonconservative (i.e., the OPRM Upscale Function is bypassed when APRM Simulated Thermal Power ≥[30]% and recirculation drive flow <[60]% rated), then the affected channel is considered inoperable for the OPRM Upscale Function. Alternatively, the bypass setpoint may be adjusted to place the channel in a conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.~~

~~The Frequency of [18] months is based on engineering judgment and reliability of the components.~~

BASES

REFERENCES

1. FSAR, Figure [ ].

2. FSAR, Section [15.1.2].

3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.

4. FSAR, Section [5.2.2].

5. FSAR, Section [15.1.38].

6. FSAR, Section [6.3.3].

7. FSAR, Chapter [15].

8. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.

9. NEDO-30851-P-A , "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

10. FSAR, Table [7.2-2].

11. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function", October 1995. ~~[March 1995].~~

12. ~~NEDO-31960-A, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995~~Not used.

13. ~~NEDO-31960-A, Supplement 1, "BWR Owners' Group Long-Term Stability Solutions Licensing Methodology," November 1995~~Not used.

14. ~~NEDO-32465-A, "BWR Owners' Group Long-Term Stability Detect and Suppress Solutions Licensing Basis Methodology And Reload Applications," [March 1996]~~Not used.

15. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function", [August 1996].

16. ~~Letter, LA England (BWROG) to MJ Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action", June 6, 1994~~Not used.

17. NEDC-33075P, Revision 5, "General Electric Boiling Water Reactor Detect and Suppress Solution - Confirmation Density," November 2005.

APPENDIX B: EXAMPLE OF CHANGES TO BWR/4 STANDARD TECHNICAL SPECIFICATIONS – REVISION BAR VERSION

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

-----NOTE-----
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR A.2 ---------NOTE-------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. --------------------- Place associated trip system in trip.	12 hours 12 hours
B. ---------NOTE-------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. --------------------- One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	6 hours 6 hours
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour

(continued)

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ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < [30]% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1	Initiate action to implement the Manual BSP Regions defined in the COLR.	Immediately
	<u>AND</u>		
	I.2.1	Implement the Automated BSP Scram Region using the modified APRM flow-biased scram setpoints defined in the COLR.	12 hours
	<u>AND</u>		
	I.2.2	Initiate action in accordance with Specification 5.6.9.	90 days

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. Required Action and associated Completion Time of Condition I not met.	J.1 Initiate action to implement the Manual BSP Regions defined in the COLR.	Immediately
	AND	
	J.2 Reduce operation to below the BSP Boundary defined in the COLR.	12 hours
	AND	
	J.3 Restore required channel to OPERABLE	120 days
K. Required Action and associated Completion Time of Condition J not met.	K.1 [Reduce THERMAL POWER to less than [20]% RTP or Be in Mode 2].	[4 or 6] hours

SURVEILLANCE REQUIREMENTS

------------------------------NOTES------------------------------

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.1.2	------------------NOTE------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP [plus any gain adjustment required by LCO 3.2.4, "Average Power Range Monitor (APRM) Setpoints"] while operating at ≥ 25% RTP.	7 days
SR 3.3.1.1.3	(Not used.)	
SR 3.3.1.1.4	------------------NOTE------------------ Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	7 days

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to withdrawing SRMs from the fully inserted position
SR 3.3.1.1.7	------------------NOTE------------------- Only required to be met during entry into MODE 2 from MODE 1. --- Verify the IRM and APRM channels overlap.	7 days
SR 3.3.1.1.8	Calibrate the local power range monitors.	[1000] MWD/T average core exposure
SR 3.3.1.1.9	Perform CHANNEL FUNCTIONAL TEST.	[92] days
SR 3.3.1.1.10	Calibrate the trip units.	[92] days

(continued)

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.8 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.11	------------------NOTE------------------ For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.1.1.12	Perform CHANNEL FUNCTIONAL TEST.	[18] months
SR 3.3.1.1.13	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL CALIBRATION.	[18] months
SR 3.3.1.1.14	(Not used.)	
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	[18] months

(continued)

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SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.16	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ [30]% RTP.	[18] months
SR 3.3.1.1.17	------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. --- Verify the RPS RESPONSE TIME is within limits.	[18] months on a STAGGERED TEST BASIS

Table 3.3.1.1-1 (page 1 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	[3]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [120/125] divisions of full scale
	5(a)	[3]	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [120/125] divisions of full scale
b. Inop	2	[3]	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5(a)	[3]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitors					
a. Neutron Flux — High, (Setdown)	2	3(c)	G	SR 3.3.1.1.1 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [20]% RTP
b. Simulated Thermal Power — High	1	3(c)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [0.58 W + 62]% RTP and ≤ [115.5]% RTP (b) (d)

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) [0.58 W + 62% - 0.58 ΔW]RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides inputs to both trip systems.

(d) With OPRM Upscale (function 2.f) inoperable, the modified APRM flow-biased setpoints defined by the COLR may be required to implement the Automated BSP Scram Region in accordance with Action I of this Specification.

Table 3.3.1.1-1 (page 2 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Average Power Range Monitors (continued)					
c. Neutron Flux — High	1	3(c)	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	≤ [120]% RTP
[					]
d. Inop	1,2	3(c)	G	SR 3.3.1.1.11	NA
e. 2-Out-Of-4 Voter	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.11 SR 3.3.1.1.15 SR 3.3.1.1.17	NA
f. OPRM Upscale	[≥ [20]% RTP or 1](e)	3(c)	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.11 SR 3.3.1.1.13	NA
3. Reactor Vessel Steam Dome Pressure — High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ [1054] psig
4. Reactor Vessel Water Level — Low, Level 3	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≥ [10] inches
5. Main Steam Isolation Valve — Closure	1	[8]	F	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ [10]% closed
6. Drywell Pressure — High	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [1.92] psig

(continued)

(c) Each APRM channel provides inputs to both trip systems.
(e) Following DSS-CD implementation, DSS-CD is not required to be armed while in the DSS-CD Armed Region during the first reactor startup and during the first controlled shutdown that passes completely through the DSS-CD Armed Region. However, DSS-CD shall be OPERABLE and capable of automatically arming consistent with Reference [17] for operation at recirculation drive flow rates above the DSS-CD Armed Region. The DSS-CD Armed Region is defined in Reference [17].

Table 3.3.1.1-1 (page 3 of 3)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level — High					
a. Resistance Temperature Detector	1,2	[2]	G	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.1 SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
b. Float Switch	1,2	[2]	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
	5(a)	[2]	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ [57.15] gallons
8. Turbine Stop Valve — Closure	≥ [30]% RTP	[4]	E	SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ [10]% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure — Low	≥ [30]% RTP	[2]	E	SR 3.3.1.1.9 [SR 3.3.1.1.10] SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≥ [600] psig
10. Reactor Mode Switch — Shutdown Position	1,2	[2]	G	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
	5(a)	[2]	H	SR 3.3.1.1.12 SR 3.3.1.1.15	NA
11. Manual Scram	1,2	[2]	G	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
	5(a)	[2]	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

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5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

[The individual specifications that address core operating limits must be referenced here.]

[For DSS-CD, the following is required in addition to the normal list of limits:]

1. The Manual Backup Stability Protection (BSP) Scram Region (Region I), the Manual BSP Controlled Entry Region (Region II), [the modified APRM flow-biased setpoints used in the Automated BSP Scram Region, or the BSP Boundary] for Specification 3.3.1.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

[Identify the Topical Report(s) by number and title or identify the Staff Safety Evaluation Report for a plant specific methodology by NRC letter and date. The COLR will contain the complete identification for each of the TS referenced topical reports used to prepare the COLR (i.e., report number, title, revision, date, and any supplements.]

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

(continued)

5.6.9 OPRM Report

When a report is required by Condition I of LCO 3.3.1.1, "RPS Instrumentation," a report shall be submitted within 90 days of entering the LCO. The report shall outline the preplanned means to provide backup stability protection, the cause of the inoperability, and the plans and schedule for restoring the required instrumentation channels to OPERABLE status.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

BWR/6 STS Note: The wording of the BASES descriptions of APRM Functions is somewhat different from the corresponding Functions for the BWR/4 ISTS to reflect slight differences in the architecture. However, the replacement text will be very similar to that shown in this example mark-up.

Average Power Range Monitor (APRM)

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. Each APRM also includes an Oscillation Power Range Monitor (OPRM) Upscale Function which monitors small groups of LPRM signals to detect thermal-hydraulic instabilities.

The APRM System is divided into four APRM channels and four 2-out-of-4 voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each, with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed. A trip from any one unbypassed APRM will result in a "half-trip" in all four of the voter channels, but no trip inputs to either RPS trip system. APRM trip Functions 2.a, 2.b, 2.c, and 2.d are voted independently from OPRM Upscale Function 2.f. Therefore, any Function 2.a, 2.b, 2.c, or 2.d trip from any two unbypassed APRM channels will result in a full trip in each of the four voter channels, which in turn results in two trip inputs into each RPS trip system logic channel (A1, A2, B1, and B2). Similarly, a Function 2.f trip from any two unbypassed APRM channels will result in a full trip from each of the four voter channels. Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. In addition, to provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b, and 2.c, at least [20] LPRM inputs, with at least [three] LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel. For the OPRM Upscale, Function 2.f, LPRMs are assigned to "cells" of [4] detectors. A minimum of [later] cells, each with a minimum of [2] LPRMs, must be OPERABLE for the OPRM Upscale Function 2.f to be OPERABLE.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.d. Average Power Range Monitor—Inop

Three of the four APRM channels are required to be OPERABLE for each of the APRM Functions. This Function (Inop) provides assurance that the minimum number of APRM channels are OPERABLE.

For any APRM channel, any time its mode switch is in any position other than "Operate," an APRM module is unplugged, or the automatic self-test system detects a critical fault with the APRM channel, an Inop trip is sent to all four voter channels. Inop trips from two or more unbypassed APRM channels result in a trip output from all four voter channels to their associated trip system.

This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

2.e. 2-Out-Of-4 Voter

The 2-Out-Of-4 Voter Function provides the interface between the APRM Functions, including the OPRM Upscale Function, and the final RPS trip system logic. As such, it is required to be OPERABLE in the MODES where the APRM Functions are required and is necessary to support the safety analysis applicable to each of those Functions. Therefore, the 2-Out-Of-4 Voter Function needs to be OPERABLE in MODES 1 and 2.

All four voter channels are required to be OPERABLE. Each voter channel includes self-diagnostic functions. If any voter channel detects a critical fault in its own processing, a trip is issued from that voter channel to the associated trip system.

The 2-Out-Of-4 Voter Function votes APRM Functions 2.a, 2.b, 2.c, and 2.d independently of Function 2.f. The voter also includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The voter Function 2.e must be declared inoperable if any of its functionality is inoperable. However, due to the independent voting of APRM trips, and the redundancy of outputs, there may be conditions where the voter Function 2.e is inoperable, but trip capability for one or more of the other APRM Functions through that voter is still maintained. This may be considered when determining the condition of other APRM Functions resulting from partial inoperability of the Voter Function 2.e.

There is no Allowable Value for this Function.

NO CHANGE TO THIS PAGE

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.f. Oscillation Power Range Monitor (OPRM) Upscale

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

Reference [17] describes the Detect and Suppress - Confirmation Density (DSS-CD) long-term stability solution and the licensing basis Confirmation Density Algorithm (CDA). Reference [17] also describes the DSS-CD Armed Region and the three additional algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (PBDA), the amplitude based algorithm (ABA), and the growth rate algorithm (GRA). All four algorithms are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the CDA. The remaining three algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY is based only on the CDA.

The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms.

DSS-CD operability requires at least 8 responsive OPRM cells per channel.

The OPRM Upscale Function is required to be OPERABLE when the plant is [at greater than or equal to 5% RTP below the lower boundary of the Armed Region, which is 20% RTP or in Mode 1], encompassing the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. The automatic trip is enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is greater than or equal to the RTP corresponding to the plant-specific MCPR monitoring threshold and reactor recirculation drive flow, is less than [75 for MELLLA+ or 70 for MELLLA]% of rated flow. Note e allows for entry into the DSS-CD Armed Region without automatic arming of DSS-CD prior to completely passing though the DSS-CD Armed Region during both a single startup and a single shutdown following DSS-CD implementation. Note e reflects the need for plant data collection in order to test the DSS-CD equipment. Testing the DSS-CD equipment ensures its proper operation and prevents spurious reactor trips. Entry into the DSS-CD Armed Region without automatic arming of DSS-CD during this initial testing phase also allows for changes in plant operations to address maintenance or other operational needs. However, during this initial testing period, DSS-CD operability and capability to automatically arm shall be maintained at recirculation drive flow rates above the DSS-CD Armed Region.

An OPRM Upscale trip is issued from an OPRM channel when the confirmation density algorithm in that channel detects oscillatory changes in the neutron flux, indicated by period confirmations and amplitude exceeding specified setpoints for a specified number of OPRM cells in the channel. An OPRM Upscale trip is also issued from the channel if any of the defense-in-depth algorithms (PBDA, ABA, GRA) exceed its trip condition for one or more cells in that channel.

Three of the four channels are required to be operable. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the MCPR SL is exceeded. There is no allowable value for this function.

ACTIONS

A.1 and A.2A.1

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 9 and [11]) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

As noted, Action A.2 is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, Required Action A.1 must be satisfied, and is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and entry into Condition C, as well as entry into Condition A for each channel.

NO CHANGE TO THIS PAGE

ACTIONS

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in References 9 or [11] for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in References 9 or [11], which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

NO CHANGE TO THIS PAGE

ACTIONS

B.1 and B.2 (continued)

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram [or RPT]), Condition D must be entered and its Required Action taken.

As noted, Condition B is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-out-of-4 voter and other non-APRM channels for which Condition B applies. For an inoperable APRM channel, Required Action A.1 must be satisfied, and is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of a Function in more than one required APRM channel results in loss of trip capability for that Function and entry into Condition C, as well as entry into Condition A for each channel. Because Conditions A and C provide Required Actions that are appropriate for the inoperability of APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f, and these functions are not associated with specific trip systems as are the APRM 2-out-of-4 voter and other non-APRM channels, Condition B does not apply.

NO CHANGE TO THIS PAGE

ACTIONS

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve--Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip).

For Function 8 (Turbine Stop Valve--Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip).

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

E.1, F.1, G.1, and J.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Actions E.1 and J.1 are consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

NO CHANGE TO THIS PAGE

ACTIONS

I.1

If OPRM Upscale trip capability is not maintained, Condition I exists and Backup Stability Protection (BSP) is required. The Manual BSP Regions are described in Reference [17]. The Manual BSP Regions are procedurally established consistent with the guidelines identified in Reference [17] and require specified manual operator actions if certain predefined operational conditions occur.

The Completion Time of immediate is based on the importance of limiting the period of time during which no automatic or alternate detect and suppress trip capability is in place.

I.2.1 and I.2.2

Actions I.2.1 and I.2.2 are both required to be taken in conjunction with Action I.1 if OPRM Upscale trip capability is not maintained. As described in Section 7.4 of Reference [17], the Automated BSP Scram Region is designed to avoid reactor instability by automatically preventing entry into the region of the power and flow-operating map that is susceptible to reactor instability. The reactor trip would be initiated by the modified APRM flow-biased scram setpoints for flow reduction events that would have terminated in the Manual BSP Region I. The Automated BSP Scram Region ensures an early scram and SLMCPR protection.

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, and based on the importance of restoring an automatic reactor trip for thermal hydraulic instability events.

Backup Stability Protection is intended as a temporary means to protection against thermal-hydraulic instability events. The reporting requirements of Specification 5.6.9 document the corrective actions and schedule to restore the required channels to an OPERABLE status. The Completion Time of 90 days is adequate to allow time to evaluate the cause of the inoperability and to determine the appropriate corrective actions and schedule to restore the required channels to OPERABLE status.

J.1

If the Required Actions I are not completed within the associated Completion Times, then Action J is required. The Bases for the Manual BSP Regions and associated Completion Time is addressed in the Bases for I.1. The Manual BSP Regions are required in conjunction with the BSP Boundary.

J.2

The BSP Boundary, as described in Section 7.3 of Reference [17], defines an operating domain where potential instability events can be effectively addressed by the specified BSP manual operator actions. The BSP Boundary is constructed such that the immediate final statepoint for a flow reduction event initiated from this boundary and terminated at the core natural circulation line (NCL) would not exceed the Manual BSP Region I stability criterion. Potential instabilities would develop slowly as a result of the feedwater temperature transient (Reference [17].

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, to reach the specific condition from full power conditions in an orderly manner and without challenging plant system.

J.3

Backup Stability Protection (BSP) is a temporary means for protection against thermal-hydraulic instability events. An extended period of inoperability without automatic trip capability is not justified. Consequently, the required channels are required to be restored to OPERABLE status within 120 days.

Based on engineering judgment, the likelihood of an instability event that could not be adequately handled by the use of the BSP Regions (See Action J.1) and the BSP Boundary (See J.2) during a 120-day period is negligibly small. The 120-day period is intended to allow for the case where limited design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. This action is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to normally be accomplished within the completion times allowed for Actions for Conditions A and B.

K.1

If the required channels are not restored to OPERABLE status and the Required Actions of J are not met within the associated Completion Times, then the plant must be placed in an operating condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least [20% RTP or Mode 2] within [4 or 6] hours. The allowed Completion Time is reasonable, based on operating experience, to reach the specified operating power level from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. LCO 3.2.4, "Average Power Range Monitor (APRM) Gain and Setpoints," allows the APRMs to be reading greater than actual THERMAL POWER to compensate for localized power peaking. When this adjustment is made, the requirement for the APRMs to indicate within 2% RTP of calculated power is modified to require the APRMs to indicate within 2% RTP of calculated MFLPD. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.8.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.6 and SR 3.3.1.1.7 (Continued)

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The [1000] MWD/T Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.9 and SR 3.3.1.1.12

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.10

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be

readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 9.

NOTE: The addition of "[ ]" around the 1000 MWD/T in SR 3.3.1.1.8 above is to recognize that some plants have justified 2000 MWD/T. It is not related to the OPRM addition and does not affect the actual APRM change required by a plant.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.11

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. For the APRM Functions, this test supplements the automatic self-test functions that operate continuously in the APRM and voter channels. The APRM CHANNEL FUNCTIONAL TEST covers the APRM channels (including recirculation flow processing -- applicable to Function 2.b only), the 2-out-of-4 voter channels, and the interface connections into the RPS trip systems from the voter channels. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 184 day Frequency of SR 3.3.1.1.11 is based on the reliability analysis of Reference [11]. (NOTE: The actual voting logic of the 2-Out-Of-4 Voter Function is tested as part of SR 3.3.1.1.15.)

A Note is provided for Function 2.a that requires this SR to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM Function cannot be performed in MODE 1 without utilizing jumpers or lifted leads. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2.

NOTE: The addition of "for Function 2.a" in the above paragraph repeats what the note actually says for clarity. It is not related to the OPRM addition, and is optional for APRM changes in that it does not change the actual meaning.

SR 3.3.1.1.13

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. For the APRM Simulated Thermal Power - High Function, this SR also includes calibrating the associated recirculation loop flow channel.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.13 (continued)

Note 1 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the [1000] MWD/T LPRM calibration against the TIPs (SR 3.3.1.1.8). A second Note is provided that requires the IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

The Frequency of SR 3.3.1.1.13 is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.14

(Not used.)

SR 3.3.1.1.15

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods (LCO 3.1.3), and SDV vent and drain valves (LCO 3.1.8), overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

The LOGIC SYSTEM FUNCTIONAL TEST for APRM Function 2.e simulates APRM and OPRM trip conditions at the 2-out-of-4 voter channel inputs to check all combinations of two tripped inputs to the 2-out-of-4 logic in the voter channels and APRM related redundant RPS relays.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ 30% RTP to ensure that the calibration remains valid.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.17

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all components are tested. The RPS RESPONSE TIME acceptance criteria are included in Reference [ ].

RPS RESPONSE TIME for the APRM 2-Out-Of-4 Voter Function (2.e) includes the output relays of the voter and the associated RPS relays and contactors. (The digital portion of the APRM and 2-out-of-4 voter channels are excluded from RPS RESPONSE TIME testing because self-testing and calibration checks the time base of the digital electronics. Confirmation of the time base is adequate to assure required response times are met. Neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.)

NOTE: Replacement of Reference "10" with "[ ]" is to avoid confusion. The NUREG includes a "10", but no actual Reference by that number. The reference should be to the utility's document containing response time testing requirements -- not identified in this sample mark-up.

NO CHANGE TO THIS PAGE

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.17 (continued)

RPS RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Note 2 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The 18 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

BASES

REFERENCES

1. FSAR, Figure [ ].

2. FSAR, Section [15.1.2].

3. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.

4. FSAR, Section [5.2.2].

5. FSAR, Section [15.1.38].

6. FSAR, Section [6.3.3].

7. FSAR, Chapter [15].

8. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.

9. NEDO-30851-P-A , "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

10. FSAR, Table [7.2-2].

11. NEDC-32410P-A, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function", October 1995.

12. Not used.

13. Not used.

14. Not used.

15. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function", [August 1996].

16. Not used.

17. NEDC-33075P, Revision 5, "General Electric Boiling Water Reactor Detect and Suppress Solution - Confirmation Density," November 2005.

APPENDIX C: GEH RESPONSES TO NRC RAIs

RAI Table of Contents

RAI Table of Contents (con't)

Generic Licensing Basis – RAI 1

The basic approach for the detect and suppress solution - confirmation density (DSS-CD) licensing basis is generic in nature. No specific reload confirmations are required. This generic confirmation of DSS-CD has been performed in NEDC-33075P, Rev 2, with TRACG, which is not a NRC-approved code. While TRACG has been used for the generation of the DIVOM curve for other detect and suppress solutions, it is not typically used to demonstrate compliance with safety limits. Provide the rationale and justification for using a non NRC-approved code as the basis for the generic DSS-CD licensing.

GE Response

GE is committed to provide a separate Licensing Topical Report documenting the qualification of TRACG for DSS-CD stability application, as stated in letter, MFN 03-116, "NRC Review of TRACG Code (TAC No. MB5705)," dated October 13, 2003.

Generic Licensing Basis – RAI 2

The GEXL correlation is essentially a steady-state correlation based on channel-integral parameters. Provide the basis for using the GEXL correlation during power oscillation transients.

GE Response

The GEXL correlation is developed from steady state critical power data. The test data for a given fuel design cover a range of axial and local power distributions, mass flow, inlet subcooling and pressure. The mass flow range is 0.1 to approximately 1.5 Mlb/ft^2-hr. For each product line the database typically include in the order of 600-1000 critical power data points. The data range is chosen to cover normal operation as well as expected range during operational transients.

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3.6 Critical Power

Every General Electric fuel design is tested in the ATLAS thermal-hydraulic test facility. ATLAS is a single bundle test loop capable of simulating BWR operating conditions. The ATLAS test bundles are electrically heated, full-scale replicas of the actual fuel bundles. Extensive testing in ATLAS has established the steady-state critical power database for the GEXL correlation, which is employed in TRACG to predict the onset of boiling transition (BT). In addition, transient critical power tests are performed in the ATLAS facility. This section contains comparisons of transient TRACG-GEXL predictions of experimental data.

3.6.1 Flow Oscillation Tests

ATLAS flow oscillation tests were recently introduced as a standard part of the transient test program. These tests are intended to demonstrate that the GEXL correlation will perform in a transient application, under conditions where density wave oscillations are likely to occur.

3.6.1.1 Test Description

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Table 3.5-2*

ATLAS Test Faciltiy Measurement Uncertainties

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* The response to this RAI was originally provided in GE letter, MFN 04-001, dated January 23, 2004 [Ref 14]. Subsequently in GE letter, MFN 05-148, dated December 7, 2005 [Ref. 15], GE committed to add Table 3.5-2 to this RAI response as part of the '-A' version of the LTR.

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Generic Licensing Basis – RAI 3

Provide a list of the decay ratio values at or around the moment of scram for the cases in the Confirmation Event Matrix (Section 4 of LTR). Based on these values, are these calculations reasonably limiting?

GE Response

The cases in the confirmation event matrix were selected because they represent reasonably limiting events for anticipated core designs. The initial conditions (i.e., power, core flow, exposure, etc.) were selected to maximize the oscillations following [[ ]] thereby demonstrate the effectiveness of the DSS-CD solution.

The following table provides the approximate growth rate for the six cases in the Confirmation Event Matrix near the moment of scram and near the time at which the hot channel CPR would violate the SLMCPR if no scram were simulated.

The results show that all cases are inherently unstable immediately following [[ ]] at the time of scram. In general, the growth rate tends to increase prior to the time of SLMCPR violation.

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		]]

[[ ]]

The table shows that the range of growth rates covered by the selected reasonably limiting event cases addresses the full range of growth rates up to and including the growth rate algorithm (GRA) setpoint of 1.3.

Generic Licensing Basis – RAI 4

The DSS-CD methodology has only been demonstrated for GE fuels (GE 14 and earlier). Provide the analysis methodology for plant-specific calculations if the plant falls outside the licensed envelope (e.g., different vendor's fuel or future fuel design beyond GE14) and demonstrate that Tables 6-1 and 6-2 are still applicable for fuel design other than GE fuel production line stated in Table 6-1. Specifically, address the three following scenarios:

a) A non-GE fuel plant that is going to reload GE fuel
b) A GE plant that is going to reload non-GE fuel
c) A non-GE plant that request a GE analysis for DSS-CD

GE Response

The DSS-CD plant specific application process is described in Section 6.0 of the DSS-CD LTR. This section also describes the process necessary to support extensions to the applicability envelope. If an application falls outside the parameter ranges provided in Table 6-1, additional justification to assure SLMCPR protection is required. For the purpose of applicability extension, the analysis is performed in accordance with the DSS-CD applicability extension evaluation procedure provided in Table 6-2. [[

]] based on the results documented in Section 4.0 of the LTR. [[

]] For DSS-CD evaluation of future GE fuel designs or other vendor's fuel design, the simulation case is performed with the applicable fuel and core design assumptions. [[

]]

Table 6-3 of the DSS-CD LTR Rev 3 provides a comprehensive list of possible fuel design transition scenarios among approved and unapproved GE and non-GE fuel designs for DSS-CD applications. The table specifies [[

]] per the procedure of Table 6-2.

Generic Licensing Basis - RAI 5

Provide in detail, the necessary software and hardware modifications required for plant-specific application if one of the approved Boiling Water Reactor Owners Group long-term stability solution options is currently implemented.

GE Response

The DSS-CD required modifications are assumed based on a transition for plants currently implementing the Option III solution. Other stability solutions, such as the Enhanced Option I-A or I-D, will have to first install the OPRM hardware before implementing the DSS-CD solution.

Hardware changes are not necessary for implementation of DSS-CD on GE Power Range Neutron Monitor (PRNM) systems. The necessary software modifications involve Electrically Programmable Read-Only-Memory (EPROM) changes only.

The OPRM functions defined (in section 3.3.3) in the approved LTR NEDC-32410P, NUMAC PRNM Retrofit Plus Option III Stability Trip Function, will be replaced with DSS-CD functions. Specifically the following changes will be made to the existing PRNM instruments and system:

[[

]]

Table 1 below identifies the GE documents used to control the DSS-CD modifications.

Table 1	
Document Title	**Description**
NUMAC Power Range Neutron Monitoring System, Implementation of DSS-CD for PRNM, Project Plan (Project Quality Plan/Project Work Plan)	This project plan provides the work scope and deliverables for implementation of the new Stability Detect and Suppress Solution - Confirmation Density (DSS-CD). The DSS-CD will be incorporated into the as-built NUMAC Power Range Neutron Monitor (PRNM) system.
Oscillation Power Range Monitor for Stability DSS-CD - Performance Specification	This specification establishes the performance requirements of the OPRM for the DSS-CD.
Oscillation Power Range Monitor for Stability DSS-CD - Data Sheet	This data sheet establishes the ranges and nominal values of the parameters included in the design of the OPRM DSS-CD.
NUMAC Power Range Neutron Monitor System Requirements Specification	This specification defines the design and performance requirements for the design and manufacture of a NUMAC based PRNM system.
PRNM Requirements Specification - Data Sheet	This requirements specification data sheet establishes the specific design requirements for the Brunswick 1&2 NUMAC PRNM systems.
NUMAC Average Power Range Neutron Monitor with DSS-CD, Performance Specification	This specification defines the performance characteristics and application limits for a generic NUMAC APRM instrument that includes the OPRM DSS-CD and automatic BSP functions.
NUMAC Average Power Range Neutron Monitor with DSS-CD, Data Sheet	This performance specification data sheet, in conjunction with the generic specification above defines the performance characteristics and application limits for the Brunswick 1&2 NUMAC APRM.

Table 1	
Document Title	**Description**
APRM (with DSS-CD) Functional Controller Software Design Specification	This document comprises the high-level design of the APRM functional controller software. The purpose of the document is to define the software design in sufficient detail such that software implementation can be undertaken without need for major design decisions. The specification also provides a means for understanding how the functional controller software fulfills design input requirements.
APRM (with DSS-CD) Functional Controller Software Design Specification Data Sheet	This document describes the Brunswick 1&2 APRM functional controller software design by way of listing the exceptions to the parent document.

Generic Licensing Basis – RAI 6

According to the proposed DSS-CD technical specification (TS) changes, each plant would perform testing during the first startup, and shutdown and at intermediate times cycle. The DSS-CD hardware would be bypassed during this testing. Please describe the testing that would be done and the success criteria that would be used.

GE Response

The testing elements and corresponding success criteria are provided in the table below.

Testing Element	Success Criteria
System hardware self testing of the individual hardware modules used in chassis.	[[
Monitoring confirmations during startup.	
Confirming that the OPRM system operates properly under operational maneuvers such as pump upshift.	
Testing to assure that the arming and disarming of the OPRM system occur properly.	]]

It is clarified that DSS-CD may be trip-bypassed while in the DSS-CD Armed Region during the first reactor startup and during the first controlled shutdown that passes completely through the DSS-CD Armed Region. However, DSS-CD shall be OPERABLE and capable of automatically arming consistent with the DSS-CD LTR for operation at recirculation drive flow rates above the DSS-CD Armed Region.

Generic Licensing Basis – RAI 7

Section 6 of the LTR states that "Non-fuel design related changes require a single reasonably limiting best-estimate TRACG case simulation performed according to the procedure of Table 6.2". Please provide the scope of expected changes (e.g. does this statement apply to a new reactor?). In addition, provide the expected NRC review for plant-specific or generic applications when non-fuel design changes occur.

GE Response

Design changes beyond the DSS-CD plant-specific applicability checklist envelope that affect stability performance will require confirmation analysis according to the DSS-CD applicability extension procedure of Table 6-2. Non-fuel design related changes would typically [[

]] This is clarified in the updated Section 6.0 of the DSS-CD LTR.

<u>Confirmation Analysis Methodology – RAI 1</u>

Please describe the detailed process of confirmation analysis performed with TRAC-G to calculate the reactor scram time and the final minimum critical power ratio (MCPR). Compare it with the physical signal processing steps and discuss the consistency between the numerical signal data process simulation and the physical process. In Table 4-3, it is stated that the hot channel neutron flux trace is used to identify the base period. Please provide the basis that the scram time predicted based on the hot channel neutron flux is more conservative than using low power range monitors (LPRM)/operating power range monitors (OPRM) signals.

<u>GE Response</u>

Reactor oscillations are expected to become coherent for both the regional and core-wide modes when the decay ratio is approaching 1.0. This implies that the whole core will be oscillating either out-of-phase or in-phase once the reactor instability threshold is reached. In particular, for events that are inherently unstable at the initial off-rated conditions, the entire core will quickly assume a coherent oscillatory behavior. [[

]] the oscillations are fully coupled and the entire core is participating.

[[

]] The effectiveness of the PBA for a combination of signals (e.g., LPRM to OPRM performance) is demonstrated in the DSS-CD based on actual plant data, illustrated in Figure 5-4.

[[

]] These two channels are located in the least responsive portion of the core for regional mode oscillation; this situation is fully expected and the LTR methodology explicitly assumed that OPRM cells along the axis of symmetry are unresponsive, and are not accounted for when establishing the confirmation density. [[ ]] This indicates that when the entire core is oscillating in a coupled manner the time of confirmation is not dependent upon channel power level or channel location other than areas close to the axis of symmetry for regional mode oscillations. [[ ]]

The TRACG model used to estimate the reactor scram time is based on [[ ]] Hence, the power suppression time is about [[ ]] including the base period recognition time.

[[ ]] Therefore, the DSS-CD hardware/software design and the analytical simulation are consistent.

Figures 3 and 4 provided below show the location of the LPRM signals for the Columbia plant. The number in each cell provides the order in which each LPRM signal reaches the successive period confirmation count setpoint [[ ]] for the instability event corresponding to Figures 5-4 and 5-5 of the DSS-CD LTR. [[ ]]

[[

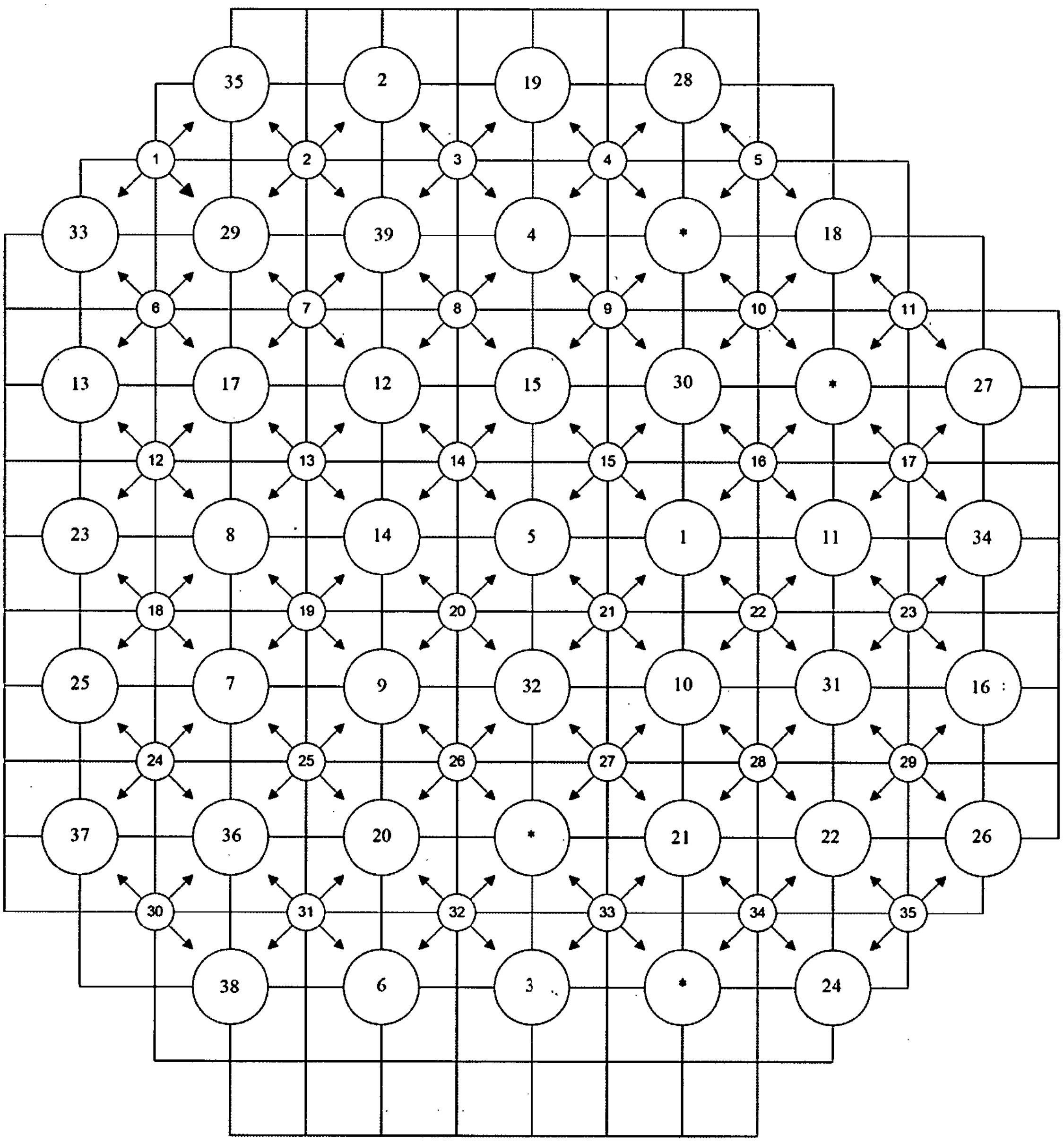
]]

[[

]]

[[

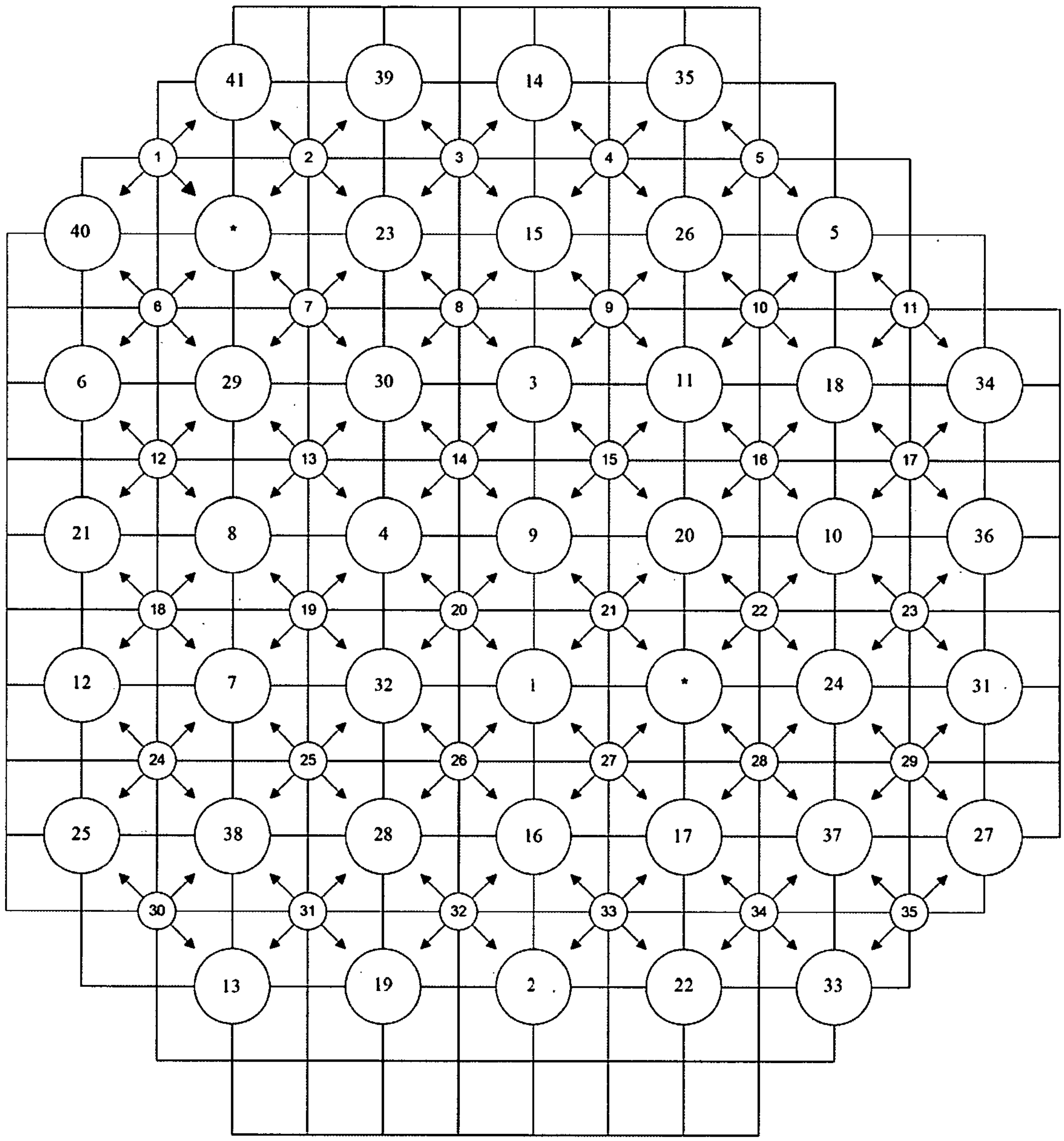
]].



*Data not available

764 Bundle Core, OPRM Channel 1

Figure 3.



*Data not available

764 Bundle Core, OPRM Channel 2

Figure 4.

Confirmation Analysis Methodology – RAI 2

All the calculations in NEDC-33075P, Rev 2, are noise-free. In real life, boiling water reactors (BWR) LPRMs have a ~3% noise level, which could interfere with the DSS-CD algorithm and produce spurious resets. What is the impact of ~3% noise on the time to scram? Provide a rationale why the noise-free calculations are sufficient to simulate the performance of the DSS-CD scram and protection of specified acceptable fuel design limits (SAFDL).

GE Response

LPRM signal data, based on an actual instability event, shows that the LPRM signals become increasingly coherent upon approach to the instability threshold. The data also shows that the effect of the LPRM noise is minimized and virtually non-existent when coherent oscillation is present (at decay ratios close to 1 or higher). This is demonstrated in the DSS-CD LTR, Figure 5-4, where an actual plant event shows practically no noise at the instability inception, where the relative oscillation amplitude is less than 3% peak to peak (the absolute peak to peak oscillation magnitude is less than 1% of rated). In addition, any residual high frequency noise is effectively filtered by the conditioning filter employing the two-pole Butterworth filter algorithm. The effect of conditioning filter is shown in Figures 6-1 and 6-2 of *NEDC-31960-A Supplement 1, Licensing Topical Report BWR Owners' Group Long-Term Stability Solutions Licensing Methodology (Supplement 1), November 1995.*

A high degree of coherence is expected for OPRM signals for anticipated modes of oscillation (regional and core wide) with the entire core participating in the oscillation. In particular, for reasonably limiting events where the initial off-rated conditions following the flow runback are inherently unstable, the noise effect is expected to be promptly minimized. The conditioning filter further removes any residual high frequency noise components from the signals. For the method demonstration case (DSS-CD LTR Figure 5-8), the reactor is unstable immediately following the flow runback. Oscillatory behavior is initiated at around 23 seconds in the figure. The oscillations for the first 10 seconds are not fully coupled as the core is transitioning to a fully coherent regional mode oscillation. At that time (around 34 second in the figure) the core is fully coupled, the relative oscillation amplitude is similar to that observed for the actual plant event of Figure 5-4, and the confirmation count commences. Hence the effect of LPRM noise on the oscillation count initiation and the time of the scram are minimal, and the "noise-free" TRACG simulation is reasonable for determining the final MCPR.

Confirmation Analysis Methodology – RAI 3

What are the basis and numerical schemes for the harmonic mode power grouping used in the CLPS code? Please provide mathematical formulations and discussions. In addition, provide the mathematical formulation for the core wide mapping scheme.

GE Response

The requested information has been provided by MFN 03-016, "Response to Request for TRACG Inputs for MELLLA+ and DSS-CD LTR Review (TAC Nos. MB6157 & MB5705)," dated March 11, 2003 in the document, GE-NE-0000-0013-2189-R1.

Confirmation Analysis Methodology – RAI 4

Please provide information about how the PANACEA code calculates the harmonic power distribution.

GE Response

The requested information has been provided by MFN 03-118, "Response to Request for Information on PANACEA Harmonic Calculation (TAC No. MB5705)," dated October 31, 2003 in the document titled "Harmonic Modes of Neutron Flux."

BSP Methodology – RAI 1

A simple extrapolation of the Region II "Controlled Entry" line of Figure 7-3 shows that this region would be very close to the maximum extended load line limit analysis plus (MELLLA+) upper boundary. The regions illustrated in Figure 7-3 are the base minimal regions; thus, the actual regions in MELLLA+ reactors cannot be smaller. What is the rationale for not calculating the stability of a new point (call it C') at the MELLLA+ upper boundary line and confirming that the MELLLA+ allowed operating domain is not inside the controlled entry region?

GE Response

DSS-CD LTR Section 7.2 defines the Manual BSP Region generation process based on the licensing HFCL. For MELLLA+ applications this licensing HFCL is the MELLLA+ upper boundary and its extension to the natural circulation line. Therefore, the determination of the Manual BSP Regions, including Manual BSP Region II, addresses the concern. For clarification, Section 7.2 has been revised to clarify the use of the MELLLA+ HFCL for MELLLA+ applications to include an explicit definition.

It is noted that Point A' for MELLLA+ was determined based on the MELLLA+ upper boundary line extended to the natural circulation line. However the Manual BSP Region II boundary is shown only in the licensed operating domain.

BSP Methodology – RAI 2

Table 7-1 describes the calculation procedure to determine the BSP. Please, specify what is meant by "constant Xenon at rated conditions" for points A and B. Is it exactly the same Xenon concentration in every 3-D node of the core, or is it the 3-D Xenon distribution at rated power, which is kept constant as the flow is reduced?

GE Response

Xenon concentration is determined on a node-specific basis. For the Manual BSP region determination, the decay ratio calculation at points A and B assumes a 3-D Xenon distribution corresponding to the rated power conditions. This assumes that the change in Xenon concentration following a [[

]]

BSP Methodology – RAI 3

Table 7-1 - please, specify what is meant by "equilibrium Xenon" for point A'. Xenon transients take 24 to 48 hours to be significant. What is the probability of steady- state operation at point A' for more than 24 hours? The most likely scenario is either Xenon-free (a fast startup) or equilibrium Xe at rated conditions (a flow reduction.) Please, justify your choice and provide a rough estimate of the impact on the calculated regions if other Xenon distributions are assumed.

GE Response

Table 7-1 provides key assumptions for calculating the Manual BSP regions. For state point A', the Xenon concentration is assumed to be at its equilibrium value at its off rated conditions. It is assumed that this point, or nearby statepoints, are reached during planned operations along the startup path. For events initiating from rated conditions and terminating near Point A', since it takes 24 to 48 hours for Xenon to reach its equilibrium value, it is more conservative to use the off-rated value than assume a Xenon concentration at rated conditions. A Xenon free condition at this state point would require reaching this point through a fast startup, which is not considered plausible. The impact of the Xenon concentration assumption on the calculated decay ratio is expected to be less than 0.005. Since the decay ratios near statepoint A' vary slowly with core flow/power, the size of Manual BSP Region II is expected to be impacted by less than 2% in core flow or power.

BSP Methodology – RAI 4

Table 7-1, Feedwater Temperature - what is the rationale for using rated-power feedwater temperature? The time constant for feedwater temperature transients is two to three minutes, at most five. Entry to Region II will require immediate operator action, which means within 15 minutes; thus, there is plenty of opportunity for the feedwater temperature to reach equilibrium before the operator maneuvers the reactor outside the region. Provide a rough estimate of the effect of your choice of feedwater temperature on the final region sizes.

GE Response

Table 7-1 provides key assumptions for calculating the Manual BSP regions. For Manual BSP Region I, rated feedwater temperature, prior to run back, is assumed. The basis for this assumption is that entry into Manual BSP Region I is from an uncontrolled flow reduction event from rated conditions. In cases where the uncontrolled entry is presumed from off-rated conditions, such as inside or near the Manual BSP Region II boundary, the operator is already monitoring the reactor for power oscillation, and since the initial conditions prior to the flow runback are stable, these cases are considered less challenging than the rated cases. It is expected that upon uncontrolled flow runback to inside Manual BSP Region II the operator will quickly recognize the situation and will promptly initiate actions to exit the region. Plant events such as flow runback from rated conditions to inside Manual BSP Region I can be immediately recognized by the operator based on operator training for recognition of stability region entry.

Per the ICA recommendations, the following licensee actions are required as part of the Manual BSP Regions implementation:

1) The operators should be trained and retrained to scram the reactor when thermal-hydraulic oscillations are observed. The training should emphasize that a scram is required, even if the magnitude is below 10% on the APRMs and LPRM upscale or downscale alarms have not occurred.
2) The operators should be trained and retrained on how to recognize thermal-hydraulic oscillations.
3) The operators should be trained and retrained on the Manual BSP regions and required operator actions within these regions.
4) The operators should be trained and retrained that these Manual BSP region boundaries are not an absolute indicator of the potential for instability under all conditions.

Operator actions to initiate exit from Manual BSP Region II are expected to commence as soon as the event is recognized. In the unlikely situation where instability events may develop inside Manual BSP Region II, they are expected to evolve slowly, as the feedwater temperature progresses towards its equilibrium value, providing the operator sufficient time to initiate reactor scram.

Since reasonably bounding assumptions are used to determine the regions, assuming the off-rated feedwater temperature to evaluate the Manual BSP Region I boundary would increase its size to approximately the Manual BSP Region II boundary, potentially resulting in an increase in unnecessary scrams not related to the potential onset of instability.

Note of clarification: the separation between the boundaries of Manual BSP Regions I and II, unlike the ICAs, is not fixed. The separation is expected to vary by plant and cycle. This is expected because the generating process of these regions takes into account the plant specific stability performance as compared to the specified stability criterion. The Manual BSP Regions may be generated for reduced feedwater temperature (FWT) operations. The reduced FWT may result in significantly larger regions. In some cases, the separation between the two region boundaries may decrease to a few percent because of the smaller difference between the rated and off-rated FWT for reduced FWT operation. This behavior demonstrates the difference between the prescribed ICA-based regions and the BSP-generated regions, which provide a more realistic representation of the plant stability performance.

BSP Methodology – RAI 5

NEDC-33075P does not specify the point in the cycle used for the BSP regions calculation. Will these calculations be performed for an end-of-cycle all-rods-out condition? Provide the rationale for your choice.

GE Response

The Manual BSP regions are calculated based on the ODYSY methodology as outlined in NEDC-32992P-A, ODYSY Application for Stability Licensing Calculations, July 2001. These calculations are performed [[ ]] with the limiting exposure chosen. As outlined in NEDC-32992P-A, [[

]]

DSS-CD LTR Table 7-1 has been revised to include the cycle exposure parameter and calculation procedure specifying selection of limiting cycle exposure.

BSP Methodology – RAI 6

Please, provide the proposed methodology to define the BSP Line. Address the following issues:

a) Calculation procedure, including reactivity coefficients, Xenon, feedwater temperature ... (with a level of detail similar to Table 7-1 of NEDC-33075P, Rev. 2)
b) Calculation methodology. Describe how the calculation will be performed. For example: (a) type of code (steady-state versus. transient ...), (b) what type of calculation is performed, (c) what results are we looking for, (d) how do you define success in the iterative method (any specific criteria?).
c) Provide a link to the existing BSP methodology in the LTR. Specifically, what BSP regions (as defined in the LTR) are used in the new BSP line methodology.
d) Results of the BSP Line Methodology. Specifically, how will the BSP line be defined in the core operating limits report (COLR) (a straight line, a curved polynomial, ...)

GE Response

The response to this RAI was originally provided in GE letter, MFN 04-001 [Ref. 14], dated January 23, 2004. Subsequently in GE letter, MFN 05-148, dated December 7, 2005 [Ref. 15], GE committed to update the response to reflect changes made in a subsequent revision to the DSS-CD LTR. The updated response is a follows:

The Section 7 of the DSS-CD LTR has been updated to provide the Backup Stability Protection (BSP) methodology. The BSP Boundary, formerly termed 'BSP Line' defines the operation domain where potential instability events can be effectively addressed by specified operator actions, and is an element of one of the two BSP options.
A description of the BSP Boundary is provided in the updated DSS-CD LTR, including BSP Boundary assumptions, generation process, and plant specific application.

Subsequent revisions to the LTR have added Table 7-2 to address item a of the RAI and Section 7.3.1 to address items b, c, and d of the RAI

BSP Methodology – RAI 7

For the cases in chapter 4 of NEDC-33075P, Rev. 2, provide an illustration of the time when the scram would occur if automated BSP were active. Are SAFDLs satisfied by the automated BSP option for all cases by preventing the oscillation before it occurs?

GE Response

Figures 7-9 and 7-10 of the updated DSS-CD LTR illustrate the effect of the early scram capability made available by the Automated BSP Scram Region feature. Based on the core flow response for the 2RPT event simulation shown in Figure 4-1, the modified APRM flow-biased scram setpoint is reached in 5 to 10 seconds after the pump trip initiation. This is based on an assumed modified APRM flow-biased scram setpoint above the NCL at approximately 40% to 50% rated core flow. The APRM setpoint is implemented as a function of the recirculation drive flow and is selected to properly represent the APRM setpoint as a function of core flow. Therefore, within approximately 5 to10 seconds from the 2RPT event initiation, the APRM flow-biased scram setpoint encompassing the Manual BSP Region I would be intercepted, resulting in an immediate automatic scram. The channel CPR continuously improves during the flow runback portion of the event and oscillation is still undeveloped during the time interval between RPT and reactor scram. The Automated BSP Scram Region feature provides SLMCPR protection through oscillation prevention.

BSP Methodology – RAI 8

Section 7.5 of NEDC-33075P Rev 2 contains a number of "may" statements. Are any of these statements a required option for licensees implementing automated BSP? If so, NEDC-33075P, Rev. 2 will need to be more specific.

GE Response

The Section 7 of the DSS-CD LTR has been updated to eliminate the use of "may" statements were action are required while retaining its use where appropriate to provide needed flexibility.

BSP Methodology – RAI 9
Provide a more specific description of the proposed flow-biased scram region. NEDC-33075P, Rev 2 only states that it will encompass Region I. Please be more specific on the implementation details.

GE Response
The Manual BSP Scram Region (Region I), established based on the calculation procedure described in Section 7.2 of the DSS-CD LTR provides the analytical limit for the Automated BSP Scram Region implementation. Plant-specific setpoint methodology and the cycle-specific Manual BSP Scram Region generation process determine the allowable modified APRM flow biased scram region setpoints to be implemented in the COLR.

BSP Methodology - RAI 10
Provide a short statement on the rationale why the use of the non-safety grade drive flow signal is adequate for this application.

GE Response
The NRC evaluated the flow channel requirements as part of the review of Licensing Topical Report 31960-A, "BWROG Long Term Stability Solutions Licensing Methodology." The NRC's conclusions are documented in section 3 Conclusions, sub-item (3) of the SER for that LTR.

The DSS-CD uses an alternate logic algorithm from those discussed in LTR 31960-A, but is otherwise accomplishing the same function in the plant. The BSP is a special case alternate that can be invoked under certain conditions. Therefore, the conclusions of the NRC review of LTR 31960-A also apply to DSS-CD and the BSP.

The NRC evaluation of LTR 31960-A concluded that the recirculation drive flow channel should comply with the requirements of IEEE 279 including single failure criterion, component quality, channel independence, and capability of test and calibration. The NRC further concluded that isolation devices needed to be qualified (if isolation devices were necessary to isolate a non-safety-related recirculation flow channel from safety-related equipment/functions).

The only equipment items involved in the recirculation drive flow channel are the flow transmitter typically located in the reactor building and the transmitter signal processing equipment, typically located in the plant control room or similar equipment area. The recirculation drive flow signal is used in the APRM systems to provide the setpoint for a flow-biased scram trip function. The requirements associated with that function are unchanged by addition of DSS-CD with BSP.

The function of non-safety-related flow transmitters and safety-related flow transmitters are no different. The performance and operating environmental requirements , except for accident conditions, are also no different. The primary difference is that safety-related flow transmitters may need to be qualified to operate under accident conditions or environments resulting from an accident. Specifically, a non-safety-related flow transmitter may not continue to operate under HELB or LOCA conditions, but these conditions do not occur simultaneously with the conditions for which the DSS-CD or BSP Trip Function is credited with providing a scram trip. Therefore, the "component quality" requirements of IEEE 279 relative to the DSS-CD and the BSP function are satisfied. The equivalent requirements for the APRM flow-biased scram functions are also satisfied provided the existing flow transmitters are utilized or that any replacement flow transmitters are of equivalent quality level to those currently installed. (A replacement might be necessary or have been performed if the current transmitters are 10-50 mA range, in which case they may be replaced with more common 4-20 mA output range transmitters.)

Control room or equipment room mounted equipment is not exposed to accident environments. Therefore, existing control room flow channel signal processing equipment, or replacement equipment of similar or better quality level, also satisfies the IEEE 279 component quality requirements.

Channel independence and single-failure criterion are satisfied at the system level, independent of the specific quality level of equipment components provided there are no common mode failures due to environmental conditions that might occur concurrently with the need for the system function. As discussed above, there are no accident environments that will occur concurrent with an instability event. Although the commonly available flow transmitters that satisfy the functional and environmental requirements for the nuclear plant application are unlikely to fail during a seismic event, the original evaluation of LTR 31960-A recognized that the probability of a significant seismic event occurring concurrently with an instability event was sufficiently unlikely to obviate the need for a seismically qualified recirculation drive flow channel for the stability trip function. The channel independence and single failure criterion related to the APRM flow-biased trip function are unchanged by the additions of DSS-CD and BSP. Further, the channel independence and single failure criterion related to the DSS-CD and BSP functions are unchanged from those related to an Option III stability solution. Therefore, if a plant has previously implemented an NRC approved Option III stability solution, the currently installed flow channel configuration is adequate for DSS-CD and BSP. If a plant has not previously implemented an Option III stability solution, part of the change process will need to be a review of channel independence and single failure criterion conformance.

The capability for test and calibration is a functional issue that must be satisfied, but is independent of the qualification level of the equipment implementing the recirculation flow channel. Further, those requirements are already applied as part of the use of the recirculation flow channel as an input to the APRM, and are unchanged by the addition of DSS-CD and BSP.

Generally, the isolation requirements for the recirculation flow channel are unchanged with the addition of DSS-CD and BSP. However, if a new interface is created, different from the interfaces currently existing between the recirculation flow channel and the APRM, adequacy of the isolation function at that new interface will need to be addressed as part of the plant-specific application.

For plants implementing GE's NUMAC Power Range Neutron Monitoring system with the DSS-CD and BSP or adding the DSS-CD and BSP, no additional isolation is required. The recirculation drive flow signal processing equipment is integrated into the APRM equipment and qualified to the same levels as the APRM equipment. The interface with the flow transmitters limits the energy and fault propagation such that no credible failure in the flow transmitter can result in other than an erroneous signal, which in most cases will be immediately identified. Evaluation of the channel independence and single failure criterion conformance is performed as part of the APRM modification.

BSP Methodology – RAI 11

Provide the licensing basis for the automated BSP option. Explain how the automated BSP option will protect safety limits for reasonable events that initiate at rated power as well as startup events. Explain how the choice of criteria for region definition provides protection for intermediate power levels.

GE Response

Automating BSP Scram Region provides licensing basis SLMCPR protection by providing instability prevention protection for the entire licensed operating domain including MELLLA+. The Automated BSP Scram Region is based on the Manual BSP Region I definition, [[ ]] Because the Manual BSP Scram Region boundary intersection with the plant specific NCL is not higher than the intersection of the original 100% load line with the plant NCL, flow reduction events from the MELLLA+ region to the NCL would result in an entry into the Automated BSP Scram Region, and therefore an automatic reactor scram. In addition, any flow reduction event initiating from off-rated conditions and terminating inside the Automated BSP Scram Region, including all events terminating above the OLTP 100% load line, results in immediate automatic reactor scram.

Steady state operations at off-rated conditions may be associated with feedwater temperature lower than rated, and therefore, may result in a statepoint below the Manual BSP Scram Region confirmation statepoint, [[ ]] However, operation at off-rated conditions is limited in duration and the confirmation of the Manual BSP Region II at the high flow end is based on a stability criterion associated with a 0.6 decay ratio, resulting in improved stability margin. Therefore, the Automated BSP Scram Region definition, which is conservatively constructed based on the Manual BSP Region I, in conjunction with the definition of the Manual BSP Region II, is acceptable.

BSP Methodology – RAI 12
Provide a justification why the BSP Boundary is implemented as a straight line.

GE Response
The BSP Boundary is defined as a straight line, [[

]]
This is illustrated in the example BSP Boundaries provided in Section 7 of the LTR.

Request for Additional Data – RAI 1

Provide the FORTRAN codes that simulated the DSS-CD algorithm for the calculations in the Confirmation Event Matrix (e.g., PERIOD code). Please provide the associated documents describing the input/output, internal algorithm and sample input/output files. Also, provide a flow chart to describe their relationship for the calculation. Does the PERIOD code include a Butterworth filter algorithm to simulate the cutoff frequencies that are available in the PBDA hardware? If not, provide the filter algorithm code used by the PBDA. Demonstrate the capability of the PERIOD code to calculate the confirmation counts for a given oscillation signal.

GE Response

The PERIOD code files including the source code, executable, sample input, output and command file have been provided by MFN 03-021, "Period Code Files for DSS-CD for LTR Review – Proprietary Information (TAC No. MB5705)," dated April 3, 2003 in the CD labeled, "PERIOD Code Files for DSS-CD".

The flow diagram showing the relationship of the PERIOD code to the TRACG data is provided below.

[[

]]

Request for Additional Data – RAI 2

Please provide the graphical interval size for the TRACG power oscillation signal passed into the "PERIOD" code. Also, provide input deck for the final verification of the PERIOD code.

GE Response

The graphical interval sizes used in the various TRACG cases for DSS-CD are provided in the table below.

[[

]]

Request for Additional Data – RAI 3

Can an LPRM signal be simulated using TRAC-G control system I/O variable? If it does, what is the unit of the I/O variable?

GE Response

An LPRM signal may be simulated using the corresponding TRACG control system I/O variable. The LPRM variable is dimensionless. Variable LPRM is the average of the surrounding nodal power distribution values. The 3D nodal power distribution is normalized such that the average nodal power is 1.

Request for Additional Data – RAI 4

Please provide the BWR-4 regional oscillation case TRAC-G input decks and sample output files.

GE Response

The BWR 4 TRACG information has been provided by MFN 03-016, "Response to Request for TRACG Inputs for MELLLA+ and DSS-CD LTR Review (TAC Nos. MB6157 & MB5705)," dated March 11, 2003 in the CD labeled, "BWR4 (Brunswick) TRACG Analysis Inputs for DSS-CD Application".

Request for Additional Data – RAI 5

It was indicated that a written procedure has been in-place to direct an analyst to perform manual mapping adjustment based on CLPS code output. Please provide this document and discuss the criteria used.

GE Response

The requested information has been provided by MFN 03-016, "Response to Request for TRACG Inputs for MELLLA+ and DSS-CD LTR Review (TAC Nos. MB6157 & MB5705)," dated March 11, 2003 in the document, GE-NE-0000-0013-2189-R1.

<u>Technical Specifications – RAI 1</u>
Provide the generic TSs required for a DSS-CD implementation

<u>GE Response</u>
Technical Specifications to be used as generic guidance in developing a plant-specific license amendment to address DSS-CD implementation is provided in Section 8 of Revision 3 of the DSS-CD LTR. Differences in plant-specific changes to the TS and Bases from those examples provided may be justifiable based on the plant-specific licensing basis and the inclusion of other licensing basis changes in the plant's license amendment request.

The example Technical Specifications assume implementation of the TS and Bases proposed for BWR/4 Improved Technical Specifications, Rev. 1, 4/7/95, in NEDC-32410P, "Licensing Topical Report Nuclear Measurement Analysis and Control Power Range Neutron Monitor Plus Option III Stability Trip Function," Supplement 1, November 1997. The example Technical Specification address:

1. Implementation of the Backup Stability Protection (BSP) in the event that the DSS-CD is inoperable,
2. Changes in the applicability requirements for DSS-CD,
3. Initial operation of the DSS-CD,
4. Elimination of an unnecessary Surveillance Requirement,
5. Additional core operating limits to the Core Operating Limits Report,
6. Reporting requirements for inoperable DSS-CD, and
7. Update the applicable references.

Technical Specifications – RAI 2

Timing for TS LCO 3.3.1.1 Action I.1 - please, provide the basis for allowing 12 hours to initiate alternate method of detection (BSP). With the proposed TSs, if DSS-CD is declared inoperable, there is a gap of 12 hours until BSP protection is in place. For those 12 hours (irregardless of the probability of an instability event) no protection is in place. Specifically, justify why the completion time for Action I.1 should not be "**immediately**".

GE Response

Action I.1 of the example Technical Specification 3.3.1.1 was revised in Revision 3 of the DSS-CD LTR. The Action and Completion Time was revised to immediately initiate action to implement the Manual BSP Regions, which are procedurally established consistent with the guidelines identified in Section 7 of the DSS-CD LTR and require specified manual operator actions based on certain predefined operational conditions.

Technical Specifications – RAI 3

Timing for TS LCO 3.3.1.1 Action I.2.2 - please, provide the basis for allowing 14 days to initiate action to reduce operation to below the BSP boundary. Specifically, justify why the completion time for Action I.2.2 should not be "**immediately**".

GE Response

Action I.2.2 of LCO 3.3.1.1 is replaced with a revised Action and new Completion Time in Revision 3 of the DSS-CD LTR. As discussed in Section 7 of Revision 3 of the DSS-D LTR, Backup Stability Protection requires either the implementation of the BSP Boundary or Automated BSP Scram Region in conjunction with the Manual BSP Regions. The site-specific license amendment request would specify the particular approach to BSP. The generic Completion Time for implementation of BSP is 12 hours.

Technical Specifications – RAI 4

Required channels per trip system - Table 3.3.1.1-1, Function 2-f, defines the number of OPRM upscale channels required per trip system as "3 APRMs". Please, provide the rationale behind this requirement. Explain why the requirement should not be the number of OPRM channels that must be operable.

GE Response

A description of the Function 2-f requirement is provided in the Tech Spec Bases, Section B 3.3.1.1 in NEDC-32410P, "Licensing Topical Report Nuclear Measurement Analysis and Control Power Range Neutron Monitor Plus Option III Stability Trip Function," Supplement 1, November 1997.

The hardware is configured such that APRM and OPRM share the same channel; therefore the specification in Table 3.3.1.1-1 is technically accurate.

Technical Specifications – RAI 5
Evaluate if the safety limit MCPR and the operating limit MCPR applicability range given in Section 4.3, "Generic Applicability Envelope," should be included in the TS in accordance with 10CFR50.36 requirements.

GE Response
The SLMCPR and OLMCPR are plant/cycle specific parameters that are determined during the reload design and analysis process prior to cycle operation. The assessment to confirm the validity of the generic basis of the LTR is, therefore, performed at that time (i.e., during the reload design and analysis process prior to cycle operation). The following statement is included in Section 6.1 of the DSS-CD LTR:

> The standard plant specific review process, which also applies to the reload process, consists of an applicability checklist, confirming that the generic applicability envelope, as defined in Section 4.0, is not exceeded. The plant specific applicability checklist is provided in Table 6-1.

The OLMCPR-SLMCPR relationship does not change during the cycle and there is no need to consider it as a process parameter, design feature, or operating restriction as used in 10CFR50.36 (c)(2)(ii)(B).

Technical Specifications – RAI 6

TS 5.6.5 Core Operating Limits Report - TS 5.6.5.a shall be listed a cycle-specific parameter relating to core operating limits. The proposed TS changes should follow the guidance specified in the Generic Letter 88-16 and TS 5.6.5 shall be listed the NRC approved topical reports to support the cycle-specific parameters listed in TS 5.6.5.

GE Response

The cycle specific BSP parameters are included in the proposed TS 5.6.5 a as follows:

> The Manual Backup Stability Protection (BSP) Scram Region (Region I), the Manual BSP Controlled Entry Region (Region II), [the modified APRM flow-bias setpoints used in the Automated BSP Scram Region, or the BSP Boundary] for Specification 3.3.1.1

The analytical methods defined in b. currently reference the NRC approved GESTAR topical report, which defines the codes and methods used in the reload process that produces the COLR. The proposed TS approach follows the guidance in Generic Letter 88-16.

Nine Mile Point 2 Event – RAI 1

Provide a summary of the impact of the Nine Mile Point on the DSS-CD methodology. What is the expected performance of DSS-CD under the observed Nine Mile Point 2 event conditions?

GE Response

On July 24, 2003 the Nine Mile Point-2 (NMP-2) underwent a plant transient that initiated from rated power condition and resulted in an instability event, eventually terminated by an Option III OPRM system initiated scram. An early Option III alarm was received at approximately 320 seconds following the initial core power and flow reduction, associated with a mild low amplitude oscillatory behavior. Approximately 60 seconds later, a coherent thermal-hydraulic core-wide oscillation mode had developed, which resulted in a reactor scram at approximately 420 seconds into the event. Subsequently, an analysis of the DSS-CD oscillation detection capability was performed to assess how DSS-CD would have performed under the NMP-2 instability event conditions. Signals from 30 OPRM cells from two OPRM channels were evaluated to determine the Confirmation Density (CD) of the OPRM channels. Since the event raw input signals were unavailable, the processed OPRM cell signals were re-evaluated. The effect of the selected conditioning filter cutoff frequency, variation in the period tolerance, including the DSS-CD period tolerance offset feature, were evaluated. A summary of this analysis is provided.

Figure 1 provides the CD responses based on the Period Based Algorithm (PBA) implemented in DSS-CD. The PBA for DSS-CD defines the base period as equal to the last confirmed period, assumes a larger oscillation period time window (relative to Option III), and uses a conditioning filter cutoff frequency of 1 Hz and period tolerance of 100 milliseconds. Successive Confirmation Count (SCC) setpoint [[ ]] is assumed. The results show that the CD setpoint (assumed as 5 OPRM cells per OPRM channel) is reached around 414 sec, for both OPRM channels as soon as the core begins to exhibit coherent oscillatory behavior, and close to full channel participation is observed at the final phase of the event just prior to the scram (the core power and flow reductions were initiated at approximately 120 seconds). With a period tolerance of 50 milliseconds, used for comparison purposes, the PBA is not as responsive, although one OPRM channel reaches the CD setpoint around 418 seconds during the initial low level oscillations and both OPRM channels exceed the CD setpoint at the final phase of the event just prior to the scram.

Figure 2 provides the corresponding CD responses based on the PBA implemented in Option III (1Hz conditioning filter cutoff frequency and 100 milliseconds period tolerance are assumed to provide a valid comparison). The CD response corresponding to 100 millisecond period tolerance from Figure 1 is included in Figure 2 for comparison purposes. Based on the CD responses provided in Figure 2, the use of PBA for DSS-CD is consistently more responsive and leads to earlier oscillation recognition and scram, relative to the use of PBA for Option III.

DSS-CD introduces a feature designed to maximize the ability of the PBA to recognize the initiation of oscillations following a fast flow runback event. This is accomplished by automatically setting the period tolerance to 300 milliseconds for duration of 90 seconds following inadvertent flow reductions from outside the OPRM Armed Region. The effect of this feature is demonstrated for the NMP-2 event in Figure 3. The NMP-2 event was initiated by a fast flow runback event, which if DSS-CD were implemented, would set the period tolerance to 300 milliseconds for 90 seconds. In the case of the NMP-2 instability event, coherent oscillation did not develop immediately following the flow runback. Therefore the period tolerance would have been set back to 100 milliseconds before the reactor scram. However, to demonstrate the effect of 300 millisecond period tolerance, Figure 3 provides the CD responses assuming the 300 millisecond period tolerance for the entire indicated duration. A comparison of the CD responses corresponding to different period tolerance assumptions indicates a significantly more responsive detection capability with the period tolerance offset feature, confirming the expected system sensitivity. More importantly, Figure 3 demonstrates that for stable reactor operation, the 300 millisecond period tolerance offset value did not result in a spurious trip signal prior to the expect time of offset reset to 100 milliseconds. In addition, application of a period tolerance of 100 milliseconds to the entire event did not result in any increase of the confirmation density above zero until the time of the initial low amplitude temporary oscillations. This is an excellent demonstration of the CD performance, which is associated with CD = 0 during stable operations and CD > 0 when oscillations develop.

Based on the above analysis, it is concluded that DSS-CD would have provided the expected and adequate protection under the NMP-2 instability event conditions with the algorithm settings and setpoints specified in the LTR. The results of the analysis demonstrate an improvement in oscillation detection capability for DSS-CD relative to Option III and CDA performance consistent with expectations.

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Figure 1. CD Response Based on PBA for DSS-CD

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Figure 2. CD Response Comparison Based on PBA for DSS-CD and PBA for Option III

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Figure 3. Effect of DSS-CD Period Tolerance Offset Feature on the CD Response

NRC RAI 1

Any Long Term Solution that relies on the DIVOM methodology (e.g. Solution III) has problems if even a small number of hot channels become unstable before scram. A possible scenario is a recirculation pump trip - when the flow reaches a threshold, the core becomes unstable and responds neutronically; however, due to the detection time delays, the flow continues to decrease and a number of hot channels become unstable as operating condition reaches deeper into the unstable region. Please describe any impact on the DSS-CD solution of this type of scenarios.

GE Response

The DIVOM correlation relies on a relationship between the change in channel CPR and the change in channel power. If the channels are hydraulically unstable, the DIVOM slope will be very steep resulting in OPRM setpoints so low that the Option III might be inoperable. In the DSS-CD solution, no such relationship is assumed. The reactor is tripped at the earliest indication of instability, 10 confirmation counts with amplitude of 1.03 (at or slightly above the noise level). Because the core is neutronically coupled at the inception of instability, and the coupling increases as operating condition reaches deeper into the unstable region, sufficient neutronic response exists to allow the period confirmation count to proceed. Upon instability inception the actual power amplitude tends to immediately increase, thereby, quickly exceeding the DSS-CD amplitude discriminator (i.e., 1.03), resulting in a scram signal with very little delay, and without significant CPR degradation. Therefore, there is no impact on the DSS-CD solution capability to provide SLMCPR protection in entering regions where the core and/or channels are highly unstable.

An additional difference between Option III and DSS-CD is that Option III uses one leading cell as opposed to 5 cells in DSS-CD. The use of 5 cells in DSS-CD enables the solution to distinguish between plant noise and an actual instability event. This allows DSS-CD to have a lower OPRM amplitude set point making the DSS-CD solution more responsive.

NRC RAI 2
Normally a SLO SLMCPR value is 0.01 or 0.02 higher than the TLO SLMCPR value. Please clarify why a same SLMCPR value is used for both Table 4-1 TLO and Table 4-6 SLO in terms of a practical application for DSS-CD MCPR margin.

GE Response
The DSS-CD solution applicability does not depend upon a plant's specific SLMCPR or OLMCPR but on the margin between the two as stated in Section 4.3 of the LTR. For TLO the solution is demonstrated to be applicable for plants whose

$$\frac{OLMCPR_{Rated}\text{-}SLMCPR}{OLMCPR_{Rated}} > 0.067$$

and for SLO the solution demonstrated to be applicable for plants whose

$$\frac{OLMCPR_{SLO}\text{-}SLMCPR}{OLMCPR_{SLO}} > 0.138$$

For the DSS-CD demonstration TRACG cases, a common SLMCPR value of 1.12 is used for both TLO and SLO. However, when determining the applicability of the DSS-CD generic applicability envelope for a specific plant, the above relationships are used with the plant-specific TLO and SLO OLMCPR and SLMCPR.

NRC RAI 3

On page 7-5, a typo shows that A' should be A in Figure 7-1.

GE Response

This is not a typo. The BSP methodology for Region II (Controlled Entry Region) is for the stability criterion associated with 0.8 core and channel decay ratios to be applied to point B' and the stability criterion associated with 0.6 core and channel decay ratios to be applied to point A'. Figure 7-1 correctly shows BSP Regions I and II and the associated points A, B, A', and B'. The 0.6 criterion is used for point A' rather than 0.8 to provide additional stability margin for operation at off-rated conditions.

NRC RAI 4
On page 9-1, References 8 and 9 should be reviewed and approved by NRC.

GE Response
References 8 and 9 have been submitted to and were reviewed as part of the approval of NEDE-32906P-A, which is Reference 7 in the DSS-CD LTR.

NRC RAI 5

On page A-3, final position statement for I.3 should be included.

GE Response

Revision 5 of the DSS-CD LTR was issued in GE Letter, MFN 05-145, dated December 1, 2005, includes revised proposed Technical Specifications to address NRC comments regarding Action I.3. The revision to the proposed Technical Specification reflects that an extended period of operation without automatic trip capability for protection against instability events is not justified. Consequently, the proposed Technical Specifications were revised to address the use of an Automated BSP as part of the standard DSS-CD equipment.

NRC RAI 6

On page 1 of 58, GE response should be elaborated especially to include the review status and brief content of the review.

GE Response

The referenced response refers to GE Letter MFN 04-001 dated January 23, 2004. The referenced response contains GE's commitment to provide a Licensing Topical Report (LTR) documenting the qualification of TRACG for DSS-CD stability application. The LTR, NEDE-33147P, *DSS-CD TRACG Application*, was issued in GE Letter, MFN 04-019, dated February 23, 2004.

The TRACG code is used to confirm the Minimum Critical Power Ratio (MCPR) margin during reasonably limiting instability event simulations for DSS-CD applications. LTR NEDE-33147P justifies the use of TRACG for modeling instabilities in the DSS-CD process.

Many plant-specific issues can affect the CPR margins. As one example, Section 3.3.1.9 of the DSS-CD LTR states [[

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Therefore, each plant-specific application for DSS-CD will include a comparison of the resulting margins to the SLMCPR and the margins presented in the DSS-CD LTR.

[Note: This is an updated response. The response to this RAI was originally submitted in GE Letter MFN-05-148 [Ref. 15] and later revised in GE letter MFN 06-105 [Ref 16].

NRC RAI 7

On page 2 of 58, GEXL 14 Correlation for GE14 Fuel, NEDC-32851P, Revision 2 should be docketed.

GE Response

The GEXL Correlation for GE 14 fuel was submitted in GNF Letter, FLN-2001-018, dated September 25, 2001.

NRC RAI 8
On page 4 of 58, Table 3.5-2 should be included in this response.

GE Response
The referenced RAI response refers to Table 3.5-2, but the table was not included in the response. For completeness, the table will be incorporated into the RAI response when the RAIs are included in the approved version of the DSS-CD LTR.

NRC RAI 9
On page 26 of 58, GE Response should be elaborated to include a brief status report.

GE Response
The subject response refers to GE Letter, MFN 03-016, dated March 11, 2003, which transmitted the following to the NRC:

1. BWR/4 - Brunswick files
   - Compact disk containing Brunswick TRACG Analysis Inputs for DSS-CD Application
2. Fuel Files for TRACG ATWS Instability Analysis
   - Compact disk containing fuel files for TRACG ATWS Instability Analsis
3. COLPS Channel Group - Revision 1
   - Process for the COLPS Channel Grouping Calculations for ODYSY

NRC RAI 10

On page 27 of 58, GE Response should be elaborated to include the content and review status.

GE Response

The subject response refers to GE Letter, MFN 03-118, dated October 31, 2003. That letter transmitted information on the PANACEA Harmonic calculation describing the approach used to generate the harmonic modes of the neutron flux distributions.

NRC RAI 11
On page 34 of 58, GE Response should be elaborated to include the content.

GE Response
The response to the RAI was based on the then current Revision 3 of the DSS-CD LTR. The LTR has been revised and is currently at Revision 5. In Revision 4 of the LTR, Table 7-2 was added to address item a of the RAI and Section 7.3.1 was added to address items b, c, and d of the RAI. For completeness, the RAI response on page 34 of 58 will be updated when the RAIs are included in the approved version of the DSS-CD LTR to reflect the changes made in Revision 4.

NRC RAI Regarding Uncertainties

Explain the relationship between the [[ ]] and the [[ ]] in the oscillation component discussed in Section 4.4.1.2.

GE Response:

The [[ ]] is described on Pages 4-18 and 4-19 of Reference 1. The [[ ]]

The [[ ]] is discussed on Pages 4-16 through 4-18 of Reference 1. [[ ]] or licensing basis.

Consequently, the [[ ]] has no relationship to the [[ ]]

References:

1. NEDC-33075P, Revision 5, Licensing Topical Report, "General Electric Boiling Water Reactor Detect and Suppress Solution – Confirmation Density," November 2005.

2. NEDE-32906P-A, Revision 1, Licensing Topical Report, "TRACG Application for Anticipated Operational Occurrences (AOO) Transient Analyses," April 2003 (Issued January 2006).

ENCLOSURE 3

MFN 08-012

Affidavit

GE Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, Richard E. Kingston state as follows:

(1) I am Vice President, Methods Licensing, Regulatory Affairs, GE Hitachi Nuclear Energy Americas LLC ("GEH"), 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 GEH proprietary report NEDC-33075P-A, General Electric Boiling Water Reactor Detect and Suppress Solution - Confirmation Density, Revision 6, Class III (GEH Proprietary Information), dated January 2008. The GEH text proprietary information is identified by a double underline inside double square brackets. [[This sentence is an example.{3}]] Proprietary figures and large equation objects are identified with double square brackets before and after the object. In each case, the superscript notation{3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination. Note that the GEH proprietary information in the NRC's Final Safety Evaluation, which is enclosed in NEDE-33075P-A, Rev. 6, is identified with single square brackets and a bold font. **[This sentence is an example.]**

(3) In making this application for withholding of proprietary information of which it is the owner, GEH 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), and 2.390(a)(4) for "trade secrets" (Exemption 4). The material for which exemption from disclosure is here sought 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 aspects of past, present, or future General Electric customer-funded development plans and programs, resulting in potential products to General Electric;

d. 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 paragraphs (4)a. and (4)b. above.

(5) To address 10 CFR 2.390 (b) (4), the information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GEH, 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 GEH, 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 GEH 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 GEH 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 detailed results of analytical models, methods and processes, including computer codes, which GEH has developed, and applied to perform stability evaluations using the detection and suppression capability of the confirmation density algorithm for the BWR.

The development of the detection and suppression capability of the confirmation density algorithm for the BWR was achieved at a significant cost, in excess of ¼ million dollars, to GEH.

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 GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH'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 GEH.

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.

GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH 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 GEH 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 GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing these very valuable analytical tools.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Executed on this 3rd day of January 2008

Richard E. Kingston

Richard E. Kingston
GE Hitachi Nuclear Energy Americas LLC