APPENDIX 15A

PLANT NUCLEAR SAFETY OPERATIONAL ANALYSIS (NSOA)

(A System Level/Qualitative Type Plant FMEA)

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PLANT NUCLEAR SAFETY OPERATIONAL ANALYSIS (NSOA)
(A System-Level/Qualitative-Type Plant FMEA)

15A.1 OBJECTIVES

The five objectives of the NSOA are discussed in the following sections.

15A.1.1 Essential Protective Sequences

Identify and demonstrate that essential protection sequences needed to accommodate the plant normal operations, anticipated and abnormal transients, operations, and design basis accidents (DBA) are available and adequate. In addition, each event considered in the plant safety analysis (Chapter 15) is further examined and analyzed. Specific essential protective sequences are identified. The appropriate sequence is discussed for all boiling water reactor (BWR) operating modes.

15A.1.2 Design Basis Adequacy

Identify and demonstrate that the safety design basis of the various structures, systems, or components needed to satisfy the plant essential protection sequences are appropriate, available, and adequate. Each protective sequence identifies the specific structures, systems, or components performing safety or power generation functions. The interrelationships between primary systems and secondary (or auxiliary) equipment in providing these functions are shown. The individual design bases (identified throughout the Final Safety Analysis Report (FSAR) for each structure, system, or component) are brought together by the analysis in this section. In addition to the individual equipment design basis analysis, the plant-wide design bases are examined and presented here.

15A.1.3 System-Level/Qualitative-Type Failure Modes and Effects Analysis

Identify a system-level/qualitative-type failure modes and effects analysis (FMEA) of essential protective sequences to show compliance with the single active component failure (SACF) or single operator error (SOE) criteria. Each protective sequence entry is evaluated relative to SACF or SOE criteria. Safety classification aspects and interrelationships between systems are also considered.

15A.1.4 NSOA Criteria Relative to Plant Safety Analysis

Identify the systems, equipment, or components' operational conditions and requirements essential to satisfy the nuclear safety operational criteria utilized in the Chapter 15 plant events.

15A.1.5 Technical Specification Operational Basis

Establish the limiting conditions of operations (LCO), testing, and surveillance bases relative to plant Technical Specification.

15A.2 APPROACH TO OPERATIONAL NUCLEAR SAFETY

15A.2.1 General Philosophy

The specified measures of safety used in this analysis are referred to as unacceptable consequences. They are analytically determinable limits on the consequences of different classifications of plant events. The NSOA is thus an "event-consequence" oriented evaluation. Refer to Figure 15A-1 for a description of the systematic process by which these unacceptable results are converted into safety requirements.

15A.2.2 Specific Philosophy

The following guidelines are utilized to develop the NSOA.

<u>Scope and Classification of Plant Events</u>

<u>Normal (Planned) Operations</u> Normal operations that are under planned conditions in the absence of significant abnormalities. Operations subsequent to an incident (transient, accident, or special event) are not considered planned operations until the procedures being followed or equipment being used are identical to those used during any one of the defined planned operations. Specific events are described further in Table 15A-1.

<u>Anticipated (Expected) Operational Transients</u> Anticipated operational transients are deviations from normal conditions that are expected to occur with moderate frequency, and as such the design should include capability to withstand the conditions without operational impairment. Included are incidents that result from a SOE, control malfunction, and others (Table 15A-2).

<u>Abnormal (Unexpected) Operational Transients</u> Abnormal operational transients are deviations from normal conditions that occur with infrequent frequency. The design should include a capability to withstand these conditions without operational impairment. Table 15A-3 describes events included within this classification.

<u>Design Basis (Postulated) Accidents</u> A DBA is a hypothesized accident, the characteristics and consequences of which are utilized in the design of those systems and components pertinent to the preservation of radioactive material barriers and the restriction of radioactive material release from the barriers. The potential radiation exposures resulting from a DBA are

greater than for any similar accident postulated from the same general accident assumptions. Specific events are described in Table 15A-4.

Special (Hypothetical) Events Special events are postulated to demonstrate some special capability of the plant in accordance with Nuclear Regulatory Commission (NRC) requirements. For analyzed events within this classification, see Table 15A-5.

Safety and Power Generation Aspects

Safety functions include:

1. The accommodation of abnormal operational transients and postulated DBAs.

2. Maintenance of primary containment integrity.

3. Assurance of emergency core cooling system (ECCS) operability.

4. Continuance of reactor coolant pressure boundary (RCPB) integrity.

Safety classified aspects are related to 10CFR100 dose limits, infrequent and low-probability occurrences, SACF criteria, worst-case operating conditions and initial assumptions, automatic (less than 10 min) corrective action, significant unacceptable dose and environmental effects, and the involvement of other coincident (mechanistic or nonmechanistic) plant and environmental situations.

Power generation classified considerations are related to continued plant power generation operation, equipment operational matters, component availability aspects, and long-term offsite public effects.

Power generation functions include:

1. Accommodation of planned operations and anticipated operational transients.

2. Minimization of radiological releases to appropriate levels.

3. Assurance of safe and orderly reactor shutdown, and/or return to power generation operation.

4. Continuance of plant equipment design conditions to ensure long-term reliable operation.

Power generation is related to 10CFR20 and 10CFR50 Appendix I dose limits, moderate- and high-probability occurrences, nominal operating conditions and initial assumptions, allowable immediate operator manual actions, and insignificant unacceptable dose and environmental effects.

Frequency of Events

Consideration of the frequency of the initial (or initiating) event is reasonably straightforward. Added considerations (e.g., further failures or Operator errors) influence the classification grouping. The events in this appendix are initially grouped according to initiating frequency occurrence. The imposition of further failures necessitates further classification to a lower frequency category.

The introduction of SACF or SOE into the examination of planned operation, anticipated operational transients, or abnormal operational transient evaluations has not been previously considered a design basis or evaluation prerequisite. It is provided and included here to demonstrate the plant's capability to accommodate this requirement.

Conservative Analysis - Margins

The unacceptable consequences established in this appendix relative to the public health and safety aspects are in strict and conservative conformance to regulatory requirements.

Safety Function Definition

Essential protective sequences shown for an event in this appendix list the minimum structures and systems required to be available to satisfy the SACF or SOE evaluation aspects of the event. Protective "success paths" other than those shown with the event exist in some cases.

Not all the events involve the same natural, environmental, or plant condition assumptions. For example, loss-of-coolant accident (LOCA) and safe shutdown earthquake (SSE) are associated with Event 44. In Event 40, control rod drop accident (CRDA) is not assumed to be associated with any SSE or operating basis earthquake (OBE) occurrence. Therefore, seismic safety function requirements are not considered for Event 40. Some of the safety function equipment associated with the Event 40 protective sequence are also capable of handling more limiting events, such as Event 44.

The primary containment may perform a safety function for some event (when uncontained radiological release would be unacceptable) but for other events it may not be applicable (e.g., during refueling). The requirement to maintain the primary containment in post-accident recovery is only needed to limit doses to less than 10CFR100. After radiological sources are depleted with time, the further use of primary containment is unnecessary. Thus, the "time domain" and "need for" aspects of a function should be and are taken into account and considered when evaluating the events in this appendix.

The operation of engineered safety feature (ESF) equipment for normal operational events should not be misunderstood to mean that ESF equipment requirements apply to this event category.

Likewise, the interpretation of the use of ESF-SACF capable systems for anticipated operational transient protective sequences should not imply that these equipment requirements (seismic, redundancy, diversity, testable, IEEE) are required for anticipated operational transients.

Envelope and Actual Event Analysis

Study of the actual plant occurrences, their frequency, and their actual impact are reflected in their categorization in this appendix. This places the plant safety evaluations into a better perspective by focusing attention on the envelope analysis.

15A.2.2.1 Consistency of the Analysis

Figure 15A-2 illustrates three inconsistencies. Panel A shows the possible inconsistency resulting from operational requirements being placed on separated levels of protection for one event. If the second and sixth levels of protection are important enough to warrant operational requirements, then so are the third, fourth, and fifth levels. Panel B shows the possible inconsistency resulting from operational requirements being arbitrarily placed on some action thought to be important to safety. In the case shown, scram represents different protection levels for two similar events in one category; if the fourth level of protection for Event B is important enough to warrant an operational requirement, then so is the fourth level for Event A. Thus, to simply place operational requirements on all equipment needed for some action (scram, isolation, etc.) could be inconsistent and unreasonable if different protection levels are represented. Panel C shows the possible inconsistency resulting from operational requirements being placed on some arbitrary level of protection for any and all postulated events. Here the inconsistency is not recognizing and accounting for different event categories based on cause or expected frequency of occurrence.

Inconsistencies of the types illustrated on Figure 15A-2 are avoided in the NSOA by directing the analysis to event-consequences oriented aspects. Analytical inconsistencies are avoided by treating all the events of a category under the same set of functional rules applying another set of functional rules to another category, and by having a consistent set of rules between categories. Thus, it is valid to compare the results of the analyses of the events in any one category and invalid to compare events of different categories, and thus different rules, to the other category. An example of this is the different rules (limits, assumptions, etc.) of accidents compared to anticipated transients.

15A.2.3 Comprehensiveness of the Analysis

The analysis must be sufficiently comprehensive in method that: 1) all plant hardware is considered, and 2) the full range of plant operating conditions are considered. The tendency to be preoccupied with "worst cases" (those that appear to give the most severe consequences) is recognized; however, the protection sequences essential to lesser cases may be different (more or less restrictive) from the worst-case sequence. To assure that operational and design basis requirements are defined and appropriate for all equipment essential to attaining acceptable consequences, all essential protection sequences must be identified for each of the plant safety events examinations. Only in this way is a comprehensive level of safety attained. Thus, the NSOA is also protection-sequence oriented to achieve comprehensiveness.

15A.2.4 Systematic Approach of the Analysis

In summary, the systematic method utilized in this analysis contributes to both the consistency and comprehensiveness of the analysis mentioned above. The desired characteristics representative of a systematic approach to selecting BWR operational requirements are as follows:

1. Specify measures of safety-unacceptable consequences.

2. Consider all normal operations.

3. Systematic event selection.

4. Common treatment analysis of all events of any one type.

5. Systematic identification of plant actions and systems essential to avoiding unacceptable consequences.

6. Emergence of operational requirements and limits from system analysis.

Figure 15A-1 illustrates the systematic process by which the operational and design basis nuclear safety requirements and Technical Specifications are derived. The process involves the evaluation of carefully selected plant events relative to the unacceptable consequences (specified measures of safety). Those limits, actions, systems, and component levels found to be essential to achieving acceptable consequences are the subjects of operational requirements.

Figure 15A-3 summarizes the systematic treatment of the appendix analysis.

15A.2.5 Relationship of NSOA to Safety Analyses of Chapter 15

One of the main objectives of the operational analysis is to identify all essential protection sequences and to establish the detailed equipment conditions essential to satisfying the nuclear safety operational criteria. The spectrum of events examined in Chapter 15 represents a complete set of plant safety considerations. The main objective of the earlier analyses of Chapter 15 is, of course, to provide detailed worst-case (limiting or envelope) analyses of the plant events. The worst cases are correspondingly analyzed and treated likewise in this appendix but in light of frequency of occurrence, unacceptable consequences, and assumption categories, etc.

Tables 15A-1 through 15A-5 provide cross-correlation between the NSOA event, its protection sequence diagram, and its safety evaluation in Chapter 15.

15A.2.6 Relationship Between NSOA and Operational Requirements, Technical Specifications, Design Basis, and SACF Aspects

By definition, an operational requirement is a requirement or restriction (limit) on either the value of a plant variable or the operability condition associated with a plant system. Such requirements must be observed during all modes of plant operation (not just at full power) to assure that the plant is operated safely (to avoid the unacceptable results). There are two kinds of operational requirements for plant hardware:

1. Limiting condition for operation: the required condition for a system while the reactor is operating in a specified state.

2. Surveillance requirements: the nature and frequency of tests required to assure that the system is capable of performing its essential functions.

Operational requirements are systematically selected for one of two basic reasons:

1. To assure that unacceptable consequences are prevented or mitigated following specified plant events by examining and challenging the system design.

2. To assure the consequences of a transient or accident are acceptable with the existence of a SACF or SOE criteria.

The individual structures and systems that perform a safety function are required to do so under design basis conditions including environmental consideration and under SACF assumptions. The NSOA confirms the previous examination of the individual equipment (Section 15.0.3) requirement conformance analyses.

15A.2.7 Unacceptable Consequences Criteria

Tables 15A-6 through 15A-10 identify the unacceptable consequences associated with different event categories. In order to prevent or mitigate them, they are recognized as the major bases for identifying system operational requirements as well as the bases for all other safety analyses versus criteria throughout the FSAR.

15A.2.8 General Nuclear Safety Operational Criteria

The following general nuclear safety operational criteria are used to select operational requirements:

Applicability	Nuclear Safety Operational Criteria
Planned operation, anticipated, abnormal operational transients, DBAs, and additional special plant capability events.	The plant shall be operated so as to avoid unacceptable consequences.
Anticipated and abnormal operational transients and DBAs.	The plant shall be operated in such a way that no SACF can prevent the safety actions essential to avoiding the unacceptable consequences associated with anticipated or abnormal operational transients or DBAs. However, this requirement is not applicable during structure, system, or component repair if the availability of the safety action is maintained either by restricting the allowable repair time or by more frequently testing a redundant structure, system, or component.

The unacceptable consequences associated with the different categories of plant operation and events are dictated by:

1. Probability of occurrence.

2. Allowable limits (per the probability) - related to radiological, structural, environmental, etc., aspects.

3. Coincidence of other related or unrelated disturbances.

4. Time domain of event and consequences consideration.

15A.3 METHOD OF ANALYSIS

15A.3.1 General Approach

The NSOA is performed on the plant as designed. The end products of the analysis are the nuclear safety operational requirements and the restrictions on plant hardware and its operation that must be observed: 1) to satisfy the nuclear safety operational criteria, and 2) to show compliance of the plant safety and power generation systems with plant-wide requirements. Figure 15A-1 shows the process used in the analysis. The following inputs are required for the analysis of specific plant events:

1. Unacceptable consequences criterion (Section 15A.2.7).
2. General nuclear safety operational criteria (Section 15A.2.8).
3. Definition of BWR operating states (Section 15A.3.2).
4. Selection of events for analysis (Section 15A.3.3).
5. Rules for event analysis (Section 15A.3.5).

With this information, each selected event can be evaluated to determine systematically the actions, systems, and limits essential to avoiding the defined unacceptable consequences. The essential plant components and limits so identified are then considered to be in agreement with and subject to nuclear operational design basis requirements and Technical Specification restrictions.

15A.3.2 BWR Operating States

Four BWR operating states in which the reactor can exist are defined in Section 15A.6.2.4 and summarized in Table 15A-11. The main objective in selecting operating states is to divide the BWR operating spectrum into sets of initial conditions to facilitate consideration of various events in each state.

Each operating state includes a wide spectrum of values for important plant parameters. Within each state, these parameters are considered over their entire range to determine the limits on their values necessary to satisfy the nuclear safety operational criteria. Such limitations are presented in the sections of the FSAR that describe the systems associated with the parameter limit. The plant parameters to be considered in this manner include the following:

1. Reactor coolant temperature.
2. Reactor vessel water level.

3. Reactor vessel pressure.

4. Reactor vessel water quality.

5. Reactor coolant recirculation flow rate.

6. Reactor power level (thermal and neutron flux).

7. Core neutron flux distribution.

8. Feedwater temperature.

9. Primary containment temperature and pressure.

10. Suppression pool water temperature and level.

15A.3.3 Selection of Events for Analysis

15A.3.3.1 Normal Operation

Operations subsequent to an incident (transient, accident, or additional plant capability event) are not considered planned operations until the actions taken or equipment used in the plant are identical to those that would be used had the incident not occurred. As defined, the planned operations can be considered as a chronological sequence: refueling outage → achieving criticality → heatup → power operation → achieving shutdown → cooldown → refueling outage.

For the analysis in this appendix, the normal operations events are defined as follows:

Refueling Outage Includes all the planned operations associated with a normal refueling outage except for certain tests in which the reactor is taken critical and returned to the shutdown condition. The following planned operations are included in refueling outage:

1. Planned, physical movement of core components (fuel, control rods, etc.).

2. Refueling test operations (except criticality and shutdown margin tests).

3. Planned maintenance.

4. Required inspection.

Achieving Criticality Includes all the plant actions normally accomplished in bringing the plant from a condition in which all control rods are fully inserted to a condition in which nuclear criticality is achieved and maintained.

<u>Heatup</u> Begins when achieving criticality ends and includes all plant actions normally accomplished in approaching nuclear system rated temperature and pressure by using nuclear power (reactor critical). Heatup extends through warmup and synchronization of the main turbine generator.

<u>Power Operation</u> Begins when heatup ends and includes continued plant operation at power levels in excess of heatup power.

<u>Achieving Shutdown</u> Begins when the main generator is unloaded and includes all plant actions normally accomplished in achieving nuclear shutdown (more than one rod subcritical) following power operation.

<u>Cooldown</u> Begins when achieving nuclear shutdown ends and includes all plant actions normal to the continued removal of decay heat and the reduction of reactor pressure vessel (RPV) temperature and pressure.

The exact point at which some of the planned operations end and others begin cannot be precisely determined. It is shown later that such precision is not required, since the protection requirements are adequately defined in passing from one state to the next. Dependence of several planned operations on the one rod subcritical condition provides an exact point on either side of which protection (especially scram) requirements differ. Thus, where a precise boundary between planned operations is needed, the definitions provide the needed precision.

Together, the BWR operating states and the planned operations define the full spectrum of conditions from which transients, accidents, and special events are initiated. The BWR operating states define only the physical condition (pressure, temperature, etc.) of the reactor; the planned operations define the condition of the plant. The separation of physical conditions from the operation being performed is deliberate and facilitates careful consideration of all possible initial conditions from which incidents may occur.

15A.3.3.2 Anticipated Operational Transients

To select anticipated operational transients, eight nuclear system parameter variations are considered as potential initiating causes of threats to the fuel and the RCPB. The parameter variations are as follows:

1. Reactor coolant pressure increase.

2. Reactor coolant water (moderator) temperature decrease.

3. Control rod withdrawal.

4. Reactor coolant inventory decrease.

5. Reactor coolant flow decrease.

6. Reactor coolant flow increase.

7. Reactor coolant temperature increase.

8. Reactor coolant inventory increase.

These parameter variations, if uncontrolled, could result in damage to the reactor fuel or RCPB, or both. A nuclear system pressure increase threatens to rupture the RCPB from internal pressure. A pressure increase also collapses voids in the moderator, causing an insertion of positive reactivity that threatens fuel damage as a result of overheating. A reactor coolant temperature decrease results in an insertion of positive reactivity as density increases. This could lead to fuel overheating. Positive reactivity insertions are possible from causes other than nuclear system pressure or moderator temperature changes. Such reactivity insertions threaten fuel damage caused by overheating. Both a reactor coolant inventory decrease and a reduction in coolant flow through the core threaten the integrity of the fuel. An increase in coolant flow through the core reduces the void content of the moderator, and results in an insertion of positive reactivity. Core coolant temperature increase threatens the integrity of the fuel; such a variation could be the result of a heat exchanger malfunction during operation in the shutdown cooling mode. An excess of coolant inventory could be the result of malfunctioning water level control equipment; such a malfunction can result in a turbine trip, which causes an expected increase in nuclear system pressure and power.

Anticipated operational transients are defined as transients resulting from a SACF or SOE that can be reasonably expected (moderate frequency of occurrence of once per day to once per 20 yr) during any mode of plant operation. Examples of single operational failures or operator errors in this frequency range are:

1. Opening or closing any single valve (a check valve is not assumed to close against normal flow).

2. Starting or stopping any single component.

3. Malfunction or maloperation of any single control device.

4. Any single electrical failure.

5. Any single Operator error.

An Operator error is defined as an active deviation from nuclear plant standard operating practices. A SOE is the set of actions that is a direct consequence of a single reasonably expected erroneous decision. The set of actions is limited as follows:

1. Those actions that could be performed by only one person.

2. Those actions that would have constituted a correct procedure had the initial decision been correct.

3. Those actions that are subsequent to the initial Operator error and that affect the designed operation of the plant, but are not necessarily directly related to the Operator error.

Examples of SOEs are as follows:

1. An increase in power above the established flow control power limits by control rod withdrawal in the specified sequences.

2. The selection and complete withdrawal of a single control rod out of sequence.

3. An incorrect calibration of an average power range monitor (APRM).

4. Manual isolation of the main steam lines caused by Operator misinterpretation of an alarm or indication.

The various types of SOE or SACF are applied to various plant systems with a consideration for a variety of plant conditions to discover events directly resulting in an undesired parameter variation. Once discovered, each event is evaluated for the threat it poses to the integrity of the radioactive material barriers.

15A.3.3.3 Abnormal Operational Transients

To select abnormal operational transients, eight nuclear system parameter variations are considered as potential initiating causes of gross core-wide fuel failures and threats to the RCPB. The parameter variations are the same as in Section 15A.3.3.2.

The eight parameter variations include all effects within the nuclear system caused by abnormal operational transients that threaten gross core-wide reactor fuel integrity or seriously affect the RCPB. Variation of any one parameter may cause a change in another listed parameter; however, for analysis purposes, threats to barrier integrity are evaluated by groups according to the parameter variation originating the threat.

Abnormal operational transients are defined as infrequent incidents resulting from single or multiple equipment failures and/or single or multiple Operator errors that are not reasonably expected (spanning one event in 20 yr to one in 100 yr) during any mode of plant operation. Examples of single or multiple operational failures and/or single or multiple Operator errors are:

1. Failure of major power generation equipment components.
2. Multiple electrical failures.
3. Multiple Operator errors.
4. Combinations of an equipment failure and an Operator error.

Operator error is defined as an active deviation from nuclear plant standard operating practices. A multiple Operator error is the set of actions that is a direct consequence of several unexpected erroneous decisions.

Examples of multiple Operator errors are as follows:

1. Inadvertent loading and operating a fuel assembly in an improper position.
2. The inadvertent withdrawal of a control rod with fuel in the control cell during refueling operations.

The various types of single errors and/or single malfunctions are applied to various plant systems with a consideration for a variety of plant conditions to discover events directly resulting in an undesired parameter variation. Once discovered, each event is evaluated for the threat it poses to the integrity of the various radioactive material barriers.

15A.3.3.4 Design Basis Accidents

Accidents are defined as hypothesized events that affect the radioactive material barriers and are not expected during plant operations. These are plant events, equipment failures, and combinations of initial conditions that are of extremely low frequency with a probability of one in 100 to 10,000 yr. The postulated accident types considered are as follows:

1. Mechanical failure of a single component leading to the release of radioactive material from one or more barriers. The components referred to here are not those that act as radioactive material barriers. Examples of mechanical failure are breakage of the coupling between a control rod drive (CRD) and the control rod.
2. Arbitrary rupture of any single pipe up to and including complete severance of the largest pipe in the RCPB. This kind of accident is considered only under conditions in which the nuclear system is pressurized.

For purposes of analysis, accidents are categorized as those events that result in releasing radioactive material:

1. From the fuel with the RCPB and reactor building initially intact (Event 40).

2. Directly to the primary containment (Event 42).

3. Directly to the reactor or turbine buildings with the primary containment initially intact (Events 40, 43, 44, 45, 50).

4. Directly to the reactor building with the primary containment not intact (Events 41, 50).

5. Directly to the reactor building (Events 41, 50).

6. Directly to the turbine building (Events 46, 47).

7. Directly to the environs (Events 48, 49).

The effects of various accident types are investigated, with consideration for the full spectrum of plant conditions, to examine events that result in the release of radioactive material.

15A.3.3.5 Special Events

A number of additional events are evaluated to demonstrate plant capabilities relative to special nuclear safety criteria. These special events involve extremely low probability occurrence situations. As an example, the adequacy of the redundant reactivity control system (RRCS) is demonstrated by evaluating the special event, reactor shutdown without control rods. Another similar example, the capability to perform a safe shutdown from outside the main control room, is demonstrated by evaluating the special event, reactor shutdown from outside the main control room.

15A.3.4 Applicability of Events to Operating States

The first step in performing an operational analysis for a given incident (transient, accident, or special event) is to determine in which operating states the incident can occur. An incident is considered applicable within an operating state if the incident can be initiated from the physical conditions that characterize the operating state. Applicability of the normal operations to the operating states follows from the definitions of planned operations. A planned operation is considered applicable within an operating state if the planned operation can be conducted when the reactor exists under the physical conditions defining the operating state.

15A.3.5 Guidelines for Event Analysis

The following functional guidelines are followed in performing SACF, operational, and design basis analyses for the various plant events:

1. An action, system, or limit shall be considered essential only if it is essential to avoiding an unacceptable result or satisfying the nuclear safety operational criteria.

2. The full range of initial conditions (as defined in Section 15A.3.5, Item 3) shall be considered for each event analyzed so that all essential protection sequences are identified. Consideration is not limited to worst cases because lesser cases sometimes may require more restrictive actions or systems different from those of the worst cases.

3. The initial conditions for transients, accidents, and additional plant capability events shall be limited to conditions that would exist during planned operations in the applicable operating state.

4. For normal operations, consideration shall be made only for actions, limits, and systems essential to avoiding the unacceptable consequences during operation in that state (as opposed to transients, accidents, and additional plant capability events, which are followed through to completion). Normal operations are treated differently from other events because the transfer from one state to another during planned operations is deliberate. For events other than normal operations, the transfer from one state to another may be unavoidable.

5. Limits shall be derived only for those essential parameters that are continuously available for monitoring. Parameter limits associated with the required performance of an essential system are considered to be included in the requirement for the operability of the system. Limits on frequently monitored process parameters are called envelope limits, and limits on parameters associated with the operability of a safety system are called operability limits. Systems associated with the control of the envelope parameters are considered nonessential if it is possible to place the plant in a safe condition without using the system.

6. For transients, accidents, and special events, consideration shall be made for the entire duration of the event and aftereffects until some planned operation is resumed. Normal operation is considered resumed

when the procedures being followed or equipment being used are identical to those used during any one of the defined planned operations. Where extended core cooling is an immediate integral part of the event, it is included in the protection sequence. Where it may be an eventual part of the event it is not directly added, but can be implied to be available.

7. Credit for Operator action shall be taken on a case-by-case basis depending on the conditions that would exist at the time Operator action would be required. Because transients, accidents, and special events are considered through the entire duration of the event until normal operation is resumed, manual operation of certain systems is sometimes required following the more rapid or automatic portions of the event. Credit for Operator action is taken only when the Operator can reasonably be expected to accomplish the required action under the existing conditions.

8. For transients, accidents, and special events, only those actions, limits, and systems shall be considered essential for which there arises a unique requirement as a result of the event. For instance, if a system that was operating prior to the event (during planned operation) is to be employed in the same manner following the event, and if the event did not affect the operation of the system, then the system would not appear on the protection sequence diagram.

9. The operational analyses shall identify all the support or auxiliary systems essential to the functioning of the safety-related systems. Safety system auxiliaries whose failure results in safe failure of the safety-related systems shall be considered nonessential.

10. A system or action that plays a unique role in the response to a transient, accident, or special event shall be considered essential unless the effects of the system or action are not included in the detailed analysis of the event.

15A.3.6 Steps in an Operational Analysis

All information needed to perform an operational analysis for each plant event has been presented (Figure 15A-1). The procedure followed in performing an operational analysis for a given event (selected according to the event selection criteria) is as follows:

1. Determine the BWR operating states in which the event is applicable.

2. Identify all the essential protection sequences (safety actions and safety-related systems) for the event in each applicable operating state.

3. Identify all the safety system auxiliaries essential to the functioning of the safety-related systems.

The preceding three steps are performed in Section 15A.6.

To derive the operational requirements and Technical Specifications for the individual components of a system included in any essential protection sequence, the following steps are taken:

1. Identify all the essential actions within the system (intrasystem actions) necessary for the system to function to the degree necessary to avoid the unacceptable consequences.

2. Identify the minimum hardware conditions necessary for the system to accomplish the minimum intrasystem actions.

3. If the single-failure criterion applies, identify the additional hardware conditions necessary to achieve the plant safety actions (scram, pressure relief, isolation, cooling, etc.), in spite of single failures. This step gives the nuclear safety operational requirements for the plant components so identified.

4. Identify surveillance requirements and allowable repair times for the essential plant hardware (Section 15A.5.2).

5. Simplify the operational requirements determined in Steps 3 and 4 so that technical specifications may be obtained that encompass the true operational requirements and are easily used by plant operations and management personnel.

15A.4 DISPLAY OF OPERATIONAL ANALYSIS RESULTS

15A.4.1 General

To fully identify and establish the requirements, restrictions, and limitations that must be observed during plant operation, plant systems and components must be related to the needs for their actions in satisfying the nuclear safety operational criteria. This appendix displays these relationships in a series of block diagrams.

Tables 15A-1 through 15A-5 and 15A-11 indicate the operating states applicable to each event. For each event, a block diagram is present showing the conditions and systems required to achieve each essential safety action. The block diagrams show only those systems necessary to provide the safety actions so that the nuclear safety operational and design basis criteria are satisfied. The total plant capability to provide a safety action is generally not shown, only the minimum capability essential to satisfying the operational criteria. It is very important to understand that only enough protective equipment is cited in the diagram to provide the necessary action. Many events can utilize more paths to success than are shown. These operational analyses involve the minimum equipment needed to prevent or avert an unacceptable consequence. Thus, the diagrams depict all essential protection sequences for each event with the least amount of protective equipment needed.

Once all of these protection sequences are identified in block diagram form, system requirements are derived by considering all events in which the particular system is employed. The analysis considers the following conceptual aspects:

1. BWR operating state.

2. Types of operations or events that are possible within the operating state.

3. Relationships of certain safety actions to the unacceptable consequences and to specific types of operations and events.

4. Relationships of certain systems to safety actions and to specific types of operations and events.

5. Supporting or auxiliary systems essential to the operation of the safety-related systems.

6. Functional redundancy (The single-failure criterion applied at the safety action level. This is, in effect, a qualitative, system level, FMEA-type analysis.).

Each block in the sequence diagrams represents a finding of essentiality for the safety action, system, or limit under consideration. Essentiality in this context means that the safety action, system, or limit is needed to satisfy the nuclear safety operational criteria. Essentiality is determined through an analysis in which the safety action, system, or limit being considered is completely disregarded in the analyses of the applicable operations or events. If the nuclear safety operational criteria are satisfied without the safety action, system, or limit, then the safety action, system, or limit is not essential, and no operational nuclear safety requirement would be indicated. When disregarding a safety action, system, or limit results in violating one or more nuclear safety operational criteria, the safety action, system, or limit is considered essential, and the resulting operational nuclear safety requirements can be related to specific criteria and unacceptable consequences.

15A.4.2 Protection Sequence and Safety System Auxiliary Diagrams

Block diagrams illustrate essential protection sequences for each event requiring unique safety actions. These protection sequence diagrams show only the required front-line safety systems. The format and conventions used for these diagrams are shown on Figure 15A-4.

The auxiliary systems essential to the correct functioning of safety-related systems are shown on safety system auxiliary diagrams. The format used for these diagrams is shown on Figure 15A-5. The diagram indicates that auxiliary systems A, B, and C are required for proper operation of safety-related system X.

Total plant requirements for an auxiliary system or the relationships of a particular auxiliary system to all other safety systems within an operating state are shown on the commonality of auxiliary diagrams. The format used for these diagrams is shown on Figure 15A-6. The convention employed on Figure 15A-6 indicates that auxiliary system A is required:

1. To be single-failure proof relative to system γ in State A-events X, Y; State B-events X, Y; State C-events X, Y, Z; State D-events X, Y, Z.

2. To be single-failure proof relative to the parallel combination of systems α and β in State A-events U, V, W; State B-events V, W; State C-events U, V, W, X; State D-events U, V, W, X.

3. To be single-failure proof relative to the parallel combination of system π and system $\in$ in series with the parallel combination of systems ξ and Ψ in State C-events Y, W; State D-events Y, W, Z. As noted, system $\in$ is part of the combination but does not require auxiliary system A for its proper operation.

4. For system δ in State B-events Q, R; State D-events Q, R, S.

With these three types of diagrams, it is possible to determine for each system the detailed functional requirements and conditions to be observed regarding system hardware in each operating state. The detailed conditions to be observed regarding system hardware include such nuclear safety operational requirements as test frequencies and the number of components that must be operable.

15A.5 BASES FOR SELECTING SURVEILLANCE TEST FREQUENCIES

After the essential nuclear safety systems and engineered safeguards have been identified by applying the nuclear safety operational criteria, surveillance requirements are selected for these systems. In this selection process, the various systems are considered in terms of relative availability, test capability, plant conditions necessary for testing, and engineering experience with the system type.

Surveillance test frequencies are included in the NRC-approved Station Technical Specifications.

The intent in selecting surveillance test frequencies is to balance the objective of ensuring the operability of safety systems and engineered safeguards against any reduction in reliability due to the stress or wear inherent in the testing, and against any reduction in availability due to putting the system or component in a test configuration.

This approach is similar to that endorsed by the NRC in 10CFR50.65 regarding maintenance, which states, "Adjustments shall be made where necessary to ensure that the objective of preventative (sic) failures of structures, systems, and components through maintenance is appropriately balanced against the objective of minimizing unavailability of structures, systems, and components due to monitoring or preventative maintenance."

15A.6 OPERATIONAL ANALYSES

Results of the operational analyses are discussed in the following paragraphs and displayed on Figures 15A-7 through 15A-53 and in Tables 15A-1 through 15A-5.

15A.6.1 Safety System Auxiliaries

Figures 15A-7 and 15A-8 show the safety system auxiliaries essential to the functioning of each safety-related system.

15A.6.2 Normal Operations

15A.6.2.1 General

Requirements of the normal or planned operations normally involve limits (L) on certain key process variables and restrictions (R) on certain plant equipment. The control block diagrams for each operating state (Figures 15A-9 through 15A-12) show only those controls necessary to avoid unacceptable safety consequences, 1-1 through 1-4 of Table 15A-6.

Following is a description of the planned operations (Events 1 through 6) as they pertain to each of the four operating states. The description of each operating state contains a definition of that state, a list of the planned operations that apply to that state, and a list of the safety actions that are required to avoid the unacceptable safety consequences.

15A.6.2.2 Event Definitions

Event 1 - Refueling Outage

This event is defined in Section 15A.3.3.1.

Event 2 - Achieving Criticality

This event is defined in Section 15A.3.3.1.

Event 3 - Reactor Heatup

This event is defined in Section 15A.3.3.1.

Event 4 - Power Operation

Power operation begins where heatup ends and continued plant operation at power levels in excess of heatup power or steady-state operation. It also includes plant maneuvers such as:

1. Daily electrical load reduction and recoveries.

2. Electrical grid frequency control adjustment.

3. Control rod movements.

4. Power generation surveillance testing involving:

    a. Turbine stop valve closing.

    b. Turbine control valve adjustments.

    c. Main steam isolation valve (MSIV) exercising.

Event 5 - Achieving Reactor Shutdown

This event is defined in Section 15A.3.3.1.

Event 6 - Reactor Cooldown

This event is defined in Section 15A.3.3.1.

15A.6.2.3 Required Safety Actions/Related Unacceptable Consequences

The following paragraphs describe the safety actions for planned operations. Each description includes a selection of the operating states that apply to the safety action, the plant system affected by limits or restrictions, and the unacceptable consequence that is avoided. The four operating states are defined in Section 15A.6.2.4 and summarized in Table 15A-11. The unacceptable consequences criteria are tabulated in Tables 15A-6 through 15A-10.

15A.6.2.3.1 Radioactive Material Release Control

The possibility of radioactive materials being released to the environs exists in any operating state; therefore, radioactive material release control is required in all operating states. Because of the significance of preventing excessive release of radioactive materials to the environs, this is the only safety action for which monitoring systems are explicitly shown. The radiation monitoring system (RMS) provides indication for gaseous release from the offgas vent along with other gaseous releases from ventilation. The process liquid radiation monitors are not required, because all liquid wastes are monitored by batch sampling before a controlled release. Limits are expressed on the offgas system (OFG), liquid radwaste system (LWS), and solid radwaste system so that the planned releases of radioactive materials comply with the limits given in 10CFR20, 10CFR50, and 10CFR71 (related unacceptable safety result 1-1 shown in Table 15A-6).

15A.6.2.3.2 Core Coolant Flow Rate Control

In State D (Section 15A.6.2.4), when above approximately 10 percent nuclear boiler rated (NBR) power, the core coolant flow rate must be maintained above certain minimums (i.e., limited) to maintain the integrity of the fuel cladding (1-2) and assure the validity of the plant safety analysis (1-4).

15A.6.2.3.3 Core Power Level Control

The plant safety analyses of accidental positive reactivity additions have assumed as an initial condition that the neutron source level is above a specified minimum. Because a significant positive reactivity addition can only occur when the reactor is less than one rod subcritical, the assumed minimum source level need be observed only in States B and D (Section 15A.6.2.4). The minimum source level assumed in the analyses has been related to the counts-per-second readings on the source range monitors (SRM); thus, this minimum power level limit on the fuel is expressed as a required SRM count level. Observing the limit assures validity of the plant safety analysis (1-4). Maximum core power limits are also expressed for operating States B and D to maintain fuel integrity (1-2) and remain below the maximum power levels assumed in the plant safety analysis (1-4).

15A.6.2.3.4 Core Neutron Flux Distribution Control

Core neutron flux distribution must be limited in State D, otherwise, core power peaking could result in fuel failure (1-2). Additional limits are expressed in this state, because the core neutron flux distribution must be maintained within the envelope of conditions considered by plant safety analysis (1-4).

15A.6.2.3.5 Reactor Vessel Water Level Control

In any operating state, the reactor vessel water level could, unless controlled, drop to a level that does not provide adequate core cooling; therefore, reactor vessel water level control applies to all operating states. Observation of the reactor vessel water level limits protects against fuel failure (1-2) and assures the validity of the plant safety analysis (1-4).

15A.6.2.3.6 Reactor Vessel Pressure Control

Reactor vessel pressure control is not needed in States A and B because vessel pressure cannot be increased above atmospheric pressure. In State C, a limit is expressed on the reactor vessel to assure that it is not hydrostatically tested until the temperature is above the NDT temperature plus 60°F; this prevents excessive stress (1-3). Also, in States C and D a limit is expressed on the residual heat removal (RHR) system to assure that it is not operated in the shutdown cooling mode when the reactor vessel pressure is greater than approximately 135 psig; this prevents excessive stress (1-3). In States C and D, a limit on the reactor vessel pressure is necessitated by the plant safety analysis (1-4).

15A.6.2.3.7 Nuclear System Temperature Control

In operating States C and D, a limit is expressed on the reactor vessel to prevent the reactor vessel head bolting studs from being in tension when the temperature is less than 70°F to avoid excessive stress (1-3) on the reactor vessel flange. This limit does not apply in States A and B because the head is not bolted in place during criticality tests or during refueling. In all operating states, a limit is expressed on the reactor vessel to prevent an excessive rate of change of the reactor vessel temperature to avoid excessive stress (1-3). In States C and D, where it is planned operation to use the feedwater system, a limit is placed on the reactor fuel so that the feedwater temperature is maintained within the envelope of conditions considered by the plant safety analysis (1-4). For State D, a limit is observed on the temperature difference between the recirculation system and the reactor vessel to prevent the starting of the recirculation pumps. This operating restriction and limit prevents excessive stress in the reactor vessel (1-3).

15A.6.2.3.8 Nuclear System Water Quality Control

In all operating states, water of improper chemical quality could produce excessive stress as a result of chemical corrosion (1-3). Therefore, a limit is placed on reactor coolant chemical quality in all operating states. For all operating states where the nuclear system can be pressurized (States C and D), an additional limit on reactor coolant activity assures the validity of the analysis of the main steam line break accident (1-4).

15A.6.2.3.9 Nuclear System Leakage Control

Because excessive nuclear system leakage could occur only while the reactor vessel is pressurized, limits are applied only to the reactor vessel in States C and D. Observing these limits prevents vessel damage due to excessive stress (1-3) and assures the validity of the plant safety analysis (1-4).

15A.6.2.3.10 Core Reactivity Control

In State A during refueling outage, a limit on core fuel loading to assure that core reactivity is maintained within the envelope of conditions considered by the plant safety analysis (1-4). In all states, limits are imposed on the CRD system to assure adequate control of core reactivity so that core reactivity remains within the envelope of conditions considered by the plant safety analysis (1-4).

15A.6.2.3.11 Control Rod Worth Control

Any time the reactor is not shut down and is generating less than 20 percent power* (State D), a limit is imposed on the control rod pattern to assure that control rod worth is maintained within the envelope of conditions considered by the analysis of the CRDA (1-4).

15A.6.2.3.12 Refueling Restriction

By definition, planned operation Event 1 (refueling outage) applies only to State A. Observing the restrictions on the reactor fuel and on the operation of the CRD system within the specified limit maintains plant conditions within the envelope considered by the plant safety analysis (1-4).

15A.6.2.3.13 Primary Containment and Reactor Building Pressure and Temperature Control

In States C and D, limits are imposed on the suppression pool temperature to maintain primary containment pressure within the envelope considered by plant safety analysis (1-4). These limits assure an environment in which instruments and equipment can operate correctly within the primary containment. Limits on the suppression pool apply to the water temperature and water level to assure that it has the capability of absorbing the energy discharged during a safety/relief valve (SRV) blowdown.

15A.6.2.3.14 Stored Fuel Shielding, Cooling, and Reactivity

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* Technical Specification Amendment 91 changed this to ≤10 percent of rated thermal power.

Control

Because both new and spent fuel are stored during all operating states, stored fuel shielding, cooling, and reactivity control apply to all operating states. Limits are imposed on the spent fuel pool storage positions, water level, fuel handling procedures, and water temperature. Observing the limits on fuel storage positions assures that spent fuel reactivity remains within the envelope of conditions considered by the plant safety analysis (1-4). Observing the limits on water level assures shielding in order to maintain conditions within the envelope of conditions considered by the plant safety analysis (1-4) and provides the fuel cooling necessary to avoid fuel damage (1-2). Observing the limit on water temperature avoids excessive fuel pool stress (1-3).

15A.6.2.4 Operational Safety Evaluations

State A

In State A the reactor is in a shutdown condition, the vessel head is off, and the vessel is at atmospheric pressure. The applicable events for planned operations are refueling outage, achieving criticality, and cooldown (Events 1, 2, and 6, respectively).

Figure 15A-9 shows the necessary safety actions for planned operations, the corresponding plant systems, and the event for which these actions are necessary. As indicated in the diagram, the required safety actions are as follows:

1. Radioactive material release control.
2. Reactor vessel water level control.
3. Nuclear system temperature control.
4. Nuclear system water quality control.
5. Core reactivity control.
6. Refueling restrictions.
7. Stored fuel shielding, cooling, and reactivity control.
8. Reactor building temperature and pressure controls.

State B

In State B the reactor vessel head is off, the reactor is not shut down, and the vessel is at atmospheric pressure. Applicable planned operations are achieving criticality and achieving shutdown (Events 2 and 5, respectively).

Figure 15A-10 relates the necessary safety actions for planned operations, plant systems, and events for which the safety actions are necessary. The required safety actions for planned operation in State B are as follows:

1. Radioactive material release control.
2. Core power level control.
3. Reactor vessel water level control.
4. Nuclear system temperature control.
5. Nuclear system water quality control.
6. Core reactivity control.
7. Rod worth control.
8. Stored fuel shielding, cooling, and reactivity control.
9. Reactor building temperature and pressure control.

<u>State C</u>

In State C the reactor vessel head is on and the reactor is shut down. Applicable planned operations are achieving criticality and cooldown (Events 2 and 6, respectively).

Sequence diagrams relating safety actions for planned operations, plant systems, and applicable events are shown on Figure 15A-11.

The required safety actions for planned operation in State C are as follows:

1. Radioactive material release control.
2. Reactor vessel water level control.
3. Reactor vessel pressure control.
4. Nuclear system temperature control.
5. Nuclear system water quality control.
6. Nuclear system leakage control.
7. Core reactivity control.
8. Primary containment and reactor building pressure and temperature control.
9. Spent fuel storage shielding, cooling, and reactivity control.

State D

In State D the reactor vessel head is on and the reactor is not shut down. Applicable planned operations are achieving criticality, heatup, power operation, and achieving shutdown (Events 2, 3, 4, and 5, respectively).

Figure 15A-12 relates safety actions for planned operations, corresponding plant systems, and events for which the safety actions are necessary. The required safety actions for planned operation in State D are as follows:

1. Radioactive material release control.
2. Core coolant flow rate control.
3. Core power level control.
4. Core neutron flux distribution control.
5. Reactor vessel water level control.
6. Reactor vessel pressure control.
7. Nuclear system temperature control.
8. Nuclear system water quality control.
9. Nuclear system leakage control.
10. Core reactivity control.
11. Rod worth control.
12. Primary containment and reactor building pressure and temperature control.
13. Spent fuel storage shielding, cooling, and reactivity control.

15A.6.3 Anticipated Operational Transients

15A.6.3.1 General

The safety requirements and protection sequences for anticipated operational transients are described in the following paragraphs for Events 7 through 29. The protection sequence block diagrams show the sequence of front-line safety-related systems (Figures 15A-13 through 15A-36). The auxiliaries for the safety-related systems are indicated in the auxiliary diagrams (Figures 15A-7 and 15A-8).

15A.6.3.2 Required Safety Actions/Related Unacceptable

Consequences

The following list relates the safety actions for anticipated operational transients to mitigate or prevent the unacceptable safety consequences. Refer to Table 15A-7 for the unacceptable consequences criteria.

Safety Action	Criteria	Reason Action Required
Scram and/or recirculation pump trip (RPT)	2-2 2-3	To prevent fuel damage and to limit RPV system pressure rise.
Pressure relief	2-3	To prevent excessive RPV system pressure rise.
Core and primary containment cooling	2-1 2-2 2-4	To prevent fuel and primary containment damage in the event that normal cooling is interrupted.
Reactor vessel isolation	2-2	To prevent fuel damage by reducing the outflow of steam and water from the reactor vessel, thereby limiting the decrease in reactor vessel water level.
Restore ac power	2-2	To prevent fuel damage by restoring ac power to systems essential to other safety actions.
Prohibit normal rod movement	2-2	To prevent exceeding fuel limits during transients.
Primary containment isolation	2-1 2-4	To minimize radiological effects.

15A.6.3.3 Event Definitions and Operational Safety Evaluations

<u>Event 7 - Manual and Inadvertent Scram</u>

The deliberate manual or inadvertent automatic scram due to SOE is an event that can occur under any operating condition. Although assumed to occur here for analysis purpose, multi-Operator error or action is necessary to initiate such an event.

While all the safety criteria apply, no unique safety actions are required to control the planned operation-like event after effects of the subject initiation actions. In all operating states, the safety criteria are, therefore, met through the basic design of the plant systems. Figure 15A-13 identifies the protection sequences for this event.

Event 8 - Loss of Plant Instrument or Service Air System

Loss of all plant instrument or service air system causes reactor shutdown and the closure of all isolation valves except MSIVs. After partial insertion of control rods in State D, the MSIVs would close on low pressure causing actuation of the reactor protection system (RPS). Although these actions occur, they are not required to prevent unacceptable consequences in themselves. Multi-equipment failures would be necessary in order to cause the deterioration of the subject system to the point that the components supplied with instrument or service air would cease to operate normally and/or fail-safe. The results are less severe than those of Event 14 described later.

Isolation of the main steam lines can result in a transient for which some degree of protection is required only in operating States C and D. In operating States A and B, the main steam lines are continuously isolated.

Isolation of all main steam lines in operating State D during power operation is the most severe and rapid transient.

Figures 15A-14, 15A-20, and 15A-21 show how scram is accomplished by loss of air and/or main steam isolation through the actions of the RPS and the CRD system. The nuclear system pressure relief system provides pressure relief. Pressure relief, combined with loss of feedwater flow, causes reactor vessel water level to fall. The high-pressure core cooling systems supply water to maintain water level and to protect the core until normal operation is established.

Adequate reserve nitrogen supplies are maintained exclusively for the continual operation of the automatic depressurization system (ADS) SRVs until reactor shutdown is accomplished.

Event 9 - Inadvertent HPCS Pump Start (Moderator Temperature Decrease)

An inadvertent pump start (temperature decrease) is defined as an unintentional start of any nuclear system pump that adds sufficient cold water to the reactor coolant inventory to cause a measurable decrease in moderator temperature. This event is considered in all operating states because it can potentially occur under any operating condition. Since the high-pressure core spray (HPCS) pump operates over nearly the entire range of the operating states and delivers the greatest amount of cold water to the vessel, the following analysis describes its inadvertent operation rather than other nuclear steam supply system (NSSS) pumps (e.g., reactor core isolation cooling [RCIC], RHR, low-pressure core spray [LPCS]).

While all the safety criteria apply, no unique safety actions are required to control the adverse effects of such a pump start (i.e., pressure increase and temperature decrease in States A and C). In these operating states, the safety criteria are met through the basic design of the plant systems, and no safety action is specified. In States B and D, where the reactor is not shut down, the Operator or the plant normal control system can control any power changes in the normal manner of power control.

Figure 15A-15 illustrates the protection sequence for the subject event. Single failures to the normal plant control system pressure regulator or the feedwater controller systems result in further protection sequences. These are shown in Events 22 and 23.

Event 10 - Startup of Idle Recirculation Pump

The cold loop startup of an idle recirculation pump can occur in any state, and the transient is most severe and rapid for those operating states in which the reactor may be critical (States B and D). When the transient occurs in the range of 10 to 60 percent power operation, no safety action response is required. Reactor power is normally limited to approximately 60 percent design power because of core flow limitations while operating with one recirculation loop working. Above about 60 percent power, a high neutron flux scram is initiated. Figure 15A-16 shows the protective sequence for this event.

Event 11 - Recirculation Flow Control Failure (Increasing Flow)

A recirculation flow control failure causing increased flow is applicable in States C and D. In State D, the resulting increase in power level is limited by a reactor scram. As shown on Figure 15A-17, the scram safety action is accomplished through the combined actions of the neutron monitoring system (NMS), RPS, and CRD systems.

Event 12 - Recirculation Flow Control Failure Decreasing Flow)

This recirculation flow control malfunction causes a decrease in core coolant flow. This event is not applicable to States A and B because the reactor vessel head is off and the recirculation pumps normally would not be in use.

The number and type of flow controller failure modes determine the protection sequence for the event. For flow control valve control systems, the fast closure of one or two control valves results in the protective sequence of Figure 15A-18.

Event 13 - Trip of One or Both Recirculation Pumps

The trip of one recirculation pump produces a milder transient than does the simultaneous trip of two recirculation pumps.

The transient resulting from this two-loop trip is not severe enough to require any unique safety action. The transient is compensated for by the inherent nuclear stability of the reactor. This event is not applicable in States A and B because the reactor vessel head is off and the recirculation pumps normally would not be in use. The trip could occur in States C and D; however, the reactor can accommodate the transient with no unique safety action requirement. Figure 15A-19 provides the protection sequence for the event for one or both pump trip actuations.

In fact, this event constitutes an acceptable operational technique to reduce or minimize the effects of other event conditions. To this end, an engineered RPT capability is included in the plant operational design to reduce pressure and thermal-hydraulic transient effects. Operating States C and D are involved in this event.

Tripping a single recirculation pump requires no protection system operation.

The analyzed two-pump trip results in a high water level trip of the main turbine which further causes a stop valve closure and its subsequent scram actuation. Main steam isolation soon occurs and is followed by RCIC/HPCS systems initiation on low water level. Relief valve actuation follows.

Event 14 - Isolation of One or All Main Steam Lines

Isolation of the main steam lines can result in a transient for which some degree of protection is required only in operating States C and D. In operating States A and B, the main steam lines are normally isolation.

Isolation of all main steam lines is the most severe and rapid transient in operating State D during power operation.

Figure 15A-20 shows how scram is accomplished by main steam isolation through the actions of the RPS and the CRD system. The nuclear system pressure relief system provides pressure relief. Pressure relief, combined with loss of feedwater flow, causes reactor vessel water level to fall and HPCS and RCIC cooling systems supply water to maintain water level and to protect the core until normal operation is established.

Isolation of one main steam line causes a significant transient only in State D during high power operation. A scram is the only unique action required to avoid fuel damage and nuclear system overpressure. Because the feedwater system and main condenser remain in operation following the event, no unique requirement arises for core cooling.

As shown on Figure 15A-21, the scram safety action is accomplished through the combined actions of the NMS, RPS, and CRD systems.

Event 15 - Inadvertent Opening of the Safety/Relief Valve

The inadvertent opening of a SRV is possible in any operating state. The protection sequences are shown on Figure 15A-22. In States A, B, and C, the water level cannot be lowered far enough to threaten fuel damage; therefore, no safety actions are required.

In State D, there is a slight decrease in reactor pressure following the event. The pressure regulator closes the main turbine control valves enough to stabilize pressure at a level slightly below the initial value. There are no unique safety system requirements for this event.

If the event occurs when the feedwater system is not active in State D, a loss in the coolant inventory results in a reactor vessel isolation. The low water level signal initiates reactor vessel isolation. The nuclear system pressure relief system provides pressure relief.

Core cooling is accomplished by the RCIC and HPCS systems which are automatically initiated by low water level incident detection circuitry (IDC). The ADS or the manual relief valve system remain as the backup depressurization system if needed. After the vessel has depressurized, long-term core cooling is accomplished by the low-pressure coolant injection (LPCI), LPCS, and HPCS, which are initiated on a low water level by the IDC system or are manually operated. Suppression pool cooling is manually initiated.

Event 16 - Control Rod Withdrawal Error During Refueling and Startup Operations

Because a control rod withdrawal error resulting in an increase of positive reactivity can occur under any operating condition, it must be considered in all operating states. For this specific event situation, only States A and B apply.

Refueling No unique safety action is required in operating State A for the withdrawal of one control rod because the core is more than one control rod subcritical. Withdrawal of more than one control rod is precluded by the protection sequence shown on Figure 15A-23. During core alterations, the mode switch is normally in the REFUEL position, which allows the refueling equipment to be positioned over the core and also inhibits control rod withdrawal. This transient, therefore, applies only to operating State A.

No safety action is required because the total worth (positive reactivity) of one control rod is not adequate to cause criticality. Moreover, mechanical design of the control rod assembly prevents physical removal without removing the adjacent fuel assemblies.

Startup During low power operation (State B), the NMS via the RPS initiates a scram if necessary (Figure 15A-23).

Event 17 - Control Rod Withdrawal Error (During Power Operation)

Because a control rod withdrawal error resulting in an increase of positive reactivity can occur under any operating condition, it must be considered in all operating states. For this specific event situation, only States C and D apply.

During power operation (power range State D), a number of plant protective devices of various designs prohibit the control rod motion before critical levels are reached (Figure 15A-24). While in State C no protective action is needed.

In the power range (0 to 30 percent NBR), an out-of-sequence rod movement is prevented by using the nuclear measurement analysis and control rod worth minimizer (NUMAC RWM), which uses the banked position withdrawal sequence. In addition, the movement of the rod is monitored and limited within acceptable intervals either by neutronic effects or actual rod motion. The rod block monitor (RBM) provides movement surveillance. In addition to the rod motion control limiting system is the RPS. While in State C no protective action is needed.

Event 18 - Loss of Shutdown Cooling

The loss of RHRS-shutdown cooling can occur only during the low-pressure portion of a normal reactor shutdown and cooldown.

As shown on Figure 15A-25, for most single failures that could result in primary loss of shutdown cooling capabilities, no unique safety actions are required; in these cases, shutdown cooling is simply reestablished using redundant shutdown cooling (RHR) equipment. In the cases where the RHR-shutdown cooling suction line becomes inoperative, a unique arrangement for cooling arises. In States A and B in which the reactor vessel head is off, the LPCI, LPCS, or HPCS can be used to maintain reactor vessel water level. In States C and D in which the reactor vessel head is on and the system can be pressurized, the ADS or manual operation of relief valves, in conjunction with any of the ECCSs and the RHRS suppression pool cooling mode (both manually operated), can be used to maintain water level and remove decay heat. Suppression pool cooling is actuated to remove heat energy from the suppression pool system.

Event 19 - RHR Shutdown Cooling - Increased Cooling

A RHR shutdown cooling malfunction causing a moderator temperature decrease must be considered in all operating states. However, this event is not considered in States C and D if RPV system pressure is too high to permit operation of the shutdown cooling mode of RHR (Figure 15A-26). No unique safety actions are required to avoid the unacceptable safety consequences for transients as a result of a reactor coolant temperature decrease induced by misoperation of the shutdown cooling heat exchangers.

In States B and D, where the reactor is at or near critical, the slow power increase resulting from the cooler moderator temperature would be controlled by the Operator in the same manner normally used to control power in the source or intermediate power ranges.

Event 20 - Loss of All Feedwater Flow

A loss of feedwater flow results in a net decrease in the coolant inventory available for core cooling. A loss of feedwater flow can occur in States C and D. Appropriate responses to this transient include a reactor scram on low water level and restoration of RPV water level by RCIC and HPCS.

As shown on Figure 15A-27, the RPS and CRD systems effect a scram on low water level. The primary containment and reactor vessel isolation control system (CRVICS) and the MSIVs act to isolate the reactor vessel. After the MSIVs close, decay heat slowly raises system pressure to the lowest relief valve setting. Pressure is relieved by the RPV pressure relief system. Either the RCIC or HPCS system can maintain adequate water level for initial core cooling and to restore and maintain water level.

For long-term shutdown and extended core cooling, containment/suppression pool cooling systems are manually initiated.

The requirements for operating State C are the same as for State D except that the scram action is not required in State C.

Event 21 - Loss of a Feedwater Heater

Loss of a feedwater heater must be considered with regard to the nuclear safety operational criteria only in operating State D because significant feedwater heating does not occur in any other operating state.

A loss of feedwater heating causes a transient that requires no protective actions when the reactor is initially on flux control. If the reactor is on manual flow control, however, the neutron flux increase associated with this event reaches the scram setpoint. As shown on Figure 15A-28, the scram safety action is accomplished through actions of the NMS, RPS, and CRD systems.

Event 22 - Feedwater Controller Failure - Maximum Demand

A feedwater controller failure, causing an excess of coolant inventory in the reactor vessel, is possible in all operating states. Feedwater controller failures considered are those that would give failures of automatic flow control, manual flow control, or feedwater bypass valve control. In operating States A and B, no safety actions are required since the vessel head is removed and the moderator temperature is low. In operating State D, any positive reactivity effects by the reactor caused by cooling of the moderator can be mitigated by a scram. As shown on Figure 15A-29, the accomplishment of the scram safety action is satisfied through the combined actions of the NMS, RPS, and CRD systems. Pressure relief is required in States C and D and is achieved through the operation of the RPV pressure relief system. Initial restoration of the core water level is by the RCIC and HPCS systems. Prolonged isolation may require extended core cooling and containment/suppression pool cooling.

Event 23 - Pressure Regulator Failure (Open Direction)

A pressure regulator failure in the open direction, causing the opening of a turbine control or bypass valve, applies only in operating States C and D, because in other states the pressure regulator is not in operation. A pressure regulator failure is most severe and rapid in operating State D at high power.

The various protection sequences giving the safety actions are shown on Figure 15A-30. Depending on plant conditions existing prior to the event, scram is initiated either on main steam isolation, main turbine trip, reactor vessel high pressure, or reactor vessel low water level. The sequence resulting in reactor vessel isolation also depends on initial conditions.

With the mode switch in RUN, isolation is initiated when main steam line pressure decreases to approximately 850 psig. Under other conditions, isolation is initiated by reactor vessel low water level or other RPS systems. After isolation is completed, decay heat causes reactor vessel pressure to increase until limited by the operation of the relief valves. Core cooling following isolation can be provided by RCIC or HPCS. Shortly after reactor vessel isolation, normal core cooling can be reestablished via the main condenser and feedwater systems, or if prolonged isolation is necessary, extended core and primary containment cooling are manually actuated.

Event 24 - Pressure Regulator Failure - Closed

A pressure regulator failure in the closed direction (or downscale), causing the closing of turbine control valves, applies only in operating States C and D, because in other states the pressure regulator is not in operation.

A single pressure regulator failure downscale would result in little or no effect on the plant operation. The second pressure regulator would provide turbine-reactor control. If the second unit failed this would result in a worse situation, yet it is much less severe than Events 25, 27, 30, and 31. The dual pressure regulator failures are most severe and rapid in operating State D at high power.

The various protection sequences giving the safety actions are shown on Figure 15A-31. Upon failure of one pressure regulator downscale, normally a backup regulator maintains the plant in the present status upon the initial regulator downscale failure. An additional SACF of the backup regulator results in a high flux or pressure scram, system isolation, and subsequent extended isolation core cooling system actuations.

Event 25 - Main Turbine Trip (With Bypass System Operation)

A main turbine trip can occur only in operating State D (during heatup or power operation). A turbine trip during heatup is not as severe as a trip at full power because the initial power level is less than 30 percent, thus minimizing the effects of the transient and enabling return to planned operations via the bypass system operation. For a turbine trip above 30 percent power, a scram occurs via turbine stop valve closure as does a RPT. Subsequent relief valve actuation does occur. Eventual main steam isolation and RCIC and HPCS system initiation result from low water level. Figure 15A-32 depicts the protection sequences required for a main turbine trip. Main turbine trip and main generator trip are similar anticipated operational transients and, although main turbine trip is a more severe transient than main generator trip due to the rapid closure of the turbine stop valves, the required safety actions are the same.

Event 26 - Loss of Main Condenser Vacuum (Turbine Trip)

A loss of vacuum in the main turbine condenser can occur any time steam pressure is available and the condenser is in use; it is applicable to operating States C and D. Scram protection in State C is not needed since the reactor is not coupled to the turbine system.

For State D above 30 percent power, loss of condenser vacuum initiates a turbine trip, with its attendant stop valve closures, (which leads to scram) and a RPT. It also initiates isolation, pressure relief valve actuation, and RCIC and HPCS initial core cooling. Below 30 percent power (State D), scram is initiated by a high neutron flux signal. Figure 15A-33 shows the protection sequences. Decay heat necessitates extended core and suppression pool cooling. When the RPV depressurizes sufficiently, the low-pressure core cooling systems provide core cooling until a planned operation via a RHR shutdown cooling mode is achieved.

Event 27 - Main Generator Trip (With Bypass System Operation)

A main generator trip with bypass system operation can occur only in operating State D (during heatup or power operation). Fast closure of the main turbine control valves is initiated whenever an electrical grid disturbance occurs, which results in significant loss of electrical load on the generator. The turbine control valves are required to close as rapidly as possible to prevent excessive overspeed of the main turbine generator rotor. Closure of the turbine control valves causes a sudden reduction in steam flow which results in an increase in system pressure. Above 30 percent power, scram occurs as a result of fast control valve closure, and the RPT actuates. Subsequently, main steam isolation results, and pressure relief and initial core cooling by RCIC and HPCS take place. Prolonged shutdown of the turbine generator unit necessitates extended core and primary containment cooling. A generator trip during heatup (<30 percent) is not as severe because the turbine bypass system can accommodate the reactor steam generated, thus minimizing the effects of the transient and enabling return to planned operations. Figure 15A-34 depicts the protection sequences required for a main generator trip. Main generator trip and main turbine trip are similar anticipated operational transients. Although the main generator trip is a less severe transient than a turbine trip due to the rapid closure of the turbine stop valves, the required safety actions for both are the same sequence.

<u>Event 28 - Loss of Normal Onsite Power</u>

There is a variety of possible plant electrical component failures which could affect the reactor system. The total loss of onsite ac power is the most severe. The loss of auxiliary power transformer results in a sequence of events similar to that resulting from a loss of feedwater flow. The most severe situation occurs in State D during power operation. Figure 15A-35 shows the safety actions required to accommodate a loss of normal onsite power in States A, B, C, and D.

The RPS and CRD systems effect a scram on main turbine trip or loss of RPS power sources. The turbine control valve closure initiates a RPT. The CRVICS and the MSIVs act to isolate the reactor vessel. After the MSIVS close, decay heat slowly raises system pressure to the lowest relief valve setting. Pressure is relieved by the RPV pressure relief system. With continued isolation, decay heat may cause increased RPV pressure, and periodically lift relief valves which causes reactor vessel water level to decrease. The core and primary containment cooling sequences shown on Figure 15A-35 denote the short- and long-term actions for achieving adequate cooling.

<u>Event 29 - Loss of Offsite Power</u>

There is a variety of plant-grid electrical component failures which can affect reactor operation. The total loss of offsite ac power is the most severe. The loss of both onsite and offsite auxiliary power sources results in a sequence of events similar to that resulting from a loss of feedwater flow (Event 20). The most severe case occurs in State D during power operation. Figure 15A-36 shows the safety actions required for a total loss of offsite power (LOOP) in all States A, B, C, and D.

The RPS and CRD systems affect a scram from main turbine trip or loss of RPS power sources. The turbine control valve closure initiates RPT. The CRVICS and the MSIVs act to isolate the reactor vessel. After the MSIVs close, decay heat slowly raises system pressure to the lowest relief valve setting. Pressure is relieved by the nuclear system pressure relief system. After the reactor is isolated and feedwater flow has been lost, decay heat continues to increase RPV pressure, periodically lifting relief valves and causing reactor vessel water level to decrease. The core and primary containment cooling sequence shown on Figure 15A-36 shows the short- and long-term sequences for achieving adequate cooling.

15A.6.4 Abnormal Operational Transients

15A.6.4.1 General

The safety requirements and protection sequences for abnormal operational transients are described in the following paragraphs for Events 30 through 39. The protection sequence block diagrams show the sequence of safety-related systems (Figures 15A-37 through 15A-41). The auxiliaries for the safety-related systems are indicated in the auxiliary diagrams (Figures 15A-7 and 15A-8).

15A.6.4.2 Required Safety Actions/Related Unacceptable Consequences

The following list relates the safety actions for abnormal operational transients to mitigate or prevent the unacceptable safety consequences cited in Table 15A-8.

Safety Action	Related Unacceptable Consequence	Reason Action Required
Scram and/or RPT	3-2 3-3	To limit gross core-wide fuel damage and to limit nuclear system pressure rise
Pressure relief	3-3	To prevent excessive nuclear system pressure rise
Core, suppression pool, and primary containment cooling	3-2 3-4	To limit further fuel and primary containment damage in the event that normal cooling is interrupted
Reactor vessel	3-2	To limit further fuel

isolation		damage by reducing the outflow of steam and water from the reactor vessel, thereby limiting the decrease in reactor vessel water level
Restore ac power	3-2	To limit initial fuel damage by restoring ac power to systems essential to other safety actions
Primary containment isolation	3-1	To limit radiological effects

15A.6.4.3 Event Definition and Operation Safety Evaluation

Event 30 - Main Generator Trip (Without Bypass System Operation)

A main generator trip without bypass system operation can occur only in operating State D (during heatup or power operation). A generator trip during heatup without bypass operation results in the same situation as the power operation case. Figure 15A-37 depicts the protection sequences required for a main generator trip. The event is basically the same as that described in Event 27 at power levels above 30 percent. A scram, RPT, isolation, relief valve, and RCIC and HPCS operation immediately result in prolonged shutdown, which follows the same pattern as Event 27.

The thermal-hydraulic and thermodynamic effects on the core are more severe than with the bypass operating. Since the event is of lower probability than Event 27, the unacceptable consequences are less limiting.

The load rejection and turbine trip are similar abnormal operational transients and, although main generator trip is a less severe transient than a turbine trip due to the rapid closure of the turbine stop valves, the required safety actions are the same.

Event 31 - Main Turbine Trip (Without Bypass System Operation)

A main turbine trip without bypass can occur only in operating State D (during heatup or power operation). Figure 15A-38 depicts the protection sequences required for main turbine trips. Plant operation with bypass system operation above or below 30 percent power, due to bypass system failure, results in the same transient effects: a scram, a RPT, an isolation, subsequent relief valve actuation, and immediate RCIC and HPCS actuation. After initial shutdown, extended core and containment cooling is required as noted previously in Event 25.

Turbine trips without bypass system operation result in very severe thermal-hydraulic impacts on the reactor core. The allowable limit or acceptable calculational techniques for this event are less restrictive since the event is of lower probability of occurrence than the turbine trip with a bypass operation event.

Event 32 - Inadvertent Loading and Operation with Fuel Assembly in Improper Position

Operation with a fuel assembly in the improper position is shown on Figure 15A-39 and can occur in all operating states. No protection sequences are necessary relative to this event. Calculated results of worst fuel handling loading error will not cause fuel cladding integrity damage. It requires three independent equipment/Operator errors to allow this situation to develop.

Events 33 through 37 - Not Used

Event 38 - Recirculation Loop Pump Seizure

A recirculation loop pump seizure event considers the instantaneous stoppage of the pump motor shaft of one recirculation loop pump. The case involves operation at design power in State D. A main turbine trip occurs as vessel water level swell exceeds the turbine trip setpoint. This results in a turbine trip, scram and a RPT when the turbine stop valves close. Relief valve opening occurs to control pressure level and temperatures. The RCIC or HPCS system maintains vessel water level. Prolonged isolation requires core and containment cooling and possibly some radiological effluent control. The protection sequence for this event is given on Figure 15A-40.

Event 39 - Recirculation Loop Pump Shaft Break

A recirculation loop pump shaft break event considers the degraded, delayed stoppage of the pump motor shaft of one recirculation loop pump. The case involves operation at design power in State D. A main turbine trip occurs as vessel water level swell exceeds the turbine trip setpoint. This results in a turbine trip, scram, and a RPT when the turbine stop valves close. Relief valve opening occurs to control pressure level and temperatures. The RCIC or HPCS system maintains vessel water level. Prolonged isolation requires core and primary containment cooling and possibly some radiological effluent control. The protection sequence for this event is given on Figure 15A-41.

15A.6.5 Design Basis Accidents

15A.6.5.1 General

The safety requirements and protection sequences for accidents are described in the following paragraphs for Events 40 through

49. The protection sequence block diagrams show the safety actions and the sequence of safety-related systems used for the accidents (Figures 15A-42 through 15A-49). The auxiliaries for the safety-related systems are indicated in the auxiliary diagrams (Figures 15A-7 and 15A-8).

15A.6.5.2 Required Safety Actions/Unacceptable Consequences

The following list relates the safety actions for DBA to mitigate or prevent the unacceptable consequences cited in Table 15A-9.

Safety Action	Related Unacceptable Consequence	Reason Action Required
Scram	4-2 4-3	To prevent fuel cladding failure* and to prevent excessive nuclear system pressures
Pressure relief	4-3	To prevent excessive nuclear system pressure
Core Cooling	4-2	To prevent fuel cladding failure
Reactor vessel isolation	4-1	To limit radiological effect to the guideline values of 10CFR100
Isolate primary containment	4-1	To limit radiological effects to the guideline values to 10CFR100
Primary containment cooling	4-4	To prevent excessive pressure in the containment when containment is required
Prevent control rod ejection	4-2	To prevent fuel cladding failure
Restrict loss of reactor coolant (passive)	4-2	To prevent fuel cladding failure
Main control room environmental	4-5	To prevent overexposure to

control		radiation of plant personnel in the control room
Limit reactivity insertion rate (passive)	4-2 4-3	To prevent fuel cladding failure and to prevent excessive nuclear system pressure

15A.6.5.3 Event Definition and Operational Safety Evaluations

Event 40 - Control Rod Drop Accident

The CRDA results from an assumed failure of the control rod-to-drive mechanism coupling after the control rod (most reactive rod) becomes stuck in its fully-inserted position. It is assumed that the CRD is then fully withdrawn before the stuck rod falls out of the core. The control rod velocity limiter, an engineered safeguard, limits the control rod drop velocity. A limited amount of fuel damage is possible.

The CRDA is applicable in operating States B and D. However, the probability of a CRDA is minimized due to rod coupling integrity checks.

Figure 15A-42 presents the different protection sequences for the CRDA. As shown on Figure 15A-42, the reactor is automatically scrammed and isolated. For all design basis cases, the NMS, RPS, and CRD systems will provide a scram from high neutron flux. The main steam line RMS initiates the isolation of the reactor vessel*. Any high radiation in the containment areas will initiate closure of other possible pathways to atmosphere, as necessary.

After the reactor has been scrammed and isolated, the pressure relief system allows the steam (produced by decay heat) to be directed to the suppression pool. Initial core cooling is accomplished by either the RCIC or the HPCS or the normal feedwater system. With prolonged isolation as indicated on Figure 15A-42, the Reactor Operator (RO) initiates the RHR suppression pool cooling mode and depressurizes the vessel with the manual mode of the ADS or via normal manual relief valve operation.

Event 41 - Fuel Handling Accident

Because a fuel handling accident can potentially occur any time when fuel assemblies are being manipulated, either over the reactor core or in the spent fuel pool, this accident is

* Main steam line radiation monitoring trips are removed.

considered in all operating states. Considerations include mechanical fuel damage caused by drop impact and a subsequent release of fission products. The protection sequences pertinent to this accident are shown on Figure 15A-43. Reactor building isolation and standby gas treatment (SGT) operation are automatically initiated by the ventilation RMSs. Figure 15A-43 describes the protection sequences for the event.

Event 42 - Loss-of-Coolant Accidents Resulting from Postulated Piping Breaks Within RCPB Inside Containment (DBA-LOCA)

Pipe breaks inside the containment are considered only when the nuclear system is significantly pressurized (States C and D). The result is a release of steam and water into the containment. Consistent with NSOA criteria, the protection requirements consider all size line breaks including larger liquid recirculation loop piping down to small steam instrument line breaks. The most severe primary containment pressurization cases are the circumferential break of the largest recirculation system pipe and the circumferential break of the largest main steam line.

As shown on Figure 15A-44, in operating State C (reactor shut down, RPV head on), a pipe break accident up to the DBA can be accommodated within the nuclear safety operational criteria through the various operations of the MSIVs, ECCSs (HPCS, ADS,

LPCI, and LPCS), CRVICS, reactor building ventilation (HVR) system, SGT system, main control room heating, cooling and ventilation system, recombiners, equipment cooling systems, and the ESF detection circuitry. For small pipe breaks inside the primary containment, pressure relief is effected by the nuclear system pressure relief systems that transfer decay heat to the suppression pool. For large breaks, depressurization takes place through the break itself. In State D (reactor not shut down, RPV head on), the same equipment is required as in State C but, in addition, the RPS and the CRD system must operate to scram the reactor. The limiting items, on which the operation of the above equipment is based, are the allowable fuel cladding temperature and the containment pressure capability. The CRD housing supports are considered necessary whenever the system is pressurized to prevent excessive control rod movement through the bottom of the RPV following the postulated rupture of one CRD housing (a lesser case of the design basis LOCA and a related preventive of a postulated rod ejection accident).

After completion of the automatic action of the above equipment, manual operation of the RHR (suppression pool cooling mode) and ADS or relief valves (controlled depressurization) is required to maintain containment pressure and fuel cladding temperature within limits during extended core cooling.

Events 43, 44, 45 - Loss-of-Coolant Accidents Resulting from Postulated Pipe Breaks - Outside Primary Containment

Pipe break accidents outside the primary containment are assumed to occur any time the nuclear system is pressurized (States C and D). This accident is most severe during operation at high power (State D). In State C, this accident becomes a subset of the State D sequence.

The protection sequences for the various possible pipe breaks outside the primary containment are shown on Figure 15A-45. The sequences also show that for small breaks (breaks not requiring immediate action), the RO can use a large number of process indications to identify the break and isolate it.

In operating State D (reactor not shut down, but pressurized), scram is accomplished through operation of the RPS and the CRD system. Reactor vessel isolation is accomplished through operation of the MSIVs and the CRVICS.

For a main steam line break, initial core cooling is accomplished by either the HPCS or the ADS or manual relief valve operation in conjunction with the LPCS or LPCI. These systems provide parallel paths to effect initial core cooling, thereby satisfying the single-failure criterion. Extended core cooling is accomplished by the single-failure proof, parallel combination of the LPCI mode of RHR, the LPCS, and HPCS systems. The ADS or relief valve system operation and the RHR suppression pool cooling mode (both manually operated) are required to maintain primary containment pressure and fuel cladding temperature within limits during extended core cooling.

<u>Event 46 - Gaseous Radwaste System Leak or Failure</u>

It is assumed that the line leading to the steam jet air ejector (SJAE) fails near the main condenser. This results in activity normally processed by the OFG treatment system being discharged directly to the turbine building and subsequently through the ventilation system to the environment. This failure results in a loss-of-flow signal to the OFG system. This event can be considered only under States C and D, and is shown on Figure 15A-46.

The RO initiates a normal shutdown of the reactor to reduce the gaseous activity being discharged. A loss of main condenser vacuum results (timing depending on leak rate) in a main turbine trip and ultimately a reactor scram. Refer to Event 26 for reactor protection sequence (Figure 15A-33).

<u>Event 47 - Augmented Offgas Treatment System Failure</u>

An evaluation of events that could cause a gross failure in the OFG system has resulted in the identification of a postulated seismic event, more severe than the one for which the system is designed, as the only conceivable event that could cause significant damage.

The detected gross failure of this system results in manual isolation of this system from the main condenser. The isolation results in high main condenser pressure and ultimately a reactor scram. Protective sequences for the event are shown on Figure 15A-47.

The undetected postulated failure soon results in a system isolation necessitating reactor shutdown because of loss of vacuum in the main condenser. This transient has been analyzed in Event 26 (Figure 15A-33).

<u>Event 48 - Liquid Radwaste System Leak or Failure</u>

Releases that could occur inside and outside the primary containment, not covered by Events 40, 41, 42, 43, 44, 45, 47, and 48, include small spills and equipment leaks of radioactive materials inside structures housing the subject process equipment. Conservative values of leakage have been assumed and evaluated in the plant under routine releases. The offsite dose that results from any small spill which could occur outside primary containment is negligible in comparison to the dose resulting from the accountable (expected) plant leakages.

The protective sequences for this event are provided in Figure 15A-48.

<u>Event 49 - Liquid Radwaste System - Storage Tank Failure</u>

An unspecified event causes the complete release of the average radioactivity inventory from the storage tank containing the largest quantities of significant radionuclides from the LWS system. This is assumed to be one of the evaporator bottom waste tanks in the radwaste building. The airborne radioactivity released during the accident passes directly to the environment via the radwaste/reactor building vent.

The postulated events that could cause release of the radioactive inventory of the concentrator waste tank include cracks in the vessels and an Operator error. The possibility of small cracks and consequent low-level release rates receives primary consideration in system and component design. The concentrator waste tank is designed to operate at atmospheric pressure and 200°F maximum temperature so the possibility of failure is considered small. A liquid radwaste release caused by Operator error is also considered a remote possibility. Operating techniques and administrative procedures emphasize detailed system and equipment operating instruction. A positive action interlock system is provided to prevent inadvertent opening of a drain valve. Should a release of liquid radioactive wastes occur, floor drain sump pumps in the floor of the radwaste building receive a high water level alarm, activate automatically, and remove the spilled liquid to a contained storage tank.

The protective sequences for this event are provided on Figure 15A-49.

15A.6.6 Special Events

15A.6.6.1 General

Additional special events are postulated to demonstrate that the plant is capable of accommodating off-design occurrences (Events 50 through 53). These events are beyond the safety requirements of the other event categories. The safety actions shown on the sequence diagrams (Figures 15A-50 through 15A-53) for the additional special events follow directly from the requirements cited in the demonstration of the plant capability.

Auxiliary system support analyses are shown on Figures 15A-7 and 15A-8.

15A.6.6.2 Required Safety Action/Unacceptable Consequences

The following list relates the safety actions for special events to provide the capability demonstration indicated in Table 15A-10:

Safety Action	Related Unacceptable Consequence	Reason for Action Available
Main Control Room Considerations		
Mutually initiate all shutdown controls from remote shutdown room or local panels	5-1 5-2	Local panel control has been provided and is available outside main control room
Manually initiate standby liquid control system (SLCS)	5-3	SLCS to control reactivity to cold shutdown is available

Shipping Cask Considerations

See Section 9.1.4.

15A.6.6.3 Event Definitions and Operational Safety Evaluation

Event 50 - Shipping Cask Drop

Spent Fuel Cask Drop Due to the redundant polar crane, the cask drop accident is not believed to be a credible accident. However, the accident is hypothetically assumed to occur as a consequence of an unspecified failure of the cask lifting mechanism, thereby allowing the cask to fall.

It is assumed that a spent fuel shipping cask containing irradiated fuel assemblies is in the process of being moved with the cask suspended from the crane above the rail car. The fuel assemblies have been out of the reactor for at least 90 days.

Through some unspecified failure, the cask is released from the crane and falls 30 to 100 ft onto the rail car. Some of the coolant in the outer cask structure may leak from the cask.

The RO will ascertain the degree of cask damage and, if possible, make the necessary repairs and refill the cask coolant to its normal level if coolant has been lost. It is assumed that if the coolant is lost from the external cask shield, the Operator will establish forced cooling of the cask by introducing water into the outer structure annulus or by spraying water on the cask exterior surface. Maintaining the cask in a cool condition will ensure no fuel damage as a result of a temperature increase due to decay heat.

Since the cask is still within the reactor building volume, any activity postulated to be released can be accommodated by the SGT system and elevated release point (main stack). The protective sequences for this event are provided on Figure 15A-50.

<u>New Fuel Cask Drop</u> See Section 9.1.4.

<u>Event 51 - Reactor Shutdown - Anticipated Transient Without Scram</u>

Reactor shutdown from a plant transient occurrence (e.g., turbine trip) without the use of control rods has been evaluated to determine the capability of the plant to be safely shut down. The event is applicable in any operating state. Figure 15A-51 shows the protection sequence for this extremely improbable and demanding event in each operating state. In State A, no sequence is shown because the reactor is already in the condition finally required by definition.

State D is the most limiting case. Upon initiation of the plant transient situation (e.g., turbine trip), a scram is initiated but no control rods are assumed to move. The recirculation pumps are tripped by turbine control valve closure or low water level or high reactor pressure. If the nuclear system becomes isolated from the main condenser, heat can be transferred from the reactor to the suppression pool via the relief valves. The ESF circuitry initiates operation of the HPCS on low water level which maintains reactor vessel water level. The SLCS is manually initiated and the transition from low power neutron heat to decay heat occurs. The RHR suppression pool cooling mode is used to remove the low power neutron and decay heat from the suppression pool as required. When RPV pressure falls to the 100 to 200 psig level, the RHR shutdown cooling mode is started and continued to cold shutdown. Various single-failure analytical exercises can be examined to show additional capabilities to accommodate further plant system degradations.

Event 52 - Reactor Shutdown From Outside Main Control Room

This event is investigated to evaluate the capability of the plant to be safely shut down and cooled to the cold shutdown state from outside the main control room. The event is applicable in operating States A, B, C, and D.

Figure 15A-52 shows the protection sequences for this event in each operating state. In State A, no sequence is shown because the reactor is already in the condition finally required for the event. In State C, only cooldown is required since the reactor is already shut down.

A scram from outside the main control room can be achieved by opening the ac supply breakers for the RPS. If the nuclear system becomes isolated from the main condenser, decay heat is transferred from the reactor to the suppression pool via the relief valves or shutdown cooling placed in service. The ESF circuitry initiates operation of the RCIC and HPCS systems on low water level which maintains reactor vessel water level, and the RHR suppression pool cooling mode is used to remove the decay heat from the suppression pool if required. When reactor pressure falls below 135 psig level, the RHR shutdown cooling mode is started.

Event 53 - Reactor Shutdown Without Control Rods

Reactor shutdown without control rods is an event requiring an alternate method of reactivity control, the SLCS. By definition, this event can occur only when the reactor is not already shut down. Therefore, this event is considered only in operating States B and D.

The SLCS must operate to avoid unacceptable consequence criteria 5-3. The design bases for the SLCS result from these operating criteria when applied under the most severe conditions (State D at rated power). The SLCS is manually initiated in States B and D (Figure 15A-53).

15A.7 REMAINDER OF NSOA

With the information presented in the protection sequence block diagrams, the auxiliary diagrams, and the commonality of auxiliary diagrams, it is possible to determine the functional and hardware requirements for each system. This is done by considering each event in which the system is employed and deriving a limiting set of operational requirements. This limiting set of operational requirements establishes the lowest acceptable level of performance for a system or component, or the minimum number of components or portions of a system that must be operable for plant operation to continue.

The operational requirements derived using the above process may be complicated functions of operating states, parameter ranges, and hardware conditions. The final step is to simplify these complex requirements into Technical Specifications that encompass the operational requirements that can be used by plant operations and management personnel.

15A.8 CONCLUSIONS

It is concluded that the nuclear safety operational and plant design basis criteria are satisfied when the plant is operated in accordance with the nuclear safety operational requirements determined by the method presented in this appendix.

15A.9 REFERENCE

1. Hirsch, M. M. Methods for Calculating Safe Test Intervals and Allowable Repair Times for Engineered Safeguard Systems, NEDO-10739, January 1973.

TABLE 15A-1

NORMAL OPERATION

NSOA Event No.	Event Description	NSOA Event Figure No.	BWR Operating State			
			A	B	C	D
1	Refueling	15A-9 through 15A-12	X			
2	Achieving criticality		X	X	X	X
3	Heatup	15A-12				X
4	Power operation	15A-12				X
5	Achieving shutdown	15A-10, 15A-12		X		X
6	Cooldown	15A-9, 15A-11	X		X	

TABLE 15A-2

ANTICIPATED OPERATIONAL TRANSIENTS

NSOA Event No.	Event Description	NSOA Event Figure No.	FSAR Section No.	BWR Operating State			
				A	B	C	D
7	Manual or inadvertent scram	15A-13	7.2	X	X	X	X
8	Loss of plant instrument and/or service air systems	15A-14	9.3.1	X	X	X	X
9	Inadvertent startup of HPCS pump	15A-15	15.5.1	X	X	X	X
10	Inadvertent startup of idle recirculation loop pump	15A-16	15.4.4	X	X	X	X
11	Recirculation loop flow control failure with increasing flow	15A-17	15.4.5			X	X
12	Recirculation loop flow control failure with decreasing flow	15A-18	15.3.2			X	X
13	Recirculation loop pump trip	15A-19	15.3.1			X	X
14	Inadvertent MSIV closure With one valve With four valves	 15A-20 15A-21	15.2.4			 X X	 X X
15	Inadvertent operation of one safety/relief valve	15A-22	15.6.1	X	X	X	X
16	Continuous control rod withdrawal error During startup During refueling	15A-23	15.4.1		 X		
17	Continuous control rod withdrawal rod error at power	15A-24	15.4.2			X	X
18	RHR - shutdown cooling failure loss of cooling	15A-25	15.2.9	X	X	X	X
19	RHR - shutdown cooling failure increased cooling	15A-26	15.1.6	X	X	X	X
20	Loss of all feedwater flow	15A-27	15.2.7			X	X
21	Loss of feedwater heater	15A-28	15.1.1				X
22	Feedwater controller failure maximum demand - low power	15A-29	15.1.2	X	X	X	X
23	Pressure regulator failure - open	15A-30	15.1.3			X	X
24	Pressure regulator failure - closed	15A-31	15.2.1			X	X

TABLE 15A-2 (Cont'd.)

NSOA Event No.	Event Description	NSOA Event Figure No.	FSAR Section No.	BWR Operating State			
				A	B	C	D
25	Main turbine trip with bypass system operational	15A-32	15.2.3				X
26	Loss of main condenser vacuum	15A-33	15.2.5			X	X
27	Main generator trip (load rejection) with bypass system operational	15A-34	15.2.2				X
28	Loss of plant normal onsite ac power	15A-35	15.2.6	X	X	X	X
29	Loss of plant normal offsite ac power	15A-36	15.2.6	X	X	X	X

TABLE 15A-3

ABNORMAL OPERATIONAL TRANSIENTS

NSOA Event No.	Event Description	NSOA Event Figure No.	FSAR Section No.	BWR Operating State			
				A	B	C	D
30	Main generator trip (load rejection) with bypass system failure	15A-37	15.2.2				X
31	Main turbine trip with bypass system failure	15A-38	15.2.3				X
32	Inadvertent loading and operation of a fuel assembly in an improper position	15A-39	15.4.7	X	X	X	X
38	Recirculation loop pump seizure for one loop	15A-40	15.3.3				X
39	Recirculation loop pump shaft break	15A-41	15.3.4				X

TABLE 15A-4

DESIGN BASIS ACCIDENTS

NSOA Event No.	Event Description	NSOA Event Figure No.	FSAR Section No.	BWR Operating State			
				A	B	C	D
40	Control rod drop accident	15A-42	15.4.9				X
41	Fuel handling accident	15A-43	15.7.4	X	X	X	X
42	Loss-of-coolant accident* resulting from spectrum of postulated piping breaks within the RPCB inside containment	15A-44	15.6.5			X	X
43	Small, large, steam and liquid piping breaks outside containment	15A-45	15.6.4			X	X
44	Instrument line break outside drywell	15A-45	15.6.2			X	X
45	Feedwater line break outside containment	15A-45	15.6.6			X	X
46	Gaseous radwaste system leak or failure	15A-46	15.7.1	X	X	X	X
47	Augmented offgas treatment system failure	15A-47	15.7.1	X	X	X	X
48	Liquid radwaste system leak or failure	15A-48	15.7.2	X	X	X	X
49	Liquid radwaste system storage tank failure	15A-49	15.7.3	X	X	X	X

* Small, intermediate, and large.

TABLE 15A-5

SPECIAL EVENTS

NSOA Event No.	Event Description	NSOA Event Figure No.	FSAR Section No.	BWR Operating State			
				A	B	C	D
50	Shipping cask drop	15A-50	15.7.5	X	X	X	X
51	Reactor shutdown from ATWS	15A-51	15.8	X	X	X	X
52	Reactor shutdown from outside main control room	15A-52	7.5	X	X	X	X
53	Reactor shutdown without control rods	15A-53	9.3.5		X		X

TABLE 15A-6

UNACCEPTABLE CONSEQUENCES CRITERIA
PLANT EVENT CATEGORY: NORMAL OPERATION

Unacceptable Consequences
1-1 Release of radioactive material to the environs that exceeds the limits of either 10CFR20 or 10CFR50.
1-2 Fuel failure to such an extent that were the freed fission products released to the environs via the normal discharge paths for radioactive material, the limits of 10CFR20 would be exceeded.
1-3 Nuclear system stress in excess of that allowed for planned operation by applicable industry codes.
1-4 Existence of a plant condition not considered by plant safety analyses.

TABLE 15A-7

UNACCEPTABLE CONSEQUENCES CRITERIA
PLANT EVENT CATEGORY: ANTICIPATED OPERATIONAL TRANSIENTS

Unacceptable Consequences
2-1 Release of radioactive material to the environs that exceeds the limits of 10CFR20.
2-2 Reactor operation induced fuel cladding failure as a direct result of the transient analysis above the MCPR uncertainty level (0.1%).
2-3 Nuclear system stress exceeding that allowed for transients by applicable industry codes.
2-4 Primary containment stresses exceeding those allowed for transients by applicable industry codes when primary containment is required.

TABLE 15A-8

UNACCEPTABLE CONSEQUENCES CRITERIA
PLANT EVENT CATEGORY: ABNORMAL OPERATIONAL TRANSIENTS

Unacceptable Consequences
3-1 Radioactive material release exceeding the guideline values of a small fraction of 10CFR100.
3-2 Reactor operation induced fuel cladding failure as a direct result of the transient analysis above the MCPR uncertainty level (0.1%).
3-3 Nuclear system stresses exceeding those allowed for transients by applicable industry codes.
3-4 Primary containment stresses exceeding those allowed for accidents by applicable industry codes when primary containment is required.

TABLE 15A-9

UNACCEPTABLE CONSEQUENCES CRITERIA
PLANT EVENT CATEGORY: DESIGN BASIS ACCIDENTS

Unacceptable Consequences
4-1 Radioactive material release exceeding the guideline values of 10CFR100.
4-2* Failure of the fuel barrier as a result of exceeding mechanical or thermal limits.
4-3 Nuclear system stresses exceeding those allowed for accidents by applicable industry codes.
4-4 Primary containment stresses exceeding those allowed for accidents by applicable industry codes when primary containment is required.
4-5 Overexposure to radiation of plant main control room personnel.

* Failure of the fuel barrier includes fuel cladding fragmentation (LOCA) and excessive fuel enthalpy (CRDA).

TABLE 15A-10

UNACCEPTABLE CONSEQUENCES CONSIDERATIONS
PLANT EVENT CATEGORY: SPECIAL EVENTS

Special Events Considered

A Reactor shutdown from outside the main control room.

B Reactor shutdown without control rods.

C Reactor shutdown with ATWS.

D Shipping cask drop.

Capability Demonstration

5-1 Ability to shut down reactor by manipulating controls and equipment outside the main control room.

5-2 Ability to bring the reactor to the cold shutdown condition from outside the main control room.

5-3 Ability to shut down the reactor independent of control rods.

5-4 Ability to contain radiological contamination.

5-5 Ability to limit radiological exposure.

TABLE 15A-11

BWR OPERATING STATES*

Condition	States A	B	C	D
Reactor vessel head off	X	X		
Reactor vessel head on			X	X
Shutdown	X		X	
Not shutdown		X		X

Definition

For the purpose of this analysis, shutdown is defined as K_{eff} sufficiently less than 1.0 that the full withdrawal of any one control rod could not produce criticality under the most restrictive potential conditions of temperature, pressure, core age, and fission product concentrations.

* Further discussion is provided in Section 15A.6.2.4.

APPENDIX 15B

RECIRCULATION SYSTEM SINGLE LOOP OPERATION

APPENDIX 15B

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RECIRCULATION SYSTEMS SINGLE-LOOP OPERATION

Cycle-specific information is covered in Appendix A, Section A.15B.

15B.1 INTRODUCTION AND SUMMARY

Single-loop operation (SLO) at reduced power is highly desirable in the event recirculation pump or other component maintenance renders one loop inoperative. To justify SLO, accidents and abnormal operational transients associated with power operations, as presented in Sections 6.2 and 6.3 and the main text of Chapter 15.0, were reviewed for the single-loop case with only one pump in operation. This appendix presents the results of this safety evaluation for the operation of the Nine Mile Point Nuclear Station - Unit 2 (Unit 2) with single recirculation loop inoperable. The evaluation was initially performed for the GE 8x8NB fueled Unit 2 Reload 1 Cycle 2 core and the GE 6 (BP/P8x8R) fuel that remained in the core from Cycle 1. For Reload 3 Cycle 4, SLO was reevaluated for effects of GE 11 fuel, and for Reload 9 Cycle 10, SLO was reevaluated for effects of GE 14 fuel. It was determined that the results of the previous analysis were still valid for rated power of 3,467 MWt. For EPU (3,988 MWt), the ability to operate in SLO is unchanged. All of the transient events have significant fuel thermal margin. The previous maximum average planar linear heat generation rate (MAPLHGR) multipliers were shown to adequately cover a LOCA event. SLO operating conditions are within the extended load line limit analysis (ELLLA, 108% rod line) operating domain up to a maximum power of approximately 82 percent of original rated power (3,323 MWt) and 60 percent of core flow. The SLO operational and analytical bases are unchanged with the extension of the Unit 2 operating domain to MELLLA or MELLLA+. SLO is not extended into the MELLLA or MELLA+ operating domain for Unit 2. The following operating flexibility options are considered concurrently with SLO (Reference 15B.8-14):

1. Two safety relief valve (SRV)/automatic depressurization system (ADS) valves out of service (OOS) and/or one main steam isolation valve (MSIV) OOS, and

2. End-of-cycle (EOC) recirculation pump trip (RPT) OOS, or turbine bypass OOS.

Permissible operating option combinations are illustrated in Table 15.0-6.

Increased uncertainties in the core total flow and traversing in-core probe (TIP) readings resulted in a 0.01 incremental increase in the minimum critical power ratio (MCPR) fuel cladding integrity safety limit during SLO. No increase in rated MCPR operating limit and no change in the flow-dependent MCPR limit ($MCPR_f$) are required because all abnormal operational transients analyzed for SLO indicated that there is more than enough MCPR margin to compensate for this increase in MCPR safety limit. The recirculation flow rate dependent rod block and scram setpoint equation given in Technical Specifications is adjusted for one-pump operation.

Thermal-hydraulic stability was evaluated for its adequacy with respect to General Design Criteria (GDC) 12 (10CFR50 Appendix A). It is shown that SLO satisfies this stability criterion. It is further shown that the increase in neutron noise observed during SLO is independent of system stability margin.

To prevent potential control oscillations from occurring in the recirculation flow control system, the flux controller should be in manual for SLO.

The limiting MAPLHGR reduction factor for SLO for the GE 8x8NB Reload 1 Cycle 2 fuel is 0.79, and for the GE11, GE14, and GNF2 fuel it is calculated to be 0.78. The MAPLHGR reduction factor for the BP/P8x8 fuel remaining in the core from Cycle 1 is 0.81.

The containment response for a design basis accident (DBA) recirculation line break with SLO is bounded by the rated power two-loop operation analysis presented in Section 6.2. This conclusion covers all analyzed SLO power/flow conditions, including operation up into the MELLLA region.

The impact of SLO on the anticipated transient without scram (ATWS) analysis was evaluated. It is found that all ATWS acceptance criteria are met during SLO.

The fuel thermal and mechanical duty for transient events occurring during SLO is found to be bounded by the fuel design bases. The average power range monitor (APRM) fluctuation should not exceed a flux amplitude of $\pm$15 percent of rated and the core plate differential pressure fluctuation should not exceed 3.2 psi peak-to-peak to be consistent with the fuel rod and assembly design bases.

A recirculation pump drive flow limit is imposed for SLO. The highest drive flow that meets acceptable vessel internal vibration criteria is the drive flow limit for SLO.

The steady state drive flow limit in SLO was determined during the startup test program at Unit 2 to be 41,800 gpm. In addition, full flow testing performed at the BWRVIP/EPRI jet pump test facility with the slip joint clamps installed ensures no slip joint instability induced vibration for drive flows greater than the steady state flow of 41,800 gpm (Reference 9).

15B.2 MINIMUM CRITICAL POWER RATIO FUEL CLADDING INTEGRITY SAFETY LIMIT

Except for core total flow and TIP reading, the uncertainties used in the statistical analysis to determine the MCPR fuel cladding integrity safety limit are not dependent on whether coolant flow is provided by one or two recirculation pumps. Uncertainties used in the two-loop operation analysis are documented in the Final Safety Analysis Report (FSAR). A 6-percent core flow measurement uncertainty has been established for SLO (compared to 2.5 percent for two-loop operation). As shown below, this value conservatively reflects the one standard deviation (one sigma) accuracy of the core flow measurement system documented in Reference 15B.8-1. The random noise component of the TIP reading uncertainty was revised for single recirculation loop operation to reflect the operating plant test results given in Subsection 15B.2.2. This revision resulted in a SLO process computer effective TIP uncertainty of 6.8 percent of initial cores and 9.1 percent for reload cores. Comparable two-loop process computer uncertainty values are 6.3 percent for initial cores and 8.7 percent for reload cores. The net effect of these two revised uncertainties is a 0.01 increase in the required MCPR fuel cladding integrity safety limit. The above methodology and uncertainties were revised per Reference 15B.8-15.

15B.2.1 Core Flow Uncertainty

15B.2.1.1 Core Flow Measurement During Single-Loop Operation

The jet pump core flow measurement system is calibrated to measure core flow when both sets of jet pumps are in forward flow; total core flow is the sum of the indicated loop flows. For SLO, however, some inactive jet pumps will be backflowing (at active pump flow above approximately 38 percent). Therefore, the measured flow in the backflowing jet pumps must be subtracted from the measured flow in the active loop to obtain the total core flow. In addition, the jet pump coefficient is different for reverse flow than for forward flow, and the measurement of reverse flow must be modified to account for this difference.

In SLO, the total core flow is derived by the following formula:

$$Total\ Core\ Flow = \begin{pmatrix} Active\ Loop \\ Indicated\ Flow \end{pmatrix} - C \begin{pmatrix} Inactive\ Loop \\ Indicated\ Flow \end{pmatrix}$$

Where C (= 0.95) is defined as the ratio of "Inactive Loop True Flow" to "Inactive Loop Indicated Flow." "Loop Indicated Flow" is the flow measured by the jet pump "single-tap" loop flow summers and indicators, which are set to read forward flow correctly.

The 0.95 factor was the result of a conservative analysis to appropriately modify the single-tap flow coefficient for reverse flow.* If a more exact, less conservative core flow is required, special in-reactor calibration tests would have to be made. Such calibration tests would involve: calibrating core support plate ΔP versus core flow during one-pump and two-pump operation along with 100-percent flow control line and calculating the correct value of C based on the core support plate ΔP and the loop flow indicator readings.

15B.2.1.2 Core Flow Uncertainty Analysis

The uncertainty analysis procedure used to establish the core flow uncertainty for one-pump operation is essentially the same as for two-pump operation with some exceptions. The core flow uncertainty analysis is described in Reference 15B.8-1. The analysis of one-pump core flow uncertainty is summarized below.

For SLO, the total core flow can be expressed as follows (refer to Figure 15B.2-1):

$$W_C = W_A - W_I$$

Where:

W_C = total core flow

W_A = active loop flow

W_I = inactive loop (true) flow

By applying the "propagation of errors" method to the above equation, the variance of the total flow uncertainty can be approximated by:

$$\sigma^2_{W_C} = \sigma^2_{W_{sys}} + \left(\frac{1}{1-a}\right)^2 \sigma^2_{W_{A_{rand}}} + \left(\frac{a}{1-a}\right)^2 \left(\sigma^2_{W_{I_{rand}}} + \sigma^2_C\right)$$

Where:

$\sigma_{W\ C}$ = uncertainty of total core flow

$\sigma_{W\ sys}$ = uncertainty systematic to both loops

$\sigma_{WA\ rand}$ = random uncertainty of active loop only

$\sigma_{WI\ rand}$ = random uncertainty of inactive loop only

---

* The analytical expected value of the "C" coefficient for Unit 2 is 0.88.

σ_c = uncertainty of "C" coefficient

a = ratio of inactive loop flow (W_I) to active loop flow (W_A)

From an uncertainty analysis, the conservative, bounding values of σ_{Wsys}, σ_{WArand}, σ_{WIrand} and σ_c are 1.6 percent, 2.6 percent, 3.5 percent, and 2.8 percent, respectively. Based on the above uncertainties and a bounding value of 0.36* for "a", the variance of the total flow uncertainty is approximately:

$$\sigma_{Wc}^2 = (1.6)^2 + \left(\frac{1}{1-0.36}\right)^2 (2.6)^2 + \left(\frac{0.36}{1-0.36}\right)^2 \left((3.5)^2 + (2.8)^2\right) = (5.0\%)^2$$

When the effect of 4.1-percent core bypass flow split uncertainty at 12-percent (bounding case) bypass flow fraction is added to the total core flow uncertainty, the active coolant flow uncertainty is:

$$\sigma^2_{\substack{active\\coolant}} = (5.0\%)^2 + \left(\frac{0.12}{1-0.12}\right)^2 (4.1\%)^2 = (5.1\%)^2$$

which is less than the 6-percent flow uncertainty assumed in the statistical analysis.

In summary, core flow during one-pump operation is measured in a conservative way and its uncertainty has been conservatively evaluated.

15B.2.2 TIP Reading Uncertainty

To ascertain the TIP noise uncertainty for single recirculation loop operation, a test was performed at an operating boiling water reactor (BWR). The test was performed at a power level 59.3 percent of rated with a single recirculation pump in operation (core flow 46.3 percent of rated). A rotationally symmetric control rod pattern existed during the test.

Five consecutive traverses were made with each of five TIP machines giving a total of 25 traverses. Analysis of this data resulted in a nodal TIP noise of 2.85 percent. Use of this TIP noise value as a component of the process computer total uncertainty results in a one-sigma process computer total effective TIP uncertainty value for SLO of 6.8 percent for initial cores and 9.1 percent for reload cores.

* This flow split ratio varies from about 0.13 to 0.36. The 0.36 value is a conservative bounding value. The analytical expected value of the flow split ratio for Unit 2 is ~0.23.

15B.3 MCPR OPERATING LIMIT

15B.3.1 Abnormal Operating Transients

Operating with one recirculation loop results in a maximum analyzed power output which is about 20 percent below that which is attainable for two-pump operation. Therefore, the consequences of abnormal operation transients from one-loop operation will be considerably less severe than those analyzed from a two-loop operational mode. For pressurization, flow increase, flow decrease, and cold water injection transients, the results presented in Chapter 15 bound both the thermal and overpressure consequences of one-loop operation.

Figure 15B.3-1 shows the consequences of a typical pressurization transient (generator load rejection) as a function of power level. As can be seen, the consequences of one-loop operation are considerably less because of the associated reduction in operating power level.

The consequences of flow decrease transients are also bounded by the full power analysis. A single pump trip from one-loop operation is less severe than a two-pump trip from full power because of the reduced initial power level.

The worst flow increase transient results from recirculation flow controller failure, and the worst cold water injection transient results from the loss of feedwater heater. For the former, the $MCPR_f$ (K_f) curve is derived assuming both recirculation loop controllers fail. This condition produces the maximum possible power increase and hence maximum delta critical power ratio (CPR) for transients initiated from less than rated power and flow. When operating with only one recirculation loop, the flow and power increase associated with this failure with only one loop will be less than that associated with both loops; therefore, the K_f curve derived with the two-pump assumption is conservative for SLO. The latter event, loss of feedwater heating, is generally the most severe cold water increase event with respect to increase in core power. This event is caused by positive reactivity insertion from core inlet subcooling and it is relatively insensitive to initial power level. A generic statistical loss of feedwater heater analysis using different initial power levels and other core design parameters concluded one-pump operation with lower initial power level is conservatively bounded by the full-power two-pump analysis. Inadvertent restart of the idle recirculation pump has been analyzed in the FSAR (Chapter 15.4.4) and is still applicable for SLO.

From the above discussions, it is concluded that the transient consequence from one-loop operation is bounded by previously submitted full-power analyses. The maximum power level that can be attained with one-loop operation is only restricted by the MCPR and overpressure limits established from a full-power analysis.

In the following sections, the results of two of the most limiting transients analyzed for SLO are presented. They are, respectively:

a. feedwater flow controller failure (FWCF) (maximum demand)

b. generator load rejection with bypass failure (LRBPF)

The plant initial conditions are given in Table 15B.3-1. Nuclear conditions were consistent with the EOC conditions used for full power two-loop operation analysis to which this analysis is compared.

15B.3.1.1 Feedwater Controller Failure - Maximum Demand

This event is postulated on the basis of a single failure of a control device, specifically one which can directly cause an increase in coolant inventory by increasing the feedwater flow. The most severe applicable event is a feedwater controller failure to maximum flow demand. The feedwater controller is forced to its upper limit at the beginning of the event.

With excess feedwater flow, the water level rises to the high-level reference point at which time the feedwater pumps and the main turbine are tripped and a scram is initiated. Mitigation of pressure increase during the transient is accomplished by RPT and main bypass valves opening. Table 15B.3-2 lists the sequence of events. Figure 15B.3-2 shows the changes in important variables during this transient.

The computer model described in Reference 15B.8-2 was used to simulate this event. The GEMINI methodology given in GESTAR (Reference 15B.8-11) was used for MCPR evaluation.

The analysis has been performed with the plant conditions tabulated in Table 15B.3-1.

The SRV action is conservatively assumed to occur at 1 to 2 percent above the actual nominal setpoints. The transient is simulated by programming an upper limit failure in the feedwater system such that 132.5 percent of rated flow (nominal measurement of 127.5 percent at 1010 psig plus 5-percent variability allowance) occurs at 1010 psig. The temperature of the feedwater flow is conservatively assumed to be 400°F at rated power (rather than the nominal 420°F), and the initial water level is L4 (Low

Alarm). Credit is only taken for 16 of the 18 installed SRVs (the two valves with the lowest setpoints are assumed to be OOS).

Table 15B.3-4 provides a summary of the transient analysis results. The required operating limit MCPR (OLMCPR) is considerably less than the limit required at 60 percent of core flow based on the full-power two-loop analysis. The peak vessel pressure is below the full-power analysis results.

15B.3.1.2 Generator Load Rejection With Bypass Failure

Fast closure of the turbine control valves (TCVs) is initiated whenever electrical grid disturbances occur which result in significant loss of electrical load on the generator. The TCVs are required to close as rapidly as possible to prevent overspeed of the turbine-generator rotor. Closure of the main TCVs will increase system pressure. Mitigation of pressure increase during this transient is accomplished by the scram and RPT.

A loss of generator electrical load at 82 percent of original rated power and 60-percent flow under single recirculation loop operation produces the sequence of events listed in Table 15B.3-3. Figure 15B.3-3 shows the changes in important variables during this transient.

The computer model described in Reference 15B.8-2 was used to simulate this event. The GEMINI methodology given in GESTAR (Reference 15B.8-11) was used for MCPR evaluation.

The analysis has been performed with the plant conditions tabulated in Table 15B.3-1, except that the turbine bypass function is assumed to fail.

Table 15B.3-4 summarizes the transient analysis results. The required OLMCPR is considerably less than the limit required at 60-percent core flow based on the full-power two-loop analysis.

The peak vessel pressure is below the full power analysis results.

15B.3.1.3 EOC-RPT Out of Service

The analysis for SLO was performed for the two limiting transients, FWCF and LRBPF, with the plant conditions given in Table 15B.3-1, except that the EOC-RPT is assumed to be OOS. Nuclear conditions were consistent with the EOC conditions used for full-power two-loop operation analysis to which this analysis is compared.

Figures 15B.3-4 and 15B.3-5 show the changes in important variables during the transients.

Table 15B.3-5 gives a summary of the analysis results. The required OLMCPRs are considerably less than the limits required at 60-percent core flow based on the full-power two-loop analysis. The peak vessel pressures are below the full-power analysis results.

15B.3.1.4 Turbine Bypass Out of Service

The analysis for SLO was performed for the FWCF event with the plant conditions given in Table 15B.3-1, except that the turbine bypass is assumed to be OOS. Again, nuclear conditions were consistent with the EOC conditions used for full-power two-loop operation analysis to which this analysis is compared.

Figure 15B.3-6 shows the changes in important variables during the transient.

Table 15B.3-5 gives a summary of the analysis results. The required OLMCPRs are considerably less than the limits required at 60-percent core flow based on the full-power two-loop analysis. The peak vessel pressure is below the full-power analysis results.

15B.3.1.5 One MSIV Out of Service

The one MSIV OOS transient analysis results (Tables 15D-1 and 15D-2 in Appendix 15D) show that ΔCPRs for the limiting transients with the three steam line configuration are bounded by those for the standard configuration. Therefore, the OLMCPRs and K_f established for two-loop operation are also conservatively applicable to SLO concurrent with one MSIV OOS.

15B.3.1.6 Summary and Conclusions

The results show that for the transient events analyzed here both with and without the EOC-RPT and BP OOS options, the required OLMCPR is considerably less than the limit required by two-loop operation. It is concluded the OLMCPRs established for two-pump operation are also applicable to SLO conditions.

For pressurization, the results show that the peak pressures are below the full-power analysis results. Hence, it is concluded the pressure barrier integrity is maintained under SLO conditions.

15.B.3.2 Rod Withdrawal Error

The rod withdrawal error (RWE) at rated power is discussed in Section 15.4.2. These analyses are performed to demonstrate, even if the Operator ignores all instrument indications and the alarm which could occur during the course of the transient, the rod block system will stop rod withdrawal at a MCPR which is higher than the fuel cladding integrity safety limit. Modification of the rod block equation (below) assures the MCPR safety limit is not violated.

The APRM rod block system provides additional alarms and rod blocks when power levels are grossly exceeded. Modification of the APRM rod block equation (below) is required to maintain the two-loop rod block versus power relationship when in one-loop operation.

One-pump operation results in backflow through 10 of the 20 jet pumps while the flow is being supplied into the lower plenum from the 10 active jet pumps. Because of the backflow through the inactive jet pumps, the present rod block equation was conservatively modified for use during one-pump operation because the direct active-loop flow measurement may not indicate actual flow above about 38-percent core flow without correction.

A procedure has been established for correcting the APRM rod block equation to account for the discrepancy between actual flow and indicated flow in the active loop. This preserves the original relationship between APRM rod block and actual effective drive flow when operating with a single loop.

The two-pump rod block equation is:

$$RB = mW + RB_{100} - m(100)$$

The one-pump equation becomes:

$$RB = mW + RB_{100} - m(100) - m\Delta W$$

Where:

ΔW = difference between two-loop and single-loop effective drive flow at the same core flow. This value is expected to be 5 percent of rated (to be determined by the plant). This 5 percent difference is calculated into the single loop operation thermal power rod block setpoints.

RB = power at rod block in %

m = flow reference slope

W = drive flow in % of rated

RB_{100} = top level rod block at 100% flow

If the rod block setpoint (RB_{100}) is changed, the equation must be recalculated using the new value.

The APRM scram trip settings are flow biased in the same manner as the APRM rod block setting. Therefore, the APRM scram trip settings are subject to the same procedural changes as the rod block settings discussed above.

15B.3.3 Operating MCPR Limit

For SLO, the operating MCPR limit remains unchanged from the normal two-loop operation limit. Although the increased uncertainties in core total flow and TIP readings resulted in a 0.01 increase in MCPR fuel cladding integrity safety limit during SLO (Section 15B.2), the limiting transients have been analyzed to indicate that there is more than enough MCPR margin during SLO to compensate for this increase in safety limit. For SLO at off-rated conditions, the steady-state operating MCPR limit is established by the K_f curve. This ensures the 99.9-percent statistical limit requirement is always satisfied for any postulated abnormal operational occurrence. Since the maximum core flow runout during SLO is only about 60 percent of rated, the current flow-dependent K_f curve which is generated based on the flow runout up to rated core flow is also adequate to protect the flow runout events during SLO.

TABLE 15B.3-1

INPUT PARAMETERS AND ORIGINAL INITIAL CONDITIONS

1.	Thermal Power Level, MWt Analysis Value	 2725 (82% of 3323)
2.	Steam Flow, lb per hr Analysis Value	 11.35×10^6 (79%)
3.	Core Flow, lb per hr	65.10×10^6 (60%)
4.	Feedwater Flow Rate, lb per hr Analysis Value	 11.35×10^6 (79%)
5.	Feedwater Temperature, °F	400[(1)]
6.	Vessel Dome Pressure, psig	990
7.	Core Pressure, psig	997
8.	Turbine Bypass Capacity, % NBR	22.8
9.	Core Coolant Inlet Enthalpy, Btu per lb	 515
10.	Turbine Inlet Pressure, psig	971
11.	Fuel	GE8x8NB BP/P8x8R
12.	Core Average Gap Conductance, Btu/sec-ft^2-°F	GESTR axial distribution
13.	Core Bypass Flow, %	10.91
14.	Operating Limit MCPR @ 60% Core Flow Option A Option B	 1.49 1.44
15.	MCPR Safety Limit	1.08
16.	Doppler Coefficient ¢/°F	[(2)]
17.	Void Coefficient ¢/% Rated Voids	[(2)]

TABLE 15B.3-1 (Cont'd.)

18.	Core Average Rated Void Fraction, %	47.3
19.	Scram Reactivity, $ΔK	[2]
20.	CRD Speed Position Versus Time	Figure 15.0-3
21.	Jet Pump Ratio, M	3.16
22.	SRV Capacity, % NBR	
	@ 103% of 1159 psig	≥113.8
	Manufacturer	DIKKERS
	Quantity Installed	18(16)[3]
23.	Relief Function Delay, sec	0.4
24.	Relief Function Response Time Constant, sec	0.1
25.	Setpoints for SRVs	
	Safety Function, psig	1159, 1187, 1197, 1207, 1217
	Relief Function, psig	1106, 1116, 1126, 1136, 1146
26.	Number of Valve Groupings Simulated	
	Safety Function, No.	9[4]
	Relief Function, No.	9[4]
27.	High Flux Trip, % NBR	
	Analysis Setpoint (121 x 1.0)	121.0
28.	High-Pressure Scram Setpoint, psig	1071
29.	Vessel Level Trips, Feet Above Separator Skirt Bottom	
	Level 8 - (L8), Feet	6.175
	Level 4 - (L4), Feet	3.75
	Level 3 - (L3), Feet	1.75
	Level 2 - (L2), Feet	-3.708

TABLE 15B.3-1 (Cont'd.)

30.	APRM Thermal Trip Setpoint, % NBR @ 100% Core Flow (117 x 1.0)	117
31.	RPT Delay, sec	0.19
32.	Time Constant of Recirculation Pump - Motor, sec[5] Analysis Value	4.0-6.0
33.	Set Pressure of ATWS Recirculation Pump Trip, psig	1080
34.	Total Steam Line Volume, ft^3	4036

(1) The feedwater controller failure event was conservatively analyzed with feedwater temperature reduced by 20°F equivalent at rated power, and initial water level at L4 (low alarm).

(2) This value is calculated within the ODYN computer code (Reference 15B.8-2). Nuclear conditions were consistent with the EOC conditions used for full power two-loop operation analysis to which this analysis is compared.

(3) Two SRVs with the lowest setpoints are assumed inoperable.

(4) Two valves are simulated per group. For two SRVs OOS, eight groups are assumed to function.

(5) The inertia time constant is defined by the expression:

$$t = \frac{2nJ_o n}{gT_o}$$

where:

t = inertia time constant (sec)
J_o = pump motor inertia (lb-ft)
n = rated pump speed (rps)
g = gravitational constant (ft/sec^2)
T_o = pump shaft torque (ft-lb)

TABLE 15B.3-2

SEQUENCE OF EVENTS FOR FEEDWATER CONTROLLER FAILURE, MAXIMUM DEMAND (Figure 15B.3-2)

Time-sec	Event
0	Initiate simulated failure to the upper limit on feedwater flow.
11.8	L8 vessel level setpoint trips main turbine and feedwater pumps.
11.8	Reactor scram trip actuated from main turbine stop valve position switches.
11.8	RPT actuated by stop valve position switches.
11.9	Main turbine stop valves closed and turbine bypass valves start to open.
12.0	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
14.2	Relief valves actuated.

TABLE 15B.3-3

SEQUENCE OF EVENTS FOR GENERATOR LOAD REJECTION
WITH BYPASS FAILURE (Figure 15B.3-3)

Time-sec	Event
(-)0.015 (approx.)	Turbine generator detects loss of electrical load.
0	Turbine generator load rejection sensing devices trip to initiate TCV fast closure.
0	Turbine bypass valves fail to operate.
0	FCV closure initiates scram trip and RPT.
0.07	TCVs closed.
0.10	Turbine bypass valves should start to open - assumed to fail.
0.19	Recirculation pump motor circuit breakers open causing decrease in core flow to natural circulation.
	Group 1 relief valves assumed OOS.
1.2	Group 2 and 3 relief valves actuated.
1.2	Group 4 and 5 relief valves actuated.
1.3	Group 6 and 7 relief valves actuated.
1.4	Group 8 and 9 relief valves start to close.
>6	All relief valves are closed.

TABLE 15B.3-4

SUMMARY OF ORIGINAL TRANSIENT PEAK VALUE AND CPR RESULTS[1]

	LRBPF	FWCF
Initial Power/Flow (% rated)	82/60	82/60
Peak Neutron Flux (% NBR)	292	134
Peak Heat Flux (% rated)	96.2	89
Peak Dome Pressure (psig)	1154	1120
Peak Vessel Bottom Pressure (psig)	1171	1134
Required Initial MCPR Operating Limit at SLO Condition[2]:		
Option B	1.19	1.17
Option A	1.23	1.19
CPR Margin Between Two-Loop Limits and SLO Limits:		
Option B	0.19	0.21
Option A	0.20	0.24

(1) Cycle-specific information, including the effects of power uprate, is presented in Appendix A.

(2) Operating limits required at 60% core flow based on the full-power, two-loop analysis are 1.38 for Option B and 1.43 for Option A. The primary justification of SLO is based on the favorable comparison between these analyses, not the absolute values.

TABLE 15B.3-5

SUMMARY OF ORIGINAL TRANSIENT PEAK VALUES AND CPR RESULTS[1]
FOR SLO WITH EOC-RPT OOS AND BP OOS

	EOC-RPT OOS		BP OOS
	LRBPF	FWCF	FWCF
Initial Power/Flow (% rated)	82/60	82/60	82/60
Peak Neutron Flux (% NBR)	396	170	223
Peak Heat Flux (% rated)	103	93	96
Peak Dome Pressure (psig)[2]	1161	1123	1154
Peak Vessel Bottom Pressure (psig)	1174	1139	1171
Required MCPR Operating Limit at SLO Condition:[3]			
Option B	1.25	1.19	1.22
Option A	1.29	1.22	1.26
CPR Margin Between Two-Loop Limits and SLO Limits[3]			
Option B	0.21	0.27	0.24
Option A	0.21	0.28	0.24

(1) Cycle-specific information, including the effects of power uprate, is presented in Appendix A.

(2) The peak pressures are less than those calculated for the full-power, two-loop operation analysis (see Appendix A, Section A.15.0).

(3) Operating limits at 60% core flow based on full-power, two-loop analysis are 1.46 for Option B and 1.50 for Option A for EOC-RPT or turbine BP OOS. The required MCPR values were based on SLMCPR = 1.08.

15B.4 STABILITY ANALYSIS

15B.4.1 Phenomena

The primary contributing factors to the stability performance with one recirculation loop not in service are the power/flow ratio and the recirculation loop characteristics. At forced circulation with only one recirculation loop in operation, the reactor core stability is influenced by the inactive recirculation loop. As core flow increases in SLO, the inactive jet pump forward flow decreases because the driving head across the inactive jet pumps decreases with increasing core flow. The reduced flow in the inactive loop reduces the resistance that the recirculation loops impose on reactor core flow perturbations thereby adding a destabilizing effect. At the same time, the increased core flow results in a lower power/flow ratio which is a stabilizing effect. These two countering effects result in slightly decreased stability margin (higher decay ratio) initially as core flow is increased (from minimum) in SLO, and then an increase in stability margin (lower decay ratio) as core flow is increased further and reverse flow in the inactive loop is established.

As core flow is increased further during SLO and substantial reverse flow is established in the inactive loop, an increase in jet pump flow, core flow and neutron noise is observed. A cross flow is established in the annular downcomer region near the jet pump suction entrance caused by the reverse flow of the inactive recirculation loop. This cross flow interacts with the jet pump suction flow of the active recirculation loop and increases the jet pump flow noise. This effect increases the total core flow noise which tends to drive the neutron flux noise.

To determine if the increased noise is being caused by reduced stability margin as SLO core flow was increased, an evaluation was performed which phenomenologically accounts for SLO effects on stability, as summarized in Reference 15B.8-4. The model predictions were initially compared with test data and showed very good agreement for both two-loop and single-loop test conditions. An evaluation was performed to determine the effect of reverse flow on stability during SLO. With increasing reverse flow, SLO exhibited slightly lower decay ratios than two-loop operation. However, at core flow conditions with no reverse flow, SLO was slightly less stable. This is consistent with observed behavior in stability tests at operating BWRs (Reference 15B.8-5).

In addition to the above analyses, the cross flow established during reverse flow conditions was simulated analytically and shown to cause an increase in the individual and total jet pump flow noise, which is consistent with test data (Reference 15B.8-4). The results of these analyses and tests indicate that the stability characteristics are not significantly different from two-loop operation. At low core flow, SLO may be slightly less stable than two-loop operation but as core flow is increased and reverse flow is established the stability performance is similar. At even higher core flow with substantial reverse flow in the inactive recirculation loop, the effect of cross flow on the flow noise results in an increase in system noise (jet pump, core flow and neutron flux noise).

15B.4.2 Compliance to Stability Criteria

Cycle-specific evaluation is covered in Appendix A, Section A.4.4.4.

15B.5 LOSS-OF-COOLANT ACCIDENT ANALYSIS

If two recirculation loops are operating and a pipe break occurs in one of the two recirculation loops, the pump in the unbroken loop is assumed to immediately trip and begin to coast down. The decaying core flow due to the pump coastdown results in very effective heat transfer (nucleate boiling) during the initial phase of the blowdown. Typically, nucleate boiling will be sustained during the first 5 to 9 sec after the accident for the DBA.

If only one recirculation loop is operating, and the break occurs in the operating loop, continued core flow is provided only by natural circulation because the vessel is blowing down to the reactor containment through both sections of the broken loop. The core flow decreases more rapidly than in the two-loop operating case, and the departure from nucleate boiling for the high-power node might occur 1 or 2 sec after the postulated accident, resulting in more severe cladding heatup for the one-loop operating case.

In addition to changing the blowndown heat transfer characteristics, losing recirculation pump coastdown flow can also affect the system inventory and reflooding phenomena. Of particular interest are the changes in the high-power node uncovery and reflooding times, the system pressure, and the time of rated core spray for different break sizes. One-loop operation results in small changes in the high-power node uncovery times and times of rated spray. The effect of the reflooding times for various break sizes is also generally small.

Analyses of single recirculation loop operation using the models and assumptions documented in References 15B.8-10, 15B.8-11 and 15B.8-12 have been performed for Unit 2. Beginning with Cycle 4, the SAFER/GESTR methodology was used for the analysis of LOCA-single recirculation loop operation, and the analysis description is given in References 15B.8-12 and 15B.8-13. Using the methodology referenced in 15B.8-10, SAFE/REFLOOD computer code runs were made for the original Updated FSAR. The analysis was performed for a full spectrum of large break sizes for only the recirculation suction line breaks (most limiting for Unit 2). Because the reflood minus uncovery time for the single-loop analysis is similar to the two-loop analysis, the MAPLHGR curves were modified by derived reduction factors for use during one recirculation pump operation.

15B.5.1 Break Spectrum Analysis

SAFE/REFLOOD calculations were performed for the original analysis using assumptions given in Section II.A.7.3.1 of Reference 15B.8-10. Hot node uncovered time (time between uncovery and reflood) for SLO is compared to that for two-loop operation on Figure 15B.5-1.

The total uncovered time in the initial analysis for two-loop operation was 127 sec for the 100-percent DBA suction break. This is the most limiting break for two-loop operation. For SLO, the total uncovered time was also 127 sec for the 100-percent DBA suction break. This is the most limiting break for SLO. SAFER/GESTR analysis results are provided in References 15B.8-12 and 15B.8-13 for the largest break.

15B.5.2 Single-Loop MAPLHGR Determination

The small differences in uncovered time and reflood time for the original analysis of the limiting break size would result in a small change in the calculated peak cladding temperature (PCT). Therefore, as noted in Reference 15B.8-10, the one- and two-loop SAFE/REFLOOD results can be considered similar, and the generic alternate procedure described in Section II.A.7.4 of this reference was used in the original analysis to calculate the MAPLHGR reduction factors for SLO. The most limiting SLO MAPLHGR reduction factor (i.e., yielding the lowest MAPLHGR) is 0.81 for BP/P8x8R fuel, 0.79 for GE 8x8NB Reload 1 Cycle 2 fuel, and 0.78 for GE11, GE14, and GNF2 fuel. The most limiting SLO MAPLHGR reduction factor was reevaluated and updated using the SAFER/PRIME-LOCA methodology for the current cycle fuel. On the basis of analysis given in References 15B.8-12 and 15B.8-13, it was concluded that no MAPLHGR reduction factor is required for the current SLO (all licensing limits are met without any MAPLHGR reduction); however, the multipliers given here are conservatively maintained (Reference 15B.8-17).

15B.5.3 Small Break Peak Cladding Temperature

Section II.A.7.4.4.2 of Reference 15B.8-10 discusses the low sensitivity of the calculated PCT to the assumptions used in the original one-pump operation analysis and the duration of nucleate boiling. As this slight increase (~50°F) in PCT is overwhelmingly offset by the decreased MAPLHGR (equivalent to 300°F to 500°F PCT) for one-pump operation, the calculated PCT values for small breaks will be significantly below the 2200°F 10CFR50.46 cladding temperature limit. The conclusion also applies to the SAFER/GESTR-LOCA analysis in References 15B.8-12 and 15B.8-13 and the SAFER/PRIME-LOCA analysis in Reference 15B.8-17.

15B.5.4 Two ADS Valves and/or One MSIV Out of Service

It was shown in Section 15C.6 of Appendix 15C that two ADS valves OOS causes the maximum impact on the small break PCT. For the small break, the difference in PCT between one- and two-loop operation was relatively small in the original analysis compared to a large break as discussed in Reference 15B.8-10. As a slight increase in the small break PCT (20°F to 50°F) for SLO is overwhelmingly offset by the decreased MAPLHGR (the required reduction by a factor of 0.79 for the GE 8x8NB fuel is equivalent to about 300°F PCT) for SLO, the calculated limiting small break PCT for SLO with two ADS valves OOS (approximately 1770°F in the original analysis) is well below the PCT value presented in Section 15C.6 of Appendix 15C (and Appendix A, Section A.6, for cycle-specific reload analysis) for a small break with two ADS valves OOS for two-loop operation. This is significantly below the 2200°F 10CFR50.46 cladding temperature limit. This approach is also applicable to the SAFER/GESTR-LOCA analysis in References 15B.8-12 and 15B.8-13 and the SAFER/PRIME-LOCA analysis in Reference 15B.8-17. Therefore, the MAPLHGR reductions derived for each fuel type for SLO presented in Section 15B.5.2 also apply to SLO with two ADS valves OOS.

As discussed in Section 15D.6 of Appendix 15D, one MSIV OOS has no detrimental impact on LOCA. Therefore, the MAPLHGR reductions derived for SLO given in Section 15B.5.2 also apply to SLO with one MSIV OOS or SLO concurrent with two ADS valves OOS and one MSIV OOS.

15B.6 CONTAINMENT ANALYSIS

The analyses and evaluations described in this section were performed based on the original rated core thermal power of 3,323 MWt. The conclusions stated below have been reevaluated and found applicable for rated 3,467 MWt and 3,988 MWt operating conditions, as documented in Reference 15B.8-14 and 15B.8-16.

A SLO containment loss-of-coolant accident (LOCA) analysis was performed for Unit 2. The peak wetwell pressure, peak drywell pressure, dynamic loads due to chugging, condensation oscillation (CO) and pool swell were evaluated over the entire SLO power/flow region including into the MELLLA region.

The analysis shows that the peak LOCA drywell and wetwell pressures with SLO are 35.0 psig and 29.2 psig, respectively, and occur with a recirculation suction line break at the maximum vessel subcooling condition in the power/flow map. The corresponding differential peak drywell-to-wetwell pressure is 17.1 psid. The results, compared to the FSAR analysis (Section 6.2), and design values are presented in Table 15B.6-1. As noted from this table, the peak drywell and wetwell pressures with SLO are all bounded by the FSAR values and are substantially below the design limits. The peak drywell-to-wetwell pressure with SLO slightly exceeds the FSAR value; however, it remains substantially below the design value.

The containment dynamic loads evaluation was performed at the worst condition for the SLO and compared with those for the base case. Pool swell, CO, and chugging loads were assessed for the initial phase of a postulated recirculation line break. Additionally, SRV actuation loads were considered. It is concluded from the evaluation results that the current FSAR containment loadings bound the worst SLO loadings.

The bounding event for the drywell temperature response is a main steam line (MSL) break. Under SLO, the increased vessel subcooling has no impact on the steam break flow. However, the lower vessel pressure resulting from SLO reduces the steam break flow. It is concluded that the peak drywell temperature for SLO is bounded by that of the FSAR.

Finally, the peak suppression pool and wetwell airspace temperatures are governed by the long-term release of decay heat and energy removal by the residual heat removal (RHR) service water. Since the power levels for the SLO are bounded by that of the FSAR, it is therefore concluded that the peak suppression pool temperature is bounded by the peak suppression pool temperature given in the FSAR.

TABLE 15B.6-1

COMPARISON OF CONTAINMENT PEAK PRESSURES BASED ON ORIGINAL RATED CORE THERMAL POWER (3,323 MWt)[1]

	Base Case[2] (104.3% Power/ 100% Core Flow)	SLO (59% Power/ 35% Core Flow)	Design Limits
Peak Drywell Pressure, psig	39.75	35.0	45
Peak Drywell-To-Wetwell Delta P psid	16.89	17.1	25
Peak Wetwell Pressure, psig	33.98	29.2	45

(1) See Section 15B.6 regarding power uprate and EPU operation.

(2) NMP2 FSAR, Section 6.2, Table 6.2-4.

15B.7 MISCELLANEOUS IMPACT EVALUATION

15B.7.1 Anticipated Transient Without Scram Impact Evaluation

The principal difference between SLO and normal two-loop operation affecting ATWS performance is that of initial reactor conditions. Since the SLO initial power flow condition is less than the rated condition used for two-loop operation ATWS analysis, the transient response is less severe and, therefore, bounded by the two-loop operation analyses.

It is concluded that if an ATWS event were initiated at Unit 2 from the SLO conditions, the results would be less severe than if it were initiated from rated conditions.

15B.7.2 Fuel Mechanical Performance

The thermal and mechanical duty for the transients analyzed have been evaluated and found to be bounded by the fuel design bases.

It is observed that due to the substantial reverse flow established during SLO both the APRM noise and core plate differential pressure noise are slightly increased. An analysis has been carried out to determine that the APRM fluctuation should not exceed a flux amplitude of ±15 percent of rated and the core plate differential pressure fluctuation should not exceed 3.2 psi peak to peak to be consistent with the fuel rod and assembly design bases.

15B.7.3 Vessel Internal Vibration

A recirculation pump drive flow limit is imposed for SLO. The highest drive flow that meets acceptable vessel internal vibration criteria is the drive flow limit for SLO.

An assessment has been made for the expected reactor vibration level during SLO for Unit 2.

Before providing the results of the assessment, it is prudent to define the term "maximum flow" during balanced two-loop operation and SLO. Maximum flow for two-pump balanced operation is equal to rated volumetric core flow at normal reactor operating conditions. The steady state drive flow limit in SLO was determined during the startup test program at Unit 2 to be 41,800 gpm. In addition, full low testing performed at the BWRVIP/EPRI jet pump test facility with the slip joint clamps installed ensures no slip joint instability induced vibration for drive flows greater than the steady state flow limit of 41,800 gpm (Reference 9).

Startup tests at the Tokai-2 plant showed all components, including the in-core guide tube during SLO, to have vibration levels within acceptance limits. The Tokai-2 is the BWR 5/251 prototype plant. Since Unit 2 is not a prototype plant, there is no reactor internal vibration monitoring program. Instead, the data from the Tokai-2 plant is used for Unit 2 SLO assessment. Based on the Tokai-2 plant data, it can be inferred that the vibration levels of the reactor internal components for Unit 2 would be expected to be within acceptance limits during SLO with maximum flow as defined above.

For the jet pumps, the Unit 2 startup testing has yielded the required confirmation as Unit 2 jet pumps are instrumented. An analysis, using startup test data, has shown that no internals flow-induced vibration in excess of design limits occurs in either loop below 45,000 gpm loop drive flow. EPU analysis has determined no flow-induced vibration in excess of design occurs in either loop below 47,200 gpm loop drive flow.

In addition, testing of the replacement jet pumps installed in year 2012 has shown that the 45,000 gpm drive flow limitation for the recirculation pump operation due to reactor vessel internals (jet pumps) vibration may be removed and, consequently, drive flows up to two recirculation pump rated flow of 47,200 gpm are acceptable (Reference 8).

15B.8 REFERENCES

15B.8-1 "General Electric BWR Thermal Analysis Basis (GETAB); Data, Correlation, and Design Application," NEDO-10958-A, January 1977.

15B.8-2 "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," NEDO-24154, October 1978.

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15B.8-4 Letter, H. C. Pfefferlen (GE) to C. O. Thomas (NRC), "Submittal of Response to Stability Action Item from NRC Concerning Single-Loop Operation," September 1983.

15B.8-5 S. F. Chen and R. O. Niemi, "Vermont Yankee Cycle 8 Stability and Recirculation Pump Trip Test Report," General Electric Company, August 1982 (NEDE-25445, Proprietary Information).

15B.8-6 Deleted.

15B.8-7 Deleted.

15B.8-8 Deleted.

15B.8-9 Deleted.

15B.8-10 "General Electric Company Analytical Model for Loss-of-Coolant Analysis in Accordance with 10CFR50 Appendix K, Vol. III, Appendix A - One Recirculation Loop Out-of-Service," NEDO-20566-P-A, September 1986.

15B.8-11 GESTAR II, General Electric Standard Application for Reload Fuel, NEDE-24011-P-A-10-US, March 1991.

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15B.8-17 Nine Mile Point Unit 2 GNF2 ECCS-LOCA Evaluation, 002N4205-R0, December 2015.

APPENDIX 15C

TWO SAFETY/RELIEF VALVES OUT OF SERVICE

APPENDIX 15C

TWO SAFETY/RELIEF VALVES OUT OF SERVICE

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TWO SAFETY/RELIEF VALVES OUT OF SERVICE

15C.1 INTRODUCTION

Cycle-specific information is covered in Appendix A, Section A.15.

The Technical Specification 3/4 4.2 (prior to Amendment 91) requirement is that 16 of the total 18 safety/relief valves (SRVs) must be OPERABLE and, with one or more of the 16 SRVs inoperable, the action is to be in at least HOT SHUTDOWN within 12 hr and in COLD SHUTDOWN in the next 24 hr.

For the 7 SRVs which are part of the automatic depressurization system (ADS) Technical Specification 3/4 5.1 (prior to Amendment 91), the requirement is, with up to two valves inoperable, restore the valve(s) to OPERABLE status within 14 days or be in at least HOT SHUTDOWN within 12 hr and reduce reactor steam dome pressure to less than or equal to 100 psig within the next 24 hr.

This report contains technical justification to allow for extended plant operation with up to two SRVs out of service (OOS).

To justify extended plant operation with up to two SRVs OOS, a broad-based analysis of plant operating conditions is required. These analyses include the consideration of two SRVs OOS. The most limiting transient and overpressure protection events are evaluated with two SRVs OOS. This report covers the following areas:

1. Overpressure protection transient analysis,

2. Normal plant transient analysis, including operating critical power ratio (CPR) limit,

3. Anticipated transient without scram (ATWS) evaluation, and

4. Loss-of-coolant accident (LOCA) analysis.

15C.2 SUMMARY AND CONCLUSION

Based on the analyses described herein and in the reload analysis (Appendix A), it is concluded that extended plant operation at full power with up to two SRVs OOS meets all licensing requirements and, therefore, is acceptable for Nine Mile Point Nuclear Station - Unit 2 (Unit 2).

15C.3 OVERPRESSURE PROTECTION TRANSIENT ANALYSIS

Cycle-specific reload analyses are discussed in Appendix A, Section A.5.

In order to confirm that the remaining operating SRVs can maintain the vessel pressure below the ASME Code allowable limit of 1375 psig, an analysis of the most limiting overpressure transient (i.e., 3-sec closure of all main steam line isolation valves and neglecting the direct scram) is performed. The results are summarized on Figure 15C-1. Figure 15C-1 shows the peak vessel bottom pressure as a function of number of operating SRVs. It shows the peak vessel pressure with 2 of the 18 SRVs temporarily out of service is well below the ASME Code limit. Therefore, it is acceptable to operate the plant with 2 SRVs out of service at full power from the consideration of overpressure protection.

15C.4 NORMAL PLANT TRANSIENT ANALYSIS

Cycle-specific reload analyses are discussed in Appendix A, Section A.15.

In order to determine if there is any impact on the operating CPR limit due to two SRVs out of service, an assessment of the limiting transients performed for the Final Safety Analysis Report (FSAR) (Reference 1) was made. In all cases minimum critical power ratio (MCPR) occurs well before the first SRV opens. Therefore, up to two SRVs out of service will have no impact on the operating CPR limit. The only impact of two SRVs out of service on transient responses is peak pressures. However, these peak pressures are bounded by the case discussed in Section 15C.3 for ASME overpressure protection. The most limiting transient (i.e., load rejection with bypass valve failure) was reanalyzed with two SRVs out of service (see Figure 15C-9). This analysis confirms the above conclusion that the MCPR during this transient is not impacted by two SRVs out of service. The peak pressures for the case with two SRVs out of service are only about 4 psi higher than those with no SRV out of service, while the peak neutron flux, peak heat flux and MCPR are identical for both cases. Therefore, it is acceptable from the transient performance standpoint that the plant is operating at full power with 2 SRVs out of service.

The SRV operation has no significant effect on reactor core isolation cooling (RCIC) flow because it is a flow-sensing/flow-controlling system and the reactor pressure at the time of RCIC operation is not changed significantly by any two SRVs out of service. It has no effect on high-pressure core spray (HPCS) flow during operational events because of the unchanged reactor pressure when HPCS is needed. A small effect is seen in LOCA evaluations if the two out-of-service valves are ADS valves. This effect is considered in the analysis discussed in Section 15C.6.

15C.5 ATWS EVALUATION

An ATWS analysis was repeated for the Unit 2 plant with the assumption that two SRVs would be unavailable. This section compares the results of two SRVs unavailable to the published Unit 2 ATWS analysis of Reference 2 in order to demonstrate the impact of two SRVs out of service on adherence to the ATWS design criteria. The comparison is shown for ATWS analyses performed at original rated thermal power conditions 3,323 MWt).

From Reference 2, the Unit 2 ATWS main steam isolation valve (MSIV) closure event is shown to be the most limiting case in terms of the initial reactor pressurization. In this study, the two SRVs out of service have a direct impact on the plant capability to arrest this pressure rise and maintain reactor pressure within ASME Service Level C design limits of 1500 psig. The SRV availability studied here should have little or no impact on alternate rod insertion (ARI) or boron injection performance criteria.

Table 15C-1 shows the Unit 2 ATWS MSIV closure peak value results from Reference 2 and from this study (see Figure 15C-2). With the two SRVs unavailable, the initial pressure rise is shown to be less than 50 psi higher than reported in the base case. The peak vessel bottom pressure of 1279 psig is well within the Service Level C limit. The small differences in peak neutron and heat fluxes are of insignificant impact on reactor and core performance design criteria.

Table 15C-2 reports these same result comparisons for the Unit 2 ATWS turbine trip event (see Figure 15C-3). However, this event is not limiting in terms of pressure control nor core performance.

This study concludes that two SRVs out of service does not violate the ATWS design criteria for the Unit 2 plant. The study generically represents all licensed General Electric Company (GE) fuel types.

For operation at EPU (3,988 MWt) and Maximum Extended Load Line Limit Analysis Plus (MELLLA+) conditions, an ATWS analysis was performed for Unit 2 in References 5 and 6 with two SRVs out of service. From References 5 and 6, the ATWS main steam isolation valve (MSIV) closure event and pressure regulator failure – maximum steam demand (PRFO) event are the limiting ATWS events analyzed in terms of initial reactor pressurization. With two SRVs unavailable, the peak vessel bottom pressure of 1,372 psig is well within the ASME Service Level C design limit of 1,500 psig. Therefore two SRVs out of service does not violate the ATWS design criteria at EPU and MELLLA+ conditions for the Unit 2 plant.

15C.6 LOSS-OF-COOLANT ACCIDENT ANALYSES

Cycle-specific reload analyses are discussed in Appendix A, Section A.6.

For LOCA analyses, two SRVs out of service have only a minor impact on the calculated results unless they are valves which are associated with the ADS. As demonstrated in Section 6.3.3, for small breaks the unavailability of the HPCS system (as a result of the break or an assumed single failure) will result in the highest calculated peak cladding temperature (PCT). For these cases the emergency core cooling systems (ECCS) remaining include the ADS and some low-pressure ECCSs. Here the ADS is required to rapidly depressurize the vessel below the shutoff head of the low-pressure ECCS.

If two ADS valves are out of service in addition to the assumed worst single failure, the ADS will depressurize the vessel slower. This will result in a delay in low-pressure ECCS injection and, in general, a corresponding delay in reflooding time and increase in the PCT. However, the significance of the ADS decreases as larger break sizes are considered because of the increasing depressurization due to mass loss through the break. Therefore, the maximum impact on the PCT due to two ADS valves out of service will be determined by the recalculation of the small break spectrum.

Previous ADS out-of-service studies for Unit 2 and similar plants have shown that the HPCS line break with failure of the low-pressure core spray (LPCS) diesel generator will yield the highest small break PCT. Therefore, a break spectrum calculation was performed for this case in the original LOCA analysis for Unit 2, and the results are summarized on Figure 15C-4. For these original analyses, the Appendix K LOCA licensing models and assumptions given in Reference 1 were applied, except for the number of ADS valves out of service. From the original results it was determined that the maximum small break PCT is 2045°F occurring for a HPCS line break size of 0.11 ft^2. Reactor water level, vessel pressure, heat transfer coefficients and PCT versus time for this original analysis case are shown on Figures 15C-5 through 15C-8. Results of small break cases with two ADS valves out of service using the current SAFER/GESTR-LOCA methodology (Reference 3) are included in Appendix A. In all cases, the PCT is still below the 2200°F limit; no change in the operating maximum average planar linear heat generation rate (MAPLHGR) limits is required to meet the 10CFR50.46 licensing limits with two ADS valves out of service.

To verify that the HPCS line break is indeed the worst small break case, the small recirculation line break with the highest PCT (i.e., the 0.09 ft^2 break with HPCS failure) was reanalyzed using original analysis methods assuming two ADS valves out of service. The resulting PCT of 1650°F shows an increase of 128°F over the previous case. However, this case is clearly below the limiting HPCS line break cases (refer to Figure 15C-4).

The results of a main steam line break outside the containment would also be affected by the number of ADS valves available. For this case, closure of the main steam line isolation valves rapidly isolates the break. With failure of the HPCS, the impact of two ADS valves out of service will be similar to that described above for small breaks. In Section 6.3.3 the main steam line break outside the containment was originally analyzed with one ADS valve out of service resulting in a PCT of 955°F (586°F with SAFER/GESTR methods, Section 5.1.2 of Reference 4). An additional ADS valve out of service would increase the PCT by approximately 100°F. Therefore, the main steam line break outside the containment with two ADS valves out of service need not be specifically analyzed, since the PCT (approximately 1055°F based on the original analysis, less than 700°F using SAFER/GESTR) is several hundred degrees below the limiting case.

It is therefore concluded that an extended operation at full power with two SRVs out of service is acceptable from the consideration of ECCS performance.

15C.7 REFERENCES

1. General Electric Company, General Electric Company Analytical Model for Loss-of-Coolant Accident Analysis in Accordance with 10CFR50 Appendix K, NEDE-20566-P-A, September 1986.

2. NEDE-22013, "Design Analysis and SAR Inputs for ATWS Performance and Standby Liquid Control System, Nine Mile Point 2 Plant," June 1982.

3. GESTAR-II, General Electric Standard Application for Reload Fuel, NEDE-24011-P-A-21 and NEDE-24011-P-A-21-US, May 2015.

4. Nine Mile Point Nuclear Station - Unit 2 SAFER/GESTR-LOCA Loss-of-Coolant Accident Analysis, NEDC-31830P, Rev. 1, November 1990.

5. GE Hitachi Nuclear Energy, Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Constant Pressure Power Uprate, NEDC-33351P, May 2009.

6. Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Maximum Extended Load Line Limit Analysis Plus, NEDC-33576P, November 2013.

TABLE 15C-1

NMP2 ATWS MSIV CLOSURE EVENT

	Base Case NEDE-22013	Two SRVs Unavailable
Maximum Vessel Bottom Pressure	1245 psig	1279 psig
Maximum Steam Line Pressure	1209 psig	1249 psig
Maximum Neutron Flux	761% NBR	759% NBR
Maximum Average Surface Heat Flux	144% NBR	146.4% NBR

Table 15C-2

NMP2 ATWS TURBINE TRIP EVENT

	Base Case NEDE-22013	Two SRVs Unavailable
Maximum Vessel Bottom Pressure	1190 psig	1198 psig
Maximum Steam Line Pressure	1153 psig	1156 psig
Maximum Neutron Flux	550% NBR	583% NBR
Maximum Average Surface Heat Flux	118% NBR	121% NBR

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ONE MAIN STEAMLINE ISOLATION VALVE OUT OF SERVICE

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APPENDIX 15D

ONE MAIN STEAM LINE ISOLATION VALVE OUT OF SERVICE

15D.1 INTRODUCTION

Cycle-specific information is covered in Appendix A, Section A.15D.

When a main steam line isolation valve (MSIV) is declared out of service (OOS), it is closed and the plant steam flow and power are reduced to ≤75 percent of rated (if the plant is not immediately shut down to repair the MSIV). Power and steam flow are reduced to insure that steam flow in each of the active steam lines and the corresponding effect on reactor operating pressure do not exceed unit trip setpoints or the values assumed for the licensing analysis.

15D.2 REFERENCES

1. Final Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2.

2. NEDE-22013, Design Analysis and SAR Inputs for ATWS Performance and Standby Liquid Control System, Nine Mile Point 2 Plant, June 1982.

3. GESTAR-II, General Electric Standard Application for Reactor Fuel, NEDE-24011-P-A-9-US, September 1988.

4. Licensing Topical Report, Power Uprate Licensing Evaluation for Nine Mile Point Nuclear Power Station Unit 2, NEDC-31994P, Revision 1, May 1993.

5. SC02-13, 10 CFR Part 21 Notification, Main Steam Line Isolation Valve Out-Of-Service Safety Information Communication, September 30, 2002.

APPENDIX 15E

COMPLETE CORE OFF LOAD/RELOAD PROCEDURE GUIDELINES

APPENDIX 15E

COMPLETE CORE OFFLOAD/RELOAD PROCEDURE GUIDELINES

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COMPLETE CORE OFFLOAD/RELOAD PROCEDURE GUIDELINES

15E.1 INTRODUCTION

For extended plant outages, the complete offloading (and subsequent reloading) of the reactor fuel eliminates many of the constraints imposed by plant technical specifications on equipment operability and minimizes radiation exposure accumulations. Consequently, the degree of equipment maintenance and plant modifications that can be performed concurrently is increased with the core completely offloaded. In most cases, this improved flexibility during an outage more than offsets the additional time required for complete core offload/reload, resulting in a plant availability improvement.

Refueling interlocks are specified to reinforce operational procedures which prohibit fuel loading with any control rod withdrawn to prevent the potential of criticality excursions during the refueling operations. After fuel is removed from a control cell (defined as the four assemblies surrounding a control rod) or before a control rod is inserted in an unloaded cell, a double blade guide is inserted to support the control rod. Performing a complete core offload/reload, within the constraints of the existing system design, would therefore require a complete set of double blade guides. Storage of a complete set of blade guides (one double blade guide for each control rod; 185 for Nine Mile Point Nuclear Station - Unit 2 (Unit 2) is often impractical and, therefore, an alternative method for completely offloading and reloading the core is developed.

A safe method for core offloading and reloading with only a few double blade guides can be achieved by the use of spiral offloading/reloading patterns and the controlled use of bypasses to the refueling interlock system. Spiral offloading/reloading will always remove or load fuel at the periphery of the fueled region. While offloading the core, this will result in a continuous reduction of the core reactivity. During core loading using a spiral pattern, the fuel added will always be on the periphery with at least two water faces and, therefore, the reactivity addition from the loaded fuel will be minimized. This method of spiral loading/offloading has been approved by the Nuclear Regulatory Commission (NRC) (References 1 and 7) and is widely used in the nuclear industry.

A previous review of refueling interlock requirements identified a specific refueling event which could lead to an open-vessel criticality and significant fuel damage. Although it is an unlikely event, its probability of occurrence is calculated to be somewhat greater than 10^{-6} per reactor year, the threshold for defining a credible event. As a result, the General Electric

Company (GE) informed all boiling water reactor (BWR) owners of the event and recommended changes to the standard Technical Specifications that would procedurally prohibit the loading of fuel assemblies into the core with any control rod removed (Reference 2).

Plant Technical Specifications normally allow bypassing of the refueling interlocks to perform multiple control rod drive (CRD) and control rod maintenance. The practice of bypassing the refueling interlocks can be modified to allow a complete core offload/reload with only several blade guides. However, because of the potential consequences of an inadvertent criticality excursion during refueling operations as mentioned above, the procedures for bypassing the refueling interlocks must be strictly controlled. Bypassing of the refueling interlocks is considered acceptable during complete core offload/reload if the probability of a significant criticality event is less than the threshold for a credible event (10^{-6} per reactor year). Therefore, the core offload/reload guidelines are analyzed to determine the probability of such an event.

15E.2 SUMMARY

A set of guidelines has been established for the development of a procedure to completely offload and reload the core for Unit 2. These guidelines are applicable to both initial and reload cycles with GE-supplied fuel. The guidelines can be used to develop safe procedures for optimizing the complete core reloading and offloading process with either exposed or new fuel and a complete set of double blade guides or only several blade guides. These guidelines will be reflected in the Technical Specifications upon NRC approval.

A spiral offloading/reloading pattern is used to minimize the reactivity additions for each fuel assembly loaded during fuel loading and to assure that the core reactivity will continuously decrease during complete core offload. The spiral loading will begin adjacent to a source range monitor (SRM) to provide early indication of neutron flux levels in the reactor core. In addition, during initial core loading, the neutron sources will be loaded in their alternate locations which are adjacent (one control cell separation) to the SRM detectors to provide source-to-detector coupling after the initial four assemblies are loaded. Use of this "off-center" spiral loading between a SRM and the neutron source will also allow the elimination of fuel loading chambers (FLC), which are portable detectors typically used during the initial core loading.

Currently, refueling includes a complete offload and reload of the core using a full set of blade guides. The load pattern being used consists of loading four bundles around each SRM (to bring the SRMs on-line), and then a spiral reload starting at a SRM. The pattern for core offload is the reverse of the reload pattern (i.e., starting at the periphery and unloading in a spiral pattern inward to a SRM, the four bundles around each SRM are offloaded last). The procedures provide a contingency for the case of a failed SRM. Additionally, when all control rods are inserted, the RPS will be in a coincident configuration (i.e., RPS shorting links installed). In order to ensure all rods remain fully inserted during reload activities, administrative controls are established on the use of the control rod withdrawal push button after all rods have been verified to be fully inserted.

The core offload and reload procedures and the refuel manual have been reviewed and are consistent with NSAC/164L, Guidelines for BWR Reactivity Control During Refueling.

To allow the complete core offload/reload without the use of a complete set of double blade guides, guidelines have also been provided for the controlled bypassing of the refueling interlock logic and the SRMs. These guidelines have been reviewed to determine their compatibility with earlier GE recommendations for fuel loading (Reference 2). A probabilistic analysis of the complete core offload/reload sequence based on the guidelines developed has been performed to determine the probability of the criticality excursion defined in Reference 2. The results demonstrate that the probability of such an event is very low for cores containing GE fuel (<10-8 per reactor year) and, therefore, the incorporation and adherence to the guidelines in an offload/reload procedure will provide adequate assurance of safe operation throughout the complete core offload/reload process.

For the initial core loading, the Technical Specifications are modified by adding a special test exception which incorporates the necessary monitoring requirements that are unique to the initial core loading.

15E.3 PROCEDURE GUIDELINES

The following sections provide a summary of the major steps in the guidelines with applicable justifications for critical steps in the offload/reload process. Section 15E.3.4 is included to specifically address the unique features of an initial core loading.

15E.3.1 Complete Core Offload Procedure Guideline

A complete core offload procedure provides step-by-step instructions to perform a complete core offload operation from a fully loaded core, with a fixed set of double blade guides. The offload starts from the periphery of the core and works its way inward in U-shaped blocks. An offload sequence map is shown on Figure 15E.3-1. With this method, no water gaps among fueled regions will be created as flux trap areas, thus eliminating an inadvertent criticality accident caused by an assembly dropping into such areas and assuring a continuous decrease in core reactivity. The important safety measures in this guideline are the verification of major steps and independent Quality Assurance (QA) checks between the fuel removal from the control cell and subsequent control rod withdrawal. The entire core offload operation is performed in batches. Each batch of operation consists of fuel removal from a fixed number of control cells, which is called the batch size. The batch size depends on the number of double blade guides available for use.

After the refueling platform operation prerequisite checks, the control room Operator checks for SRM operability, and verifies the use of the same worksheet with the bridge Operator. Fuel offloading is then performed starting from the outmost peripheral cell. The offloading is repeated until a fixed number of control cells of fuel are removed, with double blade guides installed in these cells. This number is called the batch size, which is equal to the number of available double blade guides. At this time, an independent QA check is performed to verify that all fuel assemblies have been removed from these cells and double blade guides have been installed. After this check, the following operational steps are performed on each individual control rod in the batch. First the control room Operator withdraws the control rod to the full-out position. After verification of rod position, either the instrumentation Technician electrically disarms the insert directional control valves on the hydraulic control unit (HCU) of this rod or the equipment Operator closes the designated HCU valves to prevent inadvertent movement of the control rod.

Up to this point, true position indication of this control rod is still available on the four-rod display panel. In the next major step, the individual rod position input to the refueling interlock logic of this rod is bypassed, based on separate bypass guidelines. After the completion of control rod withdrawal and bypass steps for all the control rods in this batch, the offload operation for this particular batch is then completed. Another independent QA check is performed to verify correct bypass status and other offload records. The same offload procedure is then repeated for the offloading of the next batch, until the entire core is offloaded. During the offload process whenever any SRM reading drops below the minimum required count rate because of fuel removal, the SRM/intermediate range monitor (IRM) downscale rod block signal is bypassed according to the SRM/IRM bypass guideline.

As stated earlier, the verification check is one of the most important steps in this guideline. On the refueling bridge, there are two designated checkers in addition to the bridge Operator, one being the Senior Reactor Operator (SRO), the other a designated bridge checker. In the control room, both the first control room Operator and the second control room Operator will serve as verifiers. For both the local equipment Operator at the HCU station and the instrumentation Technician at the refueling interlock bypass panel, a second assistant Operator/Technician is desirable but not required by the guideline. Finally, there is the designated QA checker who will perform all independent QA checks required by the guideline.

The batch size is governed by the number of available double blade guides. This number of blade guides is from 2 to 15, with the latter estimated to be the maximum number of control cells any single shift can offload. With a larger batch size, there will be increased time savings in bypass operations and QA checks because of improved efficiency.

This guideline provides an offload scheme that fully utilizes the monitoring capability of the SRMs. Instead of using spiral offloading to reach the core geometrical center, the spiral offloading scheme is established such that there will be at least one SRM which is constantly and continuously monitoring the fueled region. Since reactivity is continuously removed from the core because of fuel offload, and no fuel assembly is allowed to be moved into the core under any circumstance, under normal conditions the neutron flux will continually decrease. Consequently, it is permitted to allow SRM readings to go below the minimum required count rate during the offload process.

15E.3.2 Complete Core Reload Procedure Guideline

The complete core reload procedure provides step-by-step instructions to perform complete core reload operations from a fully offloaded core. Unlike conventional types of core reload, all control rods will have been fully withdrawn from the core, with the rod position input to the refueling interlock logic bypassed during core offload of the previous fuel cycle. When fuel loading is in progress with control rods withdrawn from the core, the RPS will be in a noncoincident mode (i.e., RPS shorting links removed). Technical Requirements Manual (TRM) Section 3.3.1.2 provides criteria for the shorting links. The reload operation starts from a cell location near a SRM detector and works its way out in U-shaped loading blocks. A recommended loading sequence map is shown on Figure 15E.3-2. Similar to the core offload operation (Section 15E.3.1), the important safety measures in this guideline are the verification of major steps and the independent QA check between the control rod insertion with bypass removed and the actual fuel loading. The entire reload is performed in batches, with the batch size equal to the number of available double blade guides. These guidelines are also applicable to initial core loading, with several exceptions. The unique features of an initial core loading are described in Section 15E.3.4.

After the refueling platform operation prerequisite checks, the control room Operator checks the operability of the SRMs, using a special movable neutron source, and verifies the use of the same worksheet with the bridge Operator. The next several steps involve the operation on one control cell, namely the installation of a double blade guide in this cell, the bypass removal of the rod position input to the refueling interlock, the activation of the HCU system for the control rod, control rod coupling check and, finally, the insertion of the control rod to the full-in position, followed by refueling interlock functional check. The guideline to perform bypass removal of individual rod position inputs is provided as a separate guideline (Section 15E.3.3.1). After the completion of these steps on one control rod, the same operation is repeated for the remaining control cells in the batch. After the above operations are completed for the whole batch, an independent QA check is performed to verify that within this batch all rod position refueling interlock bypasses are removed and all control rods are fully inserted. Fuel assemblies are then loaded into control cells of this batch, with the double blade guides moved to cell locations of the next batch as the fuel assemblies are loaded. This completes the reload procedure for one batch. Finally, the same reload procedure is repeated for the loading of the next batch, until the entire core is loaded.

The same number of operation staff members are required in the reload operation as in the offload operation. In the control room, both control room Operators will serve as verifiers. On the refueling bridge, there are the bridge Operator, the SRO, and the bridge checker, the latter two serving as verifiers. The staffing requirements at HCU station and refueling interlock bypass panel are the same as in the offload operation. An independent QA checker is to be designated to perform all the QA checks required by this guideline.

Similar to the offload guideline, the batch size can be any number from 2 to 15, depending on the total number of available double blade guides. As determined by the probability analysis to be discussed later, the above identified batch size range will not significantly affect the probability of creating inadvertent criticality events.

Instead of loading initially from the geometrical center of the core, the loading starts at a location near a SRM. By doing so, a SRM can be brought on scale as early as possible in the reload operation to continuously monitor the fueled region. Throughout the entire reload operation, there is at least one SRM which is continuously monitoring the fueled region (except for the loading of the first 4 bundles), with at least one additional SRM operable.

15E.3.3 Refueling Interlock Logic Bypass Guidelines

15E.3.3.1 Individual Rod Position Bypass Guideline

The individual rod position bypass procedure should provide step-by-step instructions for the bypass or bypass removal of the individual rod position input signals to the refuel interlock logic during core offload or reload operations. During offload operation, since all control rods are to be withdrawn, it is necessary to bypass the individual rod position input to the refueling interlock logic to bypass the "one-rod-out" rod block logic. The refueling interlock logic from all other control rods, however, shall remain in effect to prevent any erroneous rod withdrawals. During reload operation, the bypass of the rod position input must be removed before a control rod is fully inserted such that full position indication of the rod is available. This guideline is to be used in conjunction with the core offload or reload procedure guidelines.

The bypass of the rod position input to the refueling interlocks is to be performed during core offload operations. This guideline is called upon at the designated step in the core offload guideline. Before the bypassing, the Control Room Operator must verify that the control rod is fully withdrawn. As soon as the rod position inputs are temporarily disconnected from the bypassing panel, the Control Room Operator must verify a loss of indication on the four-rod display panel. The bypass is then performed by shorting the two pins which will simulate a "Full-In" position signal to the refueling interlock logic. The Control Room Operator then verifies that the light indication on the rod display panel has changed to a "Full-In" green. This light is then tagged to remind the Control Room Operator of the bypassing. A second Control Room Operator then verifies this step.

During core reload, the bypass of the rod position input to the refueling interlock logic is to be removed prior to the insertion of a control rod. This guideline is called upon at the designated step in the core reload guideline. The Control Room Operator first verifies that the correct rod is selected. He then removes the bypass tag and verifies the "Full-In" green light is displayed. The instrumentation technician then removes the bypass from the designated connector. During and after the removal of the bypass from the two pins, the appropriate light indications are verified. The "Full-Out" red light shall be on after the bypass removal. A second Control Room Operator then verifies these steps. For both bypass and bypass removal operations, the Control Room Operator and Shift Manager (SM) shall keep up-to-date inventory of all unused jumpers. An important consideration in this guideline is that the bypass of a rod position signal is always performed after all operations on this rod have been completed, including the HCU valving, and the bypass removal is always performed prior to all operations being performed on this rod. This will fully utilize the position indication of the rod and minimize chances for error.

There are several cable panel locations throughout the rod position indication probe cable routing where the bypass (and bypass removal) can be performed, namely at the undervessel location, at the drywell penetration panel, and on panel 615 inside the control room. Each location has its merits and disadvantages. The most desirable location is probably on panel 615 inside the control room. However, some cable connection modifications would have to be implemented before the individual rod position bypass can be done on panel 615.

15E.3.3.2 SRM/IRM Rod Block Input Bypass Guideline

The SRM and IRM provide inputs to the refueling interlock logic, namely the SRM/IRM downscale rod block signal input. Whenever the reading of a SRM (or IRM) goes below the required minimum count rate, all control rods are blocked from being withdrawn. However, during core offload, all SRMs will eventually drop below the minimum required count rate. It is thus necessary to bypass such input to the refueling interlocks to continue the offload operation smoothly.

The bypassing of individual SRM channels is performed during core offload when a SRM drops below the minimum required count rate. The bypass location is inside the neutron monitoring system (NMS) cabinet on the trip auxiliary unit. The K2 relay in the trip auxiliary unit is normally closed when the associated SRM is on scale. The relay will be open when SRM is downscale, thus initiating a rod block. The bypass is performed by shunting the K2 relay, with the relay itself electrically disconnected from the circuit, such that a simulated "closed" relay is permanently in effect until the bypass is removed. SRM upscale rod block, SRM inoperable rod block, and the SRM upscale trip (scram) are still in effect.

15E.3.4 Initial Core Loading Guidelines

The guidelines for complete core reload have also been developed to be applicable to initial core loading. Several unique features of initial core loadings must be addressed. The initial core loading is part of the startup testing described in Chapter 14 and is controlled by the requirements of Regulatory Guide (RG) 1.68. RG 1.68 (Revision 2, August 1978), Appendix A, paragraph 2, establishes requirements for initial fuel loading to prevent inadvertent criticality. Requirements for continuous monitoring of the neutron flux throughout the core loading must be established. In addition, paragraph 2.a requires that the shutdown margin be verified for a partially and fully loaded core.

Test Number 3, Fuel Loading, provides the procedures to load fuel safely and efficiently to the full core size, and includes shutdown margin verification (including Test Number 4 - Full Core Shutdown Margin).

Historically, FLCs have been used to measure the neutron count rate during initial fuel loading because of their high sensitivity and ability to be moved near initial fuel loading locations and neutron sources. With a complete set of blade guides and the complete core reload guidelines, it is possible to simplify the fuel loading procedure by replacing the FLCs with the SRM instrumentation. In addition, the startup neutron sources would be positioned in their alternate locations (to be closer to the SRM detectors) and the fuel loading sequence would begin between a SRM detector and a neutron source. The number of neutron sources will also be reduced from seven to four. Fuel loading would continue in a spiral pattern around the initial SRM until the core is fully loaded (Figure 15E.3-3).

Requirements during fuel loading are established to preclude inadvertent criticality. A thorough prefuel loading checklist is performed to verify that all systems required during fuel loading are operable. Prior to initial core fuel loading, all control rods are verified to be fully inserted and remain fully inserted throughout the proposed fuel loading, except during the partial core shutdown margin test at which time rod movement is controlled by strict procedural guidance. No control rod movement will be performed until the minimum count rate is achieved on at least one SRM.

Predictions of the core reactivity and shutdown margin have been prepared in advance for Unit 2 fuel design and support the safe fuel loading under subcritical conditions. For the initial fuel loading, it has been predicted that the effective neutron multiplication factor for a fully-loaded core with all rods inserted is 0.93, and is 0.97 with the strongest worth control rod withdrawn (cold conditions). These predictions have been performed with core physics calculation methods that have been extensively qualified against tests/experiments, benchmark calculations and shutdown margin demonstration tests for initial and reload cores (Reference 3).

In addition, rigorous QA programs during fuel design and fuel and control rod manufacturing ensure that the fuel and control rods are manufactured as specified. These QA programs (described in Reference 4) apply quality system elements necessary to provide assurance that systems and components meet the quality requirements of applicable codes, standards and regulatory agency requirements. GE's QA program has been reviewed by the NRC and found to comply with all applicable requirements of Appendix B to 10CFR50 (Reference 5). As a result, these prefuel loading precautions and measures provide additional assurance against inadvertent criticality during initial fuel loading.

For the spiral fuel loading, the fuel will be initially loaded between a source at its alternate location and the closest SRM. Figure 15E.3-3 shows the initial core fuel loading sequence. Because of the fixed location of the SRMs and the distance from the sources, the SRM count rate will initially be less than the plant Technical Specification minimum SRM count rate. As fuel is loaded, neutronic coupling between the source and detector will occur and the count rate will increase. The estimated minimum SRM count rate with 16 assemblies loaded as a function of the source strength has been determined based on past BWR startup test results from seven plants using FLCs. SRM count rates were also available for one of the seven plants. The results are presented in Figure 15E.3-4. Figure 15E.3-4 shows that, with appropriate conservatisms, a source strength of 500 curies is required to assure that the minimum count rate of 0.7 cps is achieved with the initial 16 assemblies loaded. The SRM data, for a startup where the alternate source location was used (source strength of 1855 curies), indicated a SRM count rate of 12 cps with six assemblies loaded and 30 cps with 16 assemblies loaded. Unit 2 uses Californium-252 neutron sources with an equivalent Sb-Be source strength of 2000 curies. Because of the source strength and fission source spectrum (higher neutron energy than the standard Sb-Be source) of the CF-252 source, it is expected that the minimum SRM count rate will be achieved before 16 assemblies are loaded. Nevertheless, an exemption to the requirement for a minimum count rate (0.7 cps) during the loading of the initial 16 assemblies is provided in Technical Specification 3/4.10.7.

To further support this exemption, a core reactivity calculation was performed for the initial 16 assemblies loaded to demonstrate that even with all of the control rods withdrawn, the partial loading would remain subcritical with margin. The fuel assembly types and loading configuration of the 16 assemblies were based on the fuel loading procedure of Figure 15E.3-3 and are shown on Figure 15E.3-5. For a moderator temperature of 20°C, the resulting effective neutron multiplication factor was 0.99. This analysis demonstrates that the initial 16 assembly loading will remain subcritical by 1.0 percent ΔK even if the control rods are withdrawn, thus further assuring that the SRM monitoring requirements can be exempted during this portion of the fuel loading procedure. Similar exemptions of SRM monitoring requirements (for fewer assemblies) during fuel loading have been approved by the NRC for several reload licenses (References 1, 6, and 7).

After the initial 16 assemblies are loaded and a SRM is on scale, the fuel loading will continue in a spiral fashion as shown on Figure 15E.3-3. Since only one SRM will initially be on scale, a portable source will be used to periodically demonstrate operability of the SRMs located in areas with no fuel. One of the SRMs will be required to maintain continuous visual indication in the control room until other SRMs are on scale. Use of a portable source to demonstrate operability of the remaining SRMs has previously been approved by the NRC for other plants (References 1 and 7). The portable source is widely used in the nuclear industry as a bugging source for detector calibration and is an easy device to operate with no complex or unsafe maneuvers required.

When 142 fuel assemblies have been loaded (Step 37 on Figure 15E.3-3), a SRM will be surrounded by fuel and indicating greater than 0.7 cps. At this time, a partial core shutdown margin test will be performed as required by RG 1.68. Core physics calculations for the off-center partial shutdown margin test have been performed for the fuel loading sequence (Reference 8). After the partial core shutdown margin test, the remaining fuel will be loaded based on the sequence shown on Figure 15E.3-3 until the core is fully loaded. During this portion of the fuel loading, at lease two SRMs will be operable, with at least one providing continuous visual indication in the control room. SRMs not surrounded by fuel will be periodically checked for operability using the portable source. Once the core is fully loaded, the full core shutdown margin test will be performed using the standard procedures.

15E.4 PROBABILISTIC ANALYSIS

A previous review of refueling interlock bypass practices identified a specific refueling event which could lead to an open-vessel criticality and significant fuel damage. The event is the result of loading two adjacent uncontrolled cells (eight assemblies) resulting in a criticality excursion. During the loading of the last assembly, assumed to be loaded at the maximum grapple insertion speed, a significant reactivity excursion occurs. Although the event was determined to be unlikely, its probability of occurrence was calculated to be somewhat greater than 10^{-6} per reactor year, the threshold for defining a credible event. As a result, GE informed all BWR owners of the postulated event and recommended changes to the standard Technical Specifications that would procedurally prohibit the loading of fuel assemblies into the core with any control rod removed (Reference 2).

Because of the requirement to bypass individual refueling interlocks during the complete core offload/reload process, an analysis was performed to determine the probability of creating two adjacent loaded uncontrolled cells based on the procedure guidelines outlined in Section 15E.3. The probability of occurrence, while following the reloading procedures, is approximately 10^{-9} per refueling for cores with GE fuel. Because of the spiral loading pattern, the probability of the two adjacent cells becoming critical while loading the last assembly is extremely small and, therefore, the total probability is well within the goal of 10^{-6} per reactor year.

15E.4.1 Methodology

An inadvertent criticality is caused by the creation of two interior adjacent loaded uncontrolled fuel cells (LUFC) during fuel loading. A LUFC is a control cell with four fuel assemblies loaded, without a control rod inserted in the cell. To create the first LUFC, the Operator can either load an uncontrolled fuel cell (UFC), or withdraw a control rod from a loaded fuel cell (LFC). The second LUFC can be created in the next cell within the same batch, or in the next outer cell during a later batch. However, the event resulting from the withdrawal of the control rod from a second LFC will be terminated by a reactor scram. This event is the Continuous Control Rod Withdrawal Transient in the Startup Range that has been previously analyzed for GE fuel (Reference 9) and, therefore, is not considered in this analysis.

A fault tree has been constructed with the top event being the creation of two adjacent LUFCs during the loading of one batch. Human error models were taken from NUREG-CR/2254. Human error dependency is an important factor to be considered in determining the number of cells that should be loaded per batch. Table 15E.4-1 shows the correlation of human errors.

The probability of two LUFCs being next to each other was also considered and assumed to be of the following relation:

$$\text{Probability (per batch)} = \frac{\text{Unacceptable Combinations}}{\text{Total \# of Combinations}}$$

which is calculated to be equal to 2/n, where n = number of cells per batch. It was found that the probability of creating two adjacent LUFCs per batch decreased as the number of cells in a batch increased. This is consistent with the expected results if one batch included the entire core. In this case, all of the control rods would be inserted prior to loading any fuel since a complete set of blade guides would be required. Any reduction in the number of cells per batch would require that some control rods not be inserted during fuel loading, thereby increasing the probability of a LUFC.

The most significant contributors to the event of creating two adjacent LUFCs are:

<u>Creation of First LUFC</u>

1. Failure to remove bypass of refueling interlock (first cell)

2. QA failure to detect error in step 1

3. Failure to insert control rod (first cell)

4. QA failure to detect error in step 3

<u>Creation of Second LUFC</u>

5. Failure to remove bypass of refueling interlock (second cell)

6. QA failure to detect error in step 5

7. Failure to insert control rod (second cell)

8. QA failure to detect error in step 7

9. Second cell adjacent to first cell (same batch)

There are many other possible combinations, but most of them are not considered important because the probability is too low (10^{-15}) to be considered. In addition, the complete core offloading process using the guidelines in Section 15E.3 was studied. It was estimated that this was an inherently safer procedure than the reloading procedure since fuel is always being removed during the process. Therefore, its contribution was assumed to be negligible when added to the complete core reload procedure probability.

15E.4.2 Fault Tree Quantitative Analysis

A simulation of the refueling process was performed using fault trees to determine the probability of creating two adjacent LUFCs for varying numbers of cells loaded per batch. Some events were neglected in the analysis, based on their extremely low probability. For instance, a second LUFC could be created in the next outer batch, which could then be adjacent to a LUFC in the inner batch (Figure 15E.4-1). However, during spiral refueling, this event has a relatively low probability (10^{-10}) because of the independence of the batches.

Based on the fault tree analysis, the probability of occurrence of creating two adjacent LUFCs during complete core reloading following these guidelines was found to be 10^{-8} to 10^{-9} per refueling for batch sizes of 2 to 15 cells for cores with GE fuel. Since this probability was calculated using conservative assumptions, and the probability of two adjacent LUFCs loaded on the periphery resulting in a significant criticality excursion is small, it is concluded that the goal of 10^{-6} per reactor year is met by these guidelines.

TABLE 15E.4-1

HUMAN ERROR DEPENDENCY

First Error	Second Error	Dependency
Error 1	Same error in same batch	High
Error 2	Same error in different batch	Independent
QA Error (checking)	Similar error in same batch	Low
QA Error (checking)	Same error in same batch	High

15E.5 REFERENCES

1. Amendment No. 27 to Facility Operating License No. DPR-63, Niagara Mohawk Power Corporation, Nine Mile Point Unit No. 1, Docket No. 50-220, March 2, 1979.

2. "Recommended Technical Specifications For Fuel Loading," Service Information Letter No. 372, General Electric Company, June 1982.

3. "Steady State Nuclear Methods," General Electric Company Licensing Topical Report, May 1985 (NEDO-30130-A).

4. "Nuclear Energy Business Operation Quality Assurance Program Description," General Electric Company, March 1985 (NEDO-11209, Revision 5).

5. Letter, G. G. Zech (NRC) to J. M. Case (GE), "NRC Acceptance of Revised General Electric Quality Assurance Topical Report," April 19, 1985.

6. Amendment No. 66 to Facility Operating License No. DPR-57, Georgia Power Co. et al, Edwin I. Hatch Nuclear Station Unit No. 1, Docket No. 50-321, June 12, 1979.

7. Amendment No. 5 to Facility Operating License No. NPF-29, Grand Gulf Nuclear Station Unit No. 1, Docket No. 50-416, October 12, 1985.

8. Startup Data Databook, General Electric Company, January 1986 (23A1840, Rev. 1).

9. J. F. Klapproth, "Continuous Control Rod Withdrawal Transient in the Startup Range," General Electric Company, April 1978 (NEDO-23842).

APPENDIX 15F

THIS APPENDIX WILL BE SUBMITTED IN A FUTURE UPDATE.

APPENDIX 15G

MAXIMUM EXTENDED LOAD LINE LIMIT ANALYSIS PLUS OPERATION

APPENDIX 15G

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MAXIMUM EXTENDED LOAD LINE LIMIT ANALYSIS PLUS OPERATION

15G.1 INTRODUCTION AND SUMMARY

The operation flexibility during power ascension from the low-power/low-core-flow condition to the high-power/high-core-flow condition is limited by two factors. First, if the rated load line control rod pattern is maintained as core flow is increased, changing equilibrium xenon concentrations will result in less than rated power at rated core flow. Second, fuel pellet-cladding interaction considerations (for nonbarrier fuel types) inhibit reactivity compensation through control rod withdrawals at high power levels; thus the reactivity compensation for changing xenon concentrations may be outside the preconditioning interim operating management recommendations (PCIOMRs). The combination of these two factors can cause difficulty in attaining rated core power.

These limitations can be overcome by allowing operation with a rod pattern that requires fewer adjustments when ascending to full power. This requires an expansion of the power/flow map to allow operation above the rated load line. The operating envelope is modified to include the extended operation region bounded by points D-N-M-L-C-D as shown in Chapter 15, Figure 15.0-2a. This region is defined as MELLLA+ region/domain. The expansion of the power/flow map allows operation at 100 percent rated power with core flow as low as 85 percent rated flow.

The analysis contained in References 18 and 19 is referred to as the MELLLA+ analysis. The MELLLA+ modification is implemented in middle of Cycle 15. The limiting transient events at MELLLA+ condition for subsequent cycles are reanalyzed to confirm that the operating limits are still bounding.

The results of the analysis show that the licensing basis (100P, 105F) operating limits remain bounding for operation within the MELLLA+ region.

The analysis also confirms that operation in the MELLLA+ region is within allowable design limits for vessel overpressure protection, core stability, post-LOCA emergency core cooling system (ECCS) performance, post-LOCA containment response, anticipated transient without scram (ATWS) events, reactor internals integrity, steam dryer and separator performance, and high-energy line break (HELB) events.

15G.2 TRANSIENT EVENT EVALUATION

Cycle-specific reload analyses are discussed in Appendix A, Section A.15.

15G.2.1 Analytical Basis

The standard power/flow map is described in Section 4.4.3.3. A modified power/flow curve has been derived to provide relief from the operating restrictions inherently imposed during ascension to power by the existing power/flow curve. Four design basis objectives were specified in deriving this operating curve:

1. For those transients and accidents that are sensitive to variations in power and flow, the licensing basis point must be shown to be a more limiting condition than any condition within the MELLLA region. Otherwise, revised operating limits for the MELLLA region must be defined.

2. In no instance shall the ratio of power to flow intentionally exceed the ratio defined by the rod line which passes through the 100 percent of current licensed thermal power and 85 percent of rated core flow (RCF) point (MELLLA+ upper boundary line).

3. The slope of the MELLLA+ upper boundary line must be such that flow increases are capable of compensating for xenon buildup while increasing reactor power to rated power at rated core flow.

4. The consequences of all accidents and transients currently in the licensing basis must remain within the limits normally specified for such events.

15G.2.2 Operating Transients

The operating transients that define the operating limit critical power ratio (CPR) envelope were reevaluated to show that the fuel safety limit will be met in the MELLLA+ region. These transients are the loss of feedwater heating (LFWH), feedwater controller failure (FWCF), load rejection with no bypass (LRBPF), and turbine trip with no bypass (TTBPF). These limiting transients were analyzed at the MELLLA+ 100-percent power intercept point (100P, 85F) to confirm the MELLLA+ operating limit CPR is still bounded by the Technical Specification limits or determine if new limits need to be defined because of the MELLLA+ addition to the operating map. The main steam isolation valve closure with flux (MSIVF) scram transient analysis, the limiting Reference 2 transient for reactor vessel overpressure protection, was performed at the MELLLA+ operating domain initial power and flow conditions as a comparison against the transient initiated at the increased core flow (ICF) boundary initial conditions. Also evaluated were the loss of feedwater heating (LFWH), the fuel loading error (FLE), and the RWE events.

The pressurization transients (FWCF, LRBPF, TTBPF) were analyzed using the integrated one-dimensional reactor core model that is coupled to the recirculation and control system model ODYN code (Reference 1). The model also simulates pressure dynamics in the steam lines during a transient. The core-wide predictions of key thermal parameters are used in conjunction with a detailed single channel code for evaluating the transient CPR and locating the MCPR. The initial conditions assumed for the MELLLA+ operation are shown in Table 15G-1. The GE14 equilibrium code configuration is used for the transient analysis.

15G.2.2.1 Pressurization Transients

The results of the FWCF, LRBPF, and TTBPF transient analyses are summarized in Tables 15G-2 and 15G-3, including a comparison with the end of Cycle 15 limiting transient results. The transient performance responses are presented on Figures 15G-1 through 15G-6. The effect of the main turbine bypass inoperable and end-of-cycle (EOC) recirculation pump trip (RPT) inoperable are included in the MELLLA+ analysis.

The FWCF, LRBPF, and TTBPF events are identified as limiting abnormal operating occurrences for the NMP2 reload licensing analyses. Experience has shown that pressurization transients are typically more severe from ICF conditions. However, this can be offset by factors such as the time-varying axial power shape that occurs during transients, as well as by the effects of a RPT. At lower core flows, the effectiveness of the RPT and the associated reduction of neutron flux, heat flux, and ΔCPR are reduced. This can cause the lower core flow conditions to become more limiting. Therefore, these events are re-analyzed at MELLLA+ conditions (100P, 85F) to determine the impact of the lower minimum core flow on the ΔCPR and the fuel thermal and mechanical design limits.

As shown in Table 15G-3, the ΔCPR results are higher for all transients when evaluated at ICF conditions when compared to the results of the transients evaluated at MELLLA+ conditions. Additionally, at MELLLA+ conditions, the fuel thermal-mechanical results remain below the design criteria for all transients. Based on these results, operation in the MELLLA+ domain does not negatively impact the fuel thermal margins for the limiting pressurization events.

15G.2.2.2 Loss of Feedwater Heating

The loss of feedwater heating (LFWH) event occurs when a steam extraction line to the feedwater heater is closed or when feedwater is bypassed around one or more feedwater heaters. In either case, the feedwater temperature is reduced and core inlet subcooling is gradually increased. As a result, core power increases due to the negative void reactivity coefficient.

Although experience has shown the LFWH event to be non-limiting for NMP2, this event is most severe when initiated from rated power and minimum licensed core flow. The low core flow condition results in the largest decrease in core inlet temperature for a given feedwater temperature change at a specified power. Therefore, the LFWH event was evaluated in order to assess the impact of the lower minimum core flow on the LFWH ΔCPR and the fuel thermal and mechanical design limit. The LFWH event for NMP2 assumes a feedwater temperature reduction of 100°F.

The PANACEA three-dimensional simulator (Reference 4) is utilized to model this transient event, consistent with the reload licensing methodology.

A ΔCPR of 0.14 was obtained for the LFWH analysis initiated at MELLLA+ conditions (100P, 85F) and the thermal and mechanical overpower results were within the specified design limits.

15G.2.2.3 Fuel Loading Error and Rod Withdrawal Error

The fuel loading error (FLE) and RWE events were considered for operation in the MELLLA+ domain. It was concluded that these events are not impacted by the MELLLA+ expanded operating domain. The FLE consequences are the result of a power mismatch between the correctly and incorrectly loaded fuel (misloaded or misoriented). The power mismatch is the result of localized reactivity and power distributions, and the severity is relatively independent of the core-wide operating conditions. The FLE is also a non-limiting event for NMP2. Therefore, the FLE is not impacted by MELLLA+. Similarly, the RWE consequences are the result of a power increase from the withdrawal of a single control rod. Although bundle powers will change throughout the core, this event is primarily a localized event. The localized power increase is relatively independent of operating conditions. The event is analyzed from rated power and rated flow conditions and the analysis method is designed to bound the variations in core operating conditions. Therefore, the RWE does not require re-analysis for the increased operating domain associated with MELLLA+. However, the RWE event was evaluated to demonstrate fuel duty compliance at 100 percent RTP and 85 percent RCF.

15G.2.3 Conclusion

All operating transients described in Chapter 15 were examined for MELLLA+ operation. The most limiting transients are the LRBPF, FWCF, and TTBPF. Analyses were performed using the nuclear parameters resulting from GE14 equilibrium core characteristics consistent with licensing basis conditions. Off-rated cases of main turbine bypass inoperable and EOC RPT inoperable were also examined.

As summarized in Table 15G-3, the ICF operating limit CPR values remain bounding for MELLLA+ conditions.

15G.3 VESSEL OVERPRESSURE PROTECTION ANALYSIS

Cycle-specific reload analyses are discussed in Appendix A, Section A.5.

The main steam isolation valve closure with flux scram (MSIVF) transient is the design basis event used to demonstrate compliance to the ASME vessel overpressure protection criteria.

The MSIVF event was analyzed at 85 percent core flow with two SRVs out of service, a dome pressure of 1,035 psig, and a reactor power of 102 percent of rated. With the exception of core flow, these are the bounding conditions for vessel overpressure calculations and are consistent with the reload licensing analysis. Although experience has shown peak vessel pressures to be more severe at high core flows, the MSIVF is re-evaluated at MELLLA+ conditions to demonstrate that the ASME Code allowable value for peak vessel pressure is not exceeded.

The ODYN model is utilized to simulate this transient event, consistent with the reload licensing methodology. The transient results at MELLLA+ conditions and the ICF results from the reload licensing analysis are summarized in Table 15G-4. The system responses for the events at MELLLA+ and ICF conditions are shown on Figures 15G-7 and 15G-8.

The peak bottom vessel pressure for the MELLLA+ state point of 102 percent CLTP and 85 percent RCF condition is lower than at the ICF state point of 102 percent CLTP and 105 percent RCF. The peak dome pressure is essentially unchanged. The results, when analyzed at MELLLA+ conditions, are below the ASME overpressure limit of 1,375 psig for the peak vessel pressure and the safety limit of 1,325 psig for the peak dome pressure.

15G.4 STABILITY ANALYSIS

Cycle-specific evaluation is covered in Appendix A, Section A.4.4.4.

Best-estimate TRACG calculations are performed for MELLLA+ to demonstrate that NMP2 EOP actions, including boron injection and water level control strategy, effectively mitigate an ATWS with core instability event.

Long-term TRACG simulations (1500 seconds) are performed for the ATWS Turbine Trip with Bypass (TTWBP) and RPT events with core instability. The RPT event is the most limiting ATWS instability event for MELLLA+.

The hot rod response from the TRACG simulations is used to calculate the PCT. The TRACG hot rod model consists of a single rod with the radial peaking adjusted such that the channel LHGR is conservatively within 5% of the limit of 13.4 kW/ft.

The following features are modeled in the TTWBP event evaluation:

- The TTWBP event is indicated at 0.0 seconds.
- Upon vessel dome pressure reaching the high pressure ATWS RPT setpoint, the feedwater runback is initiated after a delay of 33.0 seconds.
- Following the Turbine trip, the extraction steam to the FW heaters is lost. The FW temperature decreases to 70°F, which is a reasonably low value based on the lowest main condenser temperature historically observed at NMP2. FW temperature is reduced over about a 400-second time period.
- Power oscillations begin at approximately 200 seconds. The oscillations are minor because of the reduced power effect of the feedwater runback.
- SLS is initiated at the time of high pressure ATWS RPT plus a 120-second delay. Boron begins to reduce the reactivity in the core approximately 500 seconds into the event.

The following features are modeled in the NMP2 Recirculation Pump Trip (RPT) event evaluation:

- The RPT event is initiated at 0.0 seconds.
- Operators manually initiate a scram in 20.0 seconds. Scram fails.
- Operators reduce water level to about 446 inches above vessel zero following a 250-second operator delay (270 seconds from RPT initiation).
- Power oscillations begin at various times depending on the initial conditions.
- SLS is initiated at the recognition of 25% power oscillations plus a 120-second operator delay. Boron is assumed to enter the core a little over 360 seconds later. Earlier initiation times modeled in TRACG do not affect the PCT results since water-level reduction occurs sooner and mitigates the event.

For NMP2, the limiting ATWS instability event was initiated from 100% CLTP and 85% rated core flow. The limiting event is the TTWBP for peak vessel pressure and the RPT for the peak cladding temperature. Consistent with the historical ATWS approach, nominal input parameters are generally used for ATWS with instability analyses. The plant-specific TRACG calculations evaluated both the regional mode and core-wide mode oscillation response. The plant-specific boron injection and water level control strategy were modeled to demonstrate that NMP2 EOP actions effectively mitigate the ATWS instability event. A GE14 equilibrium core was used for the calculation.

Reference 19 provides the GEH proprietary evaluation details that support the following conclusion:

- The results of the plant-specific TRACG ATWS instability calculation show the mitigating effect of decreasing water level and boron injection on the core and bundle response to both the TTWBP (for limiting pressure) and RPT (for limiting PCT) ATWS instability events.

- The peak vessel bottom pressure remains below which is below the ASME Service Level C limit of 1500 psig. For calculation of peak level bottom pressure, the plant-specific TRACG ATWS instability calculation assumed two SRVs OOS. The peak suppression pool temperature and the containment pressure limits are not challenged because the turbine bypass remains operational and takes most of the heat load.

- For the NMP2 ATWS instability event, the highest calculated ATWS PCT is significantly less than the 10 CFR 50.46 PCT criterion of 2200°F for the ATWS instability event. The fuel cladding oxidation is insignificant and less than the 17% local cladding oxidation limit.

15G.5 EMERGENCY CORE COOLING SYSTEM PERFORMANCE

Cycle-specific reload analysis is discussed in Appendix A, Section A.6.

For 251-in diameter BWR/5 plants like Unit 2, the effect of low initial core flow on ECCS performance was found to be small. These plants reflood rapidly following a postulated break and have relatively large peak clad temperature (PCT) margins to the 2200°F limit.

The two major parameters that affect the fuel PCT in the design basis LOCA calculation, which are sensitive to the higher load line in the operating power/flow map, are the time of boiling transition (BT) at the high power node of the limiting fuel assembly and the core recovery time. Initiation of the postulated LOCA at lower core flow may result in earlier BT at the high power node, compared to the 100 percent of rated core flow (RCF) results, resulting in a higher calculated PCT. Similarly, initiation of the postulated LOCA at lower core flow affects break flow rate and core reflooding time, compared to the 100 percent of RCF results, which can also result in a higher calculated PCT. The effect on the calculated PCT is acceptable as long as the results remain less than the licensing basis PCT limits.

Calculations assuming the MELLLA+ extended operation domain were performed to quantify the effect on PCT. The MELLLA+ assumptions for the limiting large and small recirculation line break cases resulted in an insignificant change in the calculated PCT. The resulting PCTs which are slightly higher for large recirculation line break, while slightly less for small recirculation line break than the comparable rated assumption cases.

MELLLA+ also has a negligible effect on compliance with the other acceptance criteria of 10CFR50.46. Because cladding oxidation is primarily determined by PCT, MELLLA+ does not affect the amount of cladding oxidation because there is no calculated PCT increase. Compliance with the coolable geometry and long-term cooling acceptance criteria were demonstrated generically for GE BWRs (Reference 11). MELLLA+ does not affect the basis for these generic dispositions. Therefore, MELLLA+ has a negligible effect on compliance with the other acceptance criteria of 10CFR50.46.

In summary, calculations at the CLTP/RCF condition result in the highest PCT for the small break LOCA and set the licensing basis PCT for NMP2.

15G.6 CONTAINMENT SYSTEM RESPONSE

The analyses and evaluations described in this section were performed following the methodology used to evaluate the EPU modification. The results indicate that all peak values are within the design limits.

The containment system response to a LOCA was evaluated for the effect of plant operation in the MELLLA+ region. The initial break flow is directly related to the reactor coolant subcooling. The increased subcooling during MELLLA+ operation can affect the containment thermal-hydraulic response and the containment dynamic loads following a LOCA.

The containment system response can be characterized by the following major parameters:

1. Containment pressure

2. Containment temperature

3. Drywell to wetwell differential pressure

4. LOCA containment hydrodynamic loads

5. Annulus pressurization loads

15G.6.1 Containment Pressure Response

The peak drywell and wetwell pressures occur shortly after the initiation of a large break LOCA. The design basis accident

(DBA) is a recirculation suction line break. Increased vessel subcooling increases the mass rate of break flow into the containment. To evaluate the impact on the containment response, two points on the MELLLA+ power/flow map, i.e., 102P, 85F, and 72.9P, 55F, corresponding to the maximum power and maximum vessel subcooling, respectively, were chosen for comparison with the licensing basis conditions at 102P, 100F, and 102P, 105F. The containment performance analyses at all four points were analyzed with the NRC-approved methodology (Reference 5) using the input conditions summarized in Table 15G-5. The initial containment conditions are identical to those assumed in the current design basis DBA-LOCA short-term containment pressure/temperature response analysis of Reference 12.

The results analysis presented in Table 15G-6 show that all key pressure parameters for MELLLA+ conditions are bounded by those of the base cases.

15G.6.2 Containment Temperature Response

The DBA for peak containment temperature is the main steam line (MSL) break. Under MELLLA+ conditions, the increased vessel subcooling has no effect on the steam line break flow. Therefore, the peak drywell temperature for MELLLA+ is bounded by that for the licensing basis condition.

The peak suppression pool and wetwell airspace temperatures occur at several hours following a LOCA and are governed primarily by the release of decay heat and energy removal by the residual heat removal (RHR) service water. Since the power levels during MELLLA+ operation, which define decay heat, are bounded by that of the licensing basis condition, the peak suppression pool and wetwell airspace temperatures are bounded by their respective values for the licensing basis condition.

The results presented in Table 15G-6 confirm that the short-term containment temperature parameters for MELLLA+ conditions are bounded by those of the base cases for the recirculation suction line break.

15G.6.3 Drywell to Wetwell Differential Pressure

It is observed from the results presented in Table 15G-6 that the peak downward drywell floor differential pressure for MELLLA+ conditions is bounded by the base cases.

15G.6.4 LOCA Containment Hydrodynamic Loads

Three types of hydrodynamic loads are addressed for the DBA-LOCA: 1) pool swell loads, 2) condensation oscillation (CO) loads, and 3) chugging loads. The impact of MELLLA+ on these loads is evaluated by comparing the pressure and temperature responses with those used in the load definitions for the NMP2 Design

Assessment Report (Reference 13). A separate discussion for each follows.

15G.6.4.1 Pool Swell Loads

The pool swell loads include the vent clearing loads, the LOCA bubble wall pressure and submerged structure loads, wetwell airspace pressurization, and the pool swell impact and drag loads. All of these loads are controlled by the initial drywell pressurization (first 2 sec) following the initiation of the DBA-LOCA. The drywell pressure response used in the pool swell design load analysis is presented in Section 6A.4 of Reference 13, and the pressurization exhibited by this pressure response bounds the initial drywell pressurization predicted for MELLLA+. Therefore, it can be concluded that MELLLA+ operation has no adverse impact on the pool swell loads.

15G.6.4.2 Condensation Oscillation

The comparison of the results of the vent steam mass flux versus bulk pool temperature curve obtained from the EPU/MELLLA+ Short-Term analysis cases against the curve for 4TCO Run 2 (Figure 3.9 of Reference 6) demonstrates that the AOR is bounding. CO loads durations are controlled by break size and vessel liquid inventory and are not sensitive to initial reactor power. Therefore, the basis for the NMP2 CO USAR load definition remains applicable and the NMP2 licensing basis CO loads remains bounding for MELLLA+.

15G.6.4.3 Chugging Dynamic Loads

The basis for the NMP2 submerged structure and pool boundary chugging loads is the 4TCO tests (Reference 7). The chugging load definition for NMP2 represents an envelope of all the 4TCO chugging test data. The thermal-hydraulic conditions for these tests (i.e., steam mass flux, air content and SP temperature) were selected to capture the maximum chugging amplitudes possible with a Mark II containment geometry. Therefore, any changes to the NMP2 containment thermal-hydraulic response due to EPU/MELLLA+ would not impact the NMP2 design basis chugging load.

The Mark II chugging duration was defined generically for all Mark II plants in Reference 20. The chugging duration defined in Reference 20 was determined from calculations performed for a bounding Mark II plant (based on the ratio of reactor power-to-vent area). The NMP2 configuration at MELLLA+ remains bounded and the Mark II chugging duration defined in Reference 20 remains valid at MELLLA+. Therefore, the MELLLA+ does not impact the chugging loads evaluation.

15G.6.5 Annulus Pressurization Loads

The annulus pressurization (AP) loads, also known as asymmetric LOCA loads, consist of 1) asymmetric pressurization of the vessel-shield wall annular region, 2) jet thrust (or jet reaction), 3) jet impingement, and 4) pipe whip restraint loads. The forcing function of this family of loads is applied to the vessel supports, vessel internals, piping, pipe-mounted equipment, and floor-mounted equipment. The method of load combination with other dynamic and static loads is described in Table 3.9B-2 and Section 6.2.1.2.4. The effects of AP on components at licensing basis conditions are shown in the Table 3.9B-2 series under the faulted load condition.

The impact of expanding the reactor operating domain to the MELLLA+ power/flow map boundary on high-energy line break (HELB) mass and energy releases to the annulus region was evaluated. The evaluation was performed over the range of power/flow conditions associated with the MELLLA and MELLLA+ boundary.

The Annulus Pressurization (AP) loads were updated for EPU, MELLLA+, and non-conservative assumptions. This effort included AP load calculations at four additional points, D, N, M, and A shown on Figure 15.0-2a. Point N and M relates to MELLLA+ upper boundary, while Points A and D relates to current MELLLA line.

The effect of the increase in AP loads on the total component stresses is reduced when the AP loads are combined with the SSE seismic loads by the square root of the sum of the squares in the faulted load combination. The SSE seismic loads in the load combination are not affected by EPU or MELLLA+. The effect of MELLLA+ on the EPU AP load evaluation has determined that the ARS remains conservative for the rated power MELLLA+, Point N. Minor changes in the AP loads and ARS frequency at off-rated Points A and M are observed, with a few locations showing minor increases. The results of these evaluations show that all reactor vessel and internals, and associated vessel attachments and supports remain within design basis faulted allowable limits.

15G.7 ANTICIPATED TRANSIENT WITHOUT SCRAM

The basis for the current ATWS requirements is 10CFR50.62. This regulation includes requirements for an ATWS-RPT, an alternate rod insertion (ARI) system, and an adequate standby liquid control system (SLS) injection rate. The purpose of the ATWS analysis is to demonstrate that these systems are adequate for operation in the MELLLA+ region. The ATWS analysis, in accordance with the approved licensing methodology (Reference 1) takes credit for ATWS-RPT and SLS, but assumes that ARI fails.

Three ATWS events for NMP2 were re-evaluated: 1) closure of all MSIVs (MSIVC), 2) pressure regulator failure (open) to maximum steam demand flow (PRFO), and 3) loss of offsite power (LOOP). The MSIVC and PRFO events are the most limiting events for the

ATWS acceptance criteria. The LOOP event is limiting in terms of the maximum SLS pump discharge pressure during an ATWS event.

Along with the initial operating conditions and equipment performance characteristics given in Table 15G-7, the following assumptions were used in the analysis:

a. The reactor is operating at 3,988 MWt (100 percent of CLTP).

b. Both beginning-of-cycle (BOC) and EOC nuclear dynamic parameters were used in the calculations.

c. Dynamic void and Doppler reactivity are based on GE14 fuel designs.

d. Two SRV OOS, specified as the valves with the lowest setpoints.

e. The relief mode of the dual-mode SRV is used in the analysis to limit peak vessel pressure.

f. MSIV closure starts at event initiation (time zero) for the MSIVC event.

g. The LOOP event is assumed to be a loss of all auxiliary power transformers at event initiation.

Table 15G-8 presents the results for the MSIVC and PRFO events. The results of the ATWS analysis show that the maximum values of the key performance parameters remain within the applicable limits. Therefore, NMP2 operation in the MELLLA+ region has no adverse effect on the capability of the plant systems to mitigate postulated ATWS events.

The maximum SLS pump discharge pressure depends primarily on the SRV setpoints. The maximum SLS pump discharge pressure during the limiting ATWS event (LOOP) is 1346.3 psig. This value is based on a peak reactor vessel upper plenum pressure of 1226.3 psig that occurs during the limiting ATWS event after SLS initiation. The relief valves used for the SLS at NMP2 have a nominal trip setpoint of 1600 psig and a maximum setpoint drift of -3 percent, resulting in a lower analytical setpoint of 1552 psig. The resultant 205.7 psi margin between the maximum SLS discharge pressure and the relief valve lower analytical setpoint is adequate to accommodate SLS pump pressure pulsation and prevent the SLS relief valve from lifting during system operations, consistent with the guidance contained in NRC Information Notice 2001-13 (Reference 15).

The GNF2 Amendment 22 Compliance to GESTAR II (Reference 21) requires a plant-specific demonstration that the limiting ATWS event response is within the ATWS acceptance criteria. For Unit

2, the calculated ATWS results of record have sufficient margin to the vessel overpressure and suppression pool temperature limit to not require explicit analysis as allowed per Reference 21. Therefore, while it is recognized that the GNF2 NFI will impact the ATWS results, Unit 2 is able to demonstrate compliance to the ATWS acceptance criteria for ATWS events with GNF2 fuel.

15G.8 REACTOR INTERNALS INTEGRITY

The reactor internals are subject to the following loads: reactor internals pressure differences (RIPD), acoustic and flow-induced loads, and structural loads. The reactor internals are also subject to flow-induced vibration (FIV). The impact on these loads of operation in the MELLLA+ region is discussed in the following paragraphs.

15G.8.1 Reactor Internal Pressure Differences

The difference between the 100% CLTP/105% core flow ICF operation point core exit steam flow and the 100% CLTP/85% core flow MELLLA+ operation point core exit steam flow is less than a 0.4% increase. The differences between the vessel steam flow and FW flow rates for the two power-flow points are both less than 0.2% decrease. The dome pressures for the two power-flow points are identical. The small differences between the core exit steam flows, vessel steam flows and FW flow rates will have a negligible effect on the RIPDs for normal, upset, emergency and faulted conditions. Therefore, because the NMP2 core flow at the MELLLA+ statepoint at 85% core flow is less than the current licensed operating domain statepoint at 105% core flow, the normal, upset, emergency and faulted condition RIPDs for MELLLA+ operating domain are less than the values at the NMP2 current licensed operating domain which includes increased core flow up to 105% of rated core flow. Reference 19 provides the GEH proprietary evaluation details that support the conclusion that no further evaluation of these pressure differentials is required for normal, upset, emergency and faulted conditions.

15G.8.2 Acoustic and Flow-Induced Loads

As part of RIPDs, the faulted acoustic and flow induced loads in the RPV annulus on jet pump, core shroud and core shroud support resulting from the recirculation line break LOCA have been considered in the NMP2 evaluation. Reference 19 provides the GEH proprietary evaluation details that support the conclusion that NMP2 RIPDs for faulted conditions continue to be acceptable.

15G.8.3 RPV Internals Structural Integrity Evaluation

Structural integrity evaluations for the MELLLA+ operating domain expansion are performed consistent with the existing design basis of the components. Reference 19 provides the GEH proprietary evaluation details that support the conclusion that no further structural evaluation of the reactor internals is required.

The faulted condition loads for the NMP2 reactor internal components resulting from the MELLLA+ operating domain conditions are bounded. Reference 19 provides the GEH proprietary evaluation details that support the conclusion that no further evaluation for Reactor Internals Structural Evaluation for faulted conditions is required.

15G.8.4 Reactor Internals Vibration

Because the vibration levels generally increase as the square of the flow and MELLLA+ flow rates are lower than CLTP flow rates with power remaining unchanged, CLTP vibration levels bound those at MELLLA+ conditions.

15G.9 STEAM DRYER AND SEPARATOR PERFORMANCE

The ability of the steam dryer and separator to perform their design functions during MELLLA+ operation was evaluated. MELLLA+ decreases the core flow rate, resulting in an increase in separator inlet quality for constant reactor thermal power. These factors, in addition to core radial power distribution, affect the steam separator-dryer performance. Steam separator-dryer performance was evaluated to determine the effect of MELLLA+ on the steam dryer and separator operating conditions, the entrained steam (i.e., carryunder) in the water returning from the separators to the reactor annulus region, the moisture content in the steam leaving the RPV via the main steam lines, and the margin to dryer skirt uncovery.

The steam separator-dryer performance was evaluated at equilibrium cycle limiting conditions of high radial power peaking and 85% core flow. The evaluation indicated that moisture carry-over (MCO) increases at MELLLA+ conditions above the original moisture performance specification of 0.1 wt%.

The impacted components (including steam dryers and separators) were evaluated and found to be acceptable for MCO up to 0.25 wt%. The radiological impact of the increased MCO was found to be acceptable. No changes to the current radiological zones were necessary.

15G.10 HIGH-ENERGY LINE BREAK

The following high-energy line breaks (HELB) were evaluated for the effects of MELLLA+:

a. Main steam line break (MSLB) in the main steam tunnel.

b. Feedwater line break (FWLB) in the main steam tunnel.

c. Reactor core isolation cooling (RCIC) line breaks (various locations).

d. Reactor water cleanup (RWCU) line breaks (various locations).

e. Instrument liquid line breaks (various locations).

The MELLLA+ heat balance review has no significant effect on the steam pressure or enthalpy at the postulated break locations of the main steam and RCIC lines. Similar review of the feedwater piping postulated break locations confirmed no changes to pressure or enthalpy. Therefore, MSLB, FWLB, and RCIC line breaks are not adversely affected by the MELLLA+ region.

The current licensed operating domain includes lower core flows and lower feedwater temperatures than MELLLA+ domain. Therefore, the break flow rates for RWCU and liquid instrument lines are bounded by the current licensed operating domain evaluations.

15G.11 REFERENCES

1. General Electric Company, Licensing Topical Report, "Qualification of the One-Dimensional Core Transient Model (ODYN) for Boiling Water Reactors," NEDO-24154-A, Volumes 1-3, February 1, 1986, NEDC-24154P-A Supplement 1, Volume 4, February 2000.

2. General Electric Company, General Electric Standard Application for Reactor Fuel, "NEDE-24011-P-A-21 and NEDE-24011-P-A-US, May 2015."

3. Not used.

4. Letter, S. A. Richards (USNRC) to G. A. Watford, "Amendment 26 to GE Licensing Topical Report NEDE-24011-P-A, GESTAR II - Implementing Improved GE Steady-State Methods (TAC No. MA6481)," November 10, 1999.

5. General Electric Company, The General Electric Pressure Suppression Containment Analytical Model, Licensing Topical Report, NEDO-10320, April 1971.

6. General Electric Company, Mark II Containment Program, Generic Condensation Oscillation Load Definition Report, NEDE-24288-P, November 1980.

7. General Electric Company, 4T Condensation Oscillation Test Program Final Report, NEDE-24811-P, May 1980.

8. Not used.

9. Not used.

10. Not used.

11. General Electric Company, General Electric Model for LOCA Analysis in Accordance with 10CFR50 Appendix K, NEDO-20566A, September 1986.

12. GE Hitachi Nuclear Energy, Safety Analysis Report for Nine Mile Point Nuclear Power Station Unit 2 Constant Pressure Power Update NEDC-33351P, Revision 0, May 2009.

13. Nine Mile Point Nuclear Station Unit 2, Design Assessment Report, NMP2 USAR Appendix 6A.

14. Not used.

15. NRC Information Notice 2001-13, "Inadequate Standby Liquid Control System Relief Valve Margin."

16. Not used.

17. Not used.

18. Licensing Topical Report, General Electric Boiling Water Reactor Maximum Extended Load Line Limit Analysis Plus, NEDC-33006P-A, Revision 3, June 2009.

19. GE Hitachi Nuclear Energy, Safety Analysis Report for Nine Mile Point Unit 2 Maximum Extended Load Line Limit Analysis Plus, NEDC-33576P, Revision 0, August 2013.

20. Mark II Containment Dynamic Forcing Functions Information Report, NEDO-21061, Revision 4, November 1981.

21. GNF2 Advantage Generic Compliance with NEDE-24011-P-A (GESTAR II), NEDC-33270P, Revision 5, May 2013.

22. Nine Mile Point Nuclear Station, Unit 2 GNF New Fuel Introduction, Task F0902, Anticipated Transient Without Scram, 003N1177, Revision 0, December 2015.

TABLE 15G-1

MELLLA+ TRANSIENT ANALYSIS INPUT AND INITIAL CONDITIONS

	ICF Condition	MELLLA+ Condition
Thermal Power (MWt)	3988(100%)	3,988(100%)
Steam Flow (Mlb/hr)	17.637(100%)	17.633(100%)
Core Flow (Mlb/hr)	113.9(105%)	92.2 (85%)
Feedwater Temperature(°F)	420.5	420.5
Dome Pressure (psig)	1035	1035
Core Coolant Inlet Enthalpy (Btu/lb)	530.0	524.1

TABLE 15G-2

MELLLA+ TRANSIENT ANALYSIS RESULTS
(GE14 Equilibrium Core)

Transient*	Peak Neutron Flux (% Initial)	Peak Steam Dome Pressure (psig)	Peak Vessel Pressure (psig)
LRBPF (Base)	520	1255	1283
LRBPF (MELLLA+)	402	1253	1275
FWCF (Base)	474	1229	1257
FWCF (MELLLA+)	338	1228	1249
TTBPF (Base)	511	1253	1280
ITBPF (MELLLA+)	367	1251	1273

* LRBPF - load rejection with bypass failure
FWCF - feedwater controller failure - maximum demand
TTBPF - turbine trip with bypass failure
(Base) - EOC-11 base case at 100P, 105F
(MELLLA+) - MELLLA case at 100P, 85F

TABLE 15G-3

MELLLA+ TRANSIENT ANALYSIS OPERATING LIMIT ΔCPR VALUES
(GE14 Equilibrium Core)

	ICF Condition (100P, 105F)	MELLLA+ Condition (100P, 85F)
Transient[a]	GE14 [b]	GE14 [b]
LRBPF	0.30	0.26
TTBPF	0.30	0.25
FWCF	0.28	0.23

[a] LRBPF - load rejection with bypass failure
FWCF - feedwater controller failure - maximum demand
TTBPF - turbine trip with bypass failure

[b] GE14 - GE14 Equilibrium Core. GE14 uncorrected ΔCPR values presented

TABLE 15G-4

MELLLA+ VESSEL OVERPRESSURE PROTECTION ANALYSIS,
MSIV CLOSURE (FLUX SCRAM)

Initial Power/Flow (% Rated)	Peak Steam Dome Pressure (psig)	Peak Vessel Pressure (psig)
102/105	1285	1315
102/85	1284	1307

TABLE 15G-5

PLANT CONDITIONS USED IN CONTAINMENT ANALYSIS

	Base Cases		MELLLA Cases	
	(102P, 100F)	(102P, 105F)	(102P, 85F)	(79.2P, 55F)
Reactor Thermal Power (MWt)	4068	4068	4068	3158
Reactor Core Flow (Mlb/hr)	108.5	113.92	92.2	59.7
Feedwater Inlet Temperature (°F)	443.0	443.0	442.8	365.5
Dome Pressure (psia)	1055	1055	1055	1000

TABLE 15G-6

CONTAINMENT PRESSURE AND TEMPERATURE RESPONSE

	Base Cases		MELLLA Cases		Design Limits
	(102P, 100F)	(102P, 105F)	(102P, 85F)	(79.2P, 55F)	
Drywell Pressure (psia)	49.5	49.5	49.4	48.8	59.7
Wetwell Pressure (psia)	43.7	43.7	43.6	43.2	59.7
Differential Pressure (psid)	18.49	18.52	18.32	17.39	25
Drywell Temperature (°F)	280	280	280	279	340
Wetwell Temperature (°F)	116	116	115	113	270

TABLE 15G-7

OPERATING CONDITIONS AND EQUIPMENT PERFORMANCE CHARACTERISTICS FOR ATWS ANALYSES

Parameter	Inputs
Dome Pressure (psia)	1035
MELLLA Core Flow (Mlbm/hr/% rated)	92.2/85.0
Core Thermal Power (MWt/%CLTP)	3988/100.0
Steam/Feed Flow (Mlbm/hr/%NBR	17.636/100
Sodium Pentaborate Solution Concentration in the SLS Storage Tank (% by weight)	13.6
Boron 10 Enrichment (atom %)	92.0
SLS Injection Location	HPCS
Number of SLS Pumps Operating	2
SLS Injection Rate (gpm)	82.4*
SLS Liquid Transport Time (sec)	124**
Initial Suppression Pool Liquid Volume (ft^3)	145,200
Initial Suppression Pool Temperature (°F)	90
Number of RHR Cooling Loops	2
RHR Heat Exchanger Effectiveness (Btu/sec-°F)	265.0
Service Water Temperature (°F)	84
Transient Time at which the RHR Suppression Pool Cooling is Initiated (sec)	1080
High Dome Pressure ATWS-RPT Setpoint (psig)	1095

*Includes dilution flow.

**The injection flow is modeled as a five data point curve in which the first SLS flow is injected 124 seconds after SLS initiation with injection flow increasing to a maximum value of 80 gpm (equivalent to 82.4 gpm total flow)

TABLE 15G-7 (Cont'd.)

Parameter	Current Analysis
SRV Capacity - Per Valve (lbm/hr)/ Reference Pressure (psig)/Accumulation (%)	890,371/1145/3
SRV Configuration	18 DS/RV (2 OOS)

TABLE 15G-8

ANALYSIS SUMMARY - ATWS MSIV CLOSURE AND PRESSURE REGULATOR FAILURE (OPEN) EVENTS
(GE14 Equilibrium Core)

Acceptance Criteria	Criteria Limit	Limiting Results			
		MSIVC BOC	MSIVC EOC	PRFO BOC	PRFO EOC
Peak Vessel Pressure (psig)	1500	1349	1351	1356	1372
Peak Cladding Temperature (°F)	2200	1027	1364	1271	1437
Peak Local Cladding Oxidation (%)	17	<17	<17	<17	<17
Peak Suppression Pool Temperature (°F)	190	160.1	160	159.6	159.8
Peak Containment Pressure (psig)	45	6.5	6.5	6.5	6.5

TABLE 15G-9

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TABLE 15G-10

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TABLE 15G-11

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TABLE 15G-12

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TABLE 15G-12 (Cont'd.)

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APPENDIX 15H

MODE SWITCH MISOPERATION

APPENDIX 15H

MODE SWITCH MISOPERATION

CONCERN (QUESTION F421.27)

Mode switch contact and mode switch operating mechanism malfunctions have caused inadvertent protective actions. Similar malfunctions could have rendered redundant channels of protective functions inoperable. IE Information Notice 83-42 provided notification of potentially significant events concerning mode switch malfunctions. Section 7.2.1 of the Final Safety Analysis Report (FSAR) indicates that the reactor mode switch is used to bypass and enable protective functions, rod withdrawal interlocks and refueling equipment interlocks. Provide a detailed discussion on how the mode switch is incorporated into the overall design, supplemented with detailed drawings and schematics. Please include the following:

(1) Identification of the reactor protection system (RPS), rod block, refueling interlock and other functions important to safety that are dependent on proper mode switch contact operation.

(2) Identification of the analyzed transients and accidents where credit is taken for the operation of any function identified in (1) above.

(3) The surveillance actions necessary to positively verify mode switch contact positions, detect mode switch contact failures and detect mode switch operating mechanism failures for each function identified in (1) above.

RESOLUTION

ASSESSMENT OF EFFECTS OF MODE SWITCH MISOPERATION

NOTE: Each pair of switch contacts is identified by identical digits with the letter C as a suffix on one digit (e.g., 1-1C, 2-2C, etc.). For brevity, only one digit will be used, thus: contact 1, contact 3, etc.

1.1 CONTACTS NORMALLY CLOSED IN RUN POSITION

1.1.1IRM Bypass Contacts - 3, 5, 19, 21, 35, 37, 51, 53
1.1.2
If any of the above contacts are open in the RUN position, the intermediate range monitor (IRM) scram function would be enabled and half-scrams or scrams could result if IRMs were upscale or inoperative.

If any of the above contacts are closed in STARTUP, REFUEL, or SHUTDOWN switch positions, the IRM scram function would be bypassed. This would not be detected immediately but would be evident during weekly channel functional tests because half scrams due to the IRM function could not be induced in the affected channel(s).

1.1.2 Shutdown Scram Interlock Contacts - 9, 25, 41, 57

NOTE: These contacts are also normally closed in STARTUP and REFUEL.

If any of the above contacts are open in the RUN position, a scram or half scram will result.

If any of the above contacts are closed in SHUTDOWN, the shutdown trip function of the affected logic circuit would be disabled.

1.1.3 APRM Interlock Contacts* - 11, 27, 28, 43, 44, 59

If any of the above contacts are open in the RUN position, the average power range monitor (APRM) setdown scram trip function would be enabled and the APRMs would provide half scrams or full scrams at reactor power levels of 15 percent or greater.

If any of the above contacts are closed in any position but RUN, the APRM setdown scram trip function would be disabled and the trips setpoints would be raised to their high setpoint level of about 113 percent of reactor rated power.

1.1.4 Rod Block Interlock Contacts - 30, 62

If either of the above contacts are open in the RUN position, an annunciated rod block signal would be sent to the reactor manual control system (RMCS) to prevent removal of more than one control rod.

If either of the above contacts are closed in STARTUP, REFUEL, or SHUTDOWN, there would be an unannunciated permissive for the RMCS to move more than one control rod. In the STARTUP or REFUEL mode, the permissive would be redundant.

1.1.5 Conclusions

For multiple failures of mode switch contacts which are normally closed in the RUN mode, the principal concerns are:

1. The unannunciated bypass of the IRM scram function in switch positions other than RUN.

* Only contacts 11, 27, 43 and 59 are used for nuclear measurement analysis and control power range neutron monitor (NUMAC PRNM) system (four channels).

2. Failure to cause scram when moving the mode switch to SHUTDOWN.

3. The unannunciated bypass of the APRM setdown scram function in switch positions other than RUN.

4. The unannunciated permissive to move more than one control rod when in the SHUTDOWN mode.

1.2 CONTACTS NORMALLY CLOSED IN STARTUP POSITIONS

1.2.1 MSIV Closure Scram Bypass Contacts - 7, 23, 39, 55

NOTE: These contacts are also normally closed in REFUEL and SHUTDOWN.

If any of the above contacts are open in the STARTUP position, the main steam isolation valve (MSIV) closure scram trip function would be enabled without immediate Operator knowledge, unless one of the two bypass annunciations were to cease. This would require at least two of the four sets of contacts to open.

If any of the above contacts are closed in RUN, an annunciated bypass of the MSIV closure scram trip function would occur.

1.2.2 Shutdown Scram Interlock Contacts - 9, 25, 41, 57

NOTE: These contacts are also normally closed in RUN and REFUEL.

If any of the above contacts are open in the STARTUP position, a scram or half scram will result.

If any of the above contacts are closed in the SHUTDOWN position, the shutdown scram trip function of the affected logic circuit would be disabled.

1.2.3 Steam Line Low-Pressure Isolation Trip Bypass Contacts - 10, 26, 42, 58

NOTE: These contacts are also normally closed in REFUEL and SHUTDOWN.

If any of the above contacts are open in the STARTUP position, the MSIV isolation on low steam line pressure function would be enabled. A MSIV isolation trip or half trip would occur. The isolation trip could be followed by a scram or half scram on MSIV closure.

If any of the above contacts are closed in the RUN position, MSIV isolation on low steam line pressure would be bypassed.

1.2.4 Rod Block Interlock Contacts - 31, 63

If either of the above contacts are open in the STARTUP position, an annunciated rod block signal would be sent to the RMCS to prevent removal of more than one control rod.

If either of the above contacts are closed when not in STARTUP, there would be an unannunciated permissive for the RMCS to move more than one control rod. In the RUN and REFUEL modes the permissive would be redundant.

1.2.5 Conclusions

For multiple failures of mode switch contacts which are normally closed in the STARTUP mode, the principal concerns are:

1. The annunciated bypass of the MSIV closure scram trip function in the RUN mode.

2. The unannunciated bypass of the MSIV isolation on low steam line pressure function in the RUN mode.

3. The failure to initiate scram when the mode switch is moved to the SHUTDOWN position.

4. The unannunciated permissive to move more than one control rod in the SHUTDOWN mode.

1.3 CONTACTS NORMALLY CLOSED IN REFUEL POSITION

1.3.1 MSIV Closure Scram Bypass Contacts - 7, 23, 39, 55

NOTE: These contacts are also normally closed in STARTUP and SHUTDOWN.

If any of the above contacts are open in the REFUEL position, the MSIV closure scram trip function would be enabled without immediate Operator knowledge, unless one of the two bypass annunciators were to cease. This would require at least two of the four sets of contacts to be open.

If any of the above contacts are closed in the RUN position, an annunciated bypass of the MSIV closure scram trip function would occur.

1.3.2 SDV High Water Level Scram Bypass Contacts - 8, 24, 40, 56

NOTE: These contacts are also normally closed in SHUTDOWN.

If any of the above contacts are open in the REFUEL position, the scram discharge volume (SDV) high water level scram trip function would be enabled for the affected logic channel without immediate Operator knowledge, unless one of the two bypass annunciations were to cease. This would require at least two of the four sets of contacts to be open.

If any of the above contacts are closed in RUN or STARTUP, the SDV high water level scram trip bypass would be enabled. (A separate bypass switch for each channel must also be closed to effect the bypass.)

1.3.3 Shutdown Scram Interlock Contacts - 9, 25, 41, 57

NOTE: These contacts are also normally closed in RUN and STARTUP.

If any of the above contacts are open in the REFUEL position, a scram or half scram will result.

If any of the above contacts are closed in the SHUTDOWN position, the shutdown scram trip function of the affected logic channel would be disabled.

1.3.4 Steam Line Low-Pressure Isolation Trip Bypass Contacts - 10, 26, 42, 58

NOTE: These contacts are also normally closed in STARTUP and SHUTDOWN.

If any of the above contacts are open in the REFUEL position, the MSIV isolation-on-low-steam-line-pressure function would be enabled. A MSIV isolation trip or half trip would occur.

If any of the above contacts are closed in the RUN position, MSIV isolation on low steam line pressure would be bypassed.

1.3.5 Rod Block Interlock Contacts - 29, 61

If either of the above contacts are open in the REFUEL position, an annunciated rod block signal would be sent to the RMCS to prevent removal of more than one control rod.

If either of the above contacts are closed when not in the REFUEL mode, there would be an unannunciated permissive for the RMCS to move more than one control rod. In the RUN and STARTUP modes, the permissive would be redundant.

1.3.6 Conclusions

For multiple failures of mode switch contacts which are normally closed in the REFUEL mode, the principal concerns are:

1. The annunciated bypass of the MSIV closure scram trip function in the RUN mode.

2. The unannunciated bypass of the MSIV isolation on low steam line pressure function in the RUN mode.

3. The failure to cause a scram when the mode switch is moved to the SHUTDOWN position.

4. The unannunciated permissive to move more than one control rod in the SHUTDOWN mode.

5. The annunciated bypass of the SDV high water level scram in the RUN or STARTUP mode.

1.4 CONTACTS NORMALLY CLOSED IN SHUTDOWN POSITION

1.4.1 Shutdown Scram Reset Controls - 1, 2, 17, 18, 33, 34, 49, 50

If any of the above contacts are open in the SHUTDOWN position, the shutdown scram/manual scram logic for the affected logic channel will not be configured to permit the logic channel to be reset after a scram trip.

If any of the above contacts are closed in any position except SHUTDOWN, there would be no immediate effect. If both sets of contacts in any logic channel (1 and 2 for logic A1; 17 and 18 for logic B1, etc.) were closed when not in SHUTDOWN, the shutdown scram function would be in the "reset" configuration, and a scram trip would not occur for that logic channel when the mode switch is moved to the SHUTDOWN position.

1.4.2 MSIV Closure Scram Bypass Contacts - 7, 23, 39, 55

NOTE: These contacts are also normally closed in STARTUP and REFUEL.

If any of the above contacts are open in the SHUTDOWN position, the MSIV closure scram trip function would be enabled without immediate Operator knowledge, unless one of the two bypass annunciations would cease. This would require at least two of the four sets of contact to be open.

If any of the above contacts are closed in the RUN position, an annunciated bypass of the MSIV closure scram trip function would occur.

1.4.3 SDV High Water Level Scram Bypass Contacts - 8, 24, 40, 56

NOTE: These contacts are also normally closed in REFUEL.

If any of the above contacts are open in the SHUTDOWN position, the SDV high water level scram trip function would be enabled for the affected logic channel without immediate Operator knowledge, unless one of the two bypass annunciations were to cease. This would require at least two of the four sets of contacts to be open.

If any of the above contacts are closed in RUN or STARTUP, the SDV high water level scram trip bypass would be enabled. (Closure of a separate bypass switch for each channel would be required to complete the bypass.)

1.4.4 Steam Line Low Pressure Isolation Trip Bypass Contacts - 10, 26, 42, 58

NOTE: These contacts are also normally closed in STARTUP and REFUEL.

If any of the above contacts are open in the SHUTDOWN position, the MSIV isolation on low steam line pressure function would be enabled. A MSIV isolation trip or half trip would occur.

If any of the above contacts are closed in RUN, MSIV isolation on low steam line pressure would be bypassed.

1.4.5 Conclusions

For multiple failures of mode switch contacts which are normally closed in the SHUTDOWN mode, the principal concerns are:

1. The annunciated bypass of the MSIV closure scram trip function in the RUN mode.

2. The unannunciated bypass of the MSIV isolation on low steam line pressure function in the RUN mode.

3. The annunciated bypass of the SDV high water level scram in the RUN or STARTUP mode.

1.5 SUMMARY AND CONCLUSIONS

1. All failure modes for the mode switch contacts where contacts open that should be closed would result in scrams or half scrams depending on the number of contacts that are open. At the same time, for conditions of operation where steam line pressure is low, isolation of the main steam lines would occur.

2. In the STARTUP, REFUEL, and SHUTDOWN positions of the mode switch, closures of contacts that should be open (3, 5, 19, 21, 35, 37, 51, 53) would result in a bypass of the IRM scram function in one or more of the RPS channels. Closure of contacts* 11, 27, 28, 43, 44, and 59 would result in raising the setpoint of the normally setdown APRM high flux scram function from 15 percent to 113 percent in one or more of the RPS/neutron monitoring system (NMS) channels.

* Only contacts 11, 27, 43 and 59 are used for the NUMAC PRNM system (four channels).

3. In item 2 above, although the mode switch failure (i.e., contacts closing) would not be immediately apparent to the plant Operator, the failure would be detected during the weekly IRM functional test or daily APRM channel check. If these tests were performed prior to the power increase and after transferring the mode switch to the STARTUP position, then the IRM channel functional tests would detect the IRM failures because no half scram would result. The proposed Technical Specification requirement will be that the IRM channel functional test be performed within 24 hr prior to startup, if it has not been performed in the previous 7 days. Weekly surveillance would be required for the case whereby the "hot standby" (STARTUP position) condition is maintained for long periods of time.

   Also, once a refueling cycle after the mode switch is placed in the STARTUP position, a channel function test of the IRMs high flux trip will be performed.

4. In the RUN position of the mode switch, closures of contacts 7, 23, 39, and 55 would result in the bypass of one or more RPS trip channels related to the MSIV closure scram functions. Closure of contacts 10, 26, 42, and 58 would result in the bypass of one or more nuclear steam supply system (NSSS) trip channels related to the steam line low-pressure isolation function. Concurrent with the incorrect mode switch contact closures, there would be annunciations that one or more of the RPS MSIV closure scram trip channels have been bypassed.

5. Closure of contacts 9, 25, 41, and 57 can bypass the SHUTDOWN mode scram function. If the contacts remain closed during and after transfer of the mode switch to the SHUTDOWN position, such closed contacts would not allow a scram to occur from positioning of the switch. That is, only a half scram or no scram would result. This fact would be immediately apparent to the Operator. Manual scramming of the plant is accomplished by depressing the manual scram switch. The ability to scram the plant from the mode switch is only a secondary effect, and one of several backup alternates to the scram push button.

6. In the SHUTDOWN mode, closure of mode switch contacts 29, 30, 31, 61, 62, and 63 would remove the normal rod

withdrawal block restriction associated with this mode. This fact would be apparent to the Operator because the window for the normal rod withdrawal block annunciator would be extinguished, and its change of state would alert the Operator. The manual positioning of rods is under strict procedural controls. The rod block positioning restrictions are only backups to those controls. Additionally, the Operator would become aware of the situation via standard Technical Specification direction by verifying this rod block by attempting to withdraw a second rod after the first one is withdrawn.

1.6 EVALUATION OF THE EFFECTS OF MODE SWITCH MISOPERATION ON CHAPTER 15 ANALYSES

The potential impacts of the effects of mode switch misoperation on the analyses of transients and accidents presented in Chapter 15 were evaluated. The focus was on certain specific events because of previously expressed NRC concerns with those events or because the events might impact the limiting transients. These specific events were classified into two groups according to the consequences of mode switch misoperation.

1.6.1 Group 1

The events in Group 1 include:

1. The abnormal startup of an idle recirculation loop.
2. The failure of the recirculation flow controller with increasing flow.
3. A rod drop accident.

These are events for which the concern is related to the bypass of the scram function of the IRM while the mode switch is in the STARTUP, REFUEL, or SHUTDOWN positions. This would also raise the scram setpoint of the APRM from the 15 percent "startup" value to the 118 percent "run" value, which corresponds to the analytical limit of 121 percent used for the analyses of Chapter 15 transients and accidents.

None of the Chapter 15 analyses of the events in Group 1 takes credit for either the IRM scram function or the APRM scram function with the setpoint setdown to the 15 to 25 percent level. Events a and b of Group 1 were analyzed from a RUN mode power condition since the Chapter 15 analyses are initiated from about 56 percent power and 40 percent core flow. In the RUN mode, the IRM trips are bypassed and the APRM flux scram setpoint is approximately 118 percent (121 percent analytical limit). The rod drop accident analysis was initiated from 0 percent power, (50 percent rod density); consequently, the mode switch would be in the STARTUP position.

No impact would result from the misoperation of the mode switch in the REFUEL or SHUTDOWN modes.

1. For the analysis of the abnormal recirculation loop startup transient, no credit was taken for the flow reference in the scram for high neutron flux. The high neutron flux setpoint of 121 percent was used. The analysis of this event was initiated from a power level significantly in excess of where recirculation loop startups would normally originate and corresponding to the mode switch in the RUN mode. At lower power levels, the consequences of the event would be less severe; consequently, the impact of the mode switch misoperation on the analysis of this event is of no significant consequence.

   The initiation of an abnormal recirculation loop startup transient when the mode switch is in the STARTUP position would also be of no consequence since operating procedures would require the initial power level to be less than 15 percent. The resulting power increase probably would not cause a scram. If the resulting power level were in excess of Technical Specification requirements related to power, pressure, and core flow, the Operator would take corrective action in accordance with those requirements.

2. The Chapter 15 analyses of the recirculation flow controller failure with increasing flow were initiated from 55 percent power and 35.7 percent core flow conditions, with a 121 percent flux scram terminating the power excursion. Similar events originating from the startup power range of 0 to 15 percent power would be of lesser consequence. Also, at this low power level, normal operating procedures would infer minimum pump speed with individual loop operation. These operating conditions would lessen the effect of a single loop flow increase and would preclude the event of flow control failing with increasing flows on both loops.

3. The analysis in Chapter 15 of the rod drop event only takes credit for the 121 percent APRM trip and takes no credit for the IRM scram function. The event, as analyzed from the 0 percent power level, is terminated by the Doppler effect and is of significance only below about 2 to 3 percent power. At high power levels, the rod drop would be less of a problem because of the influence of the resulting steam voids in the core on the local high reactivity.

1.6.2 Group 2

The events in Group 2 include:

1. The inadvertent closure of the MSIV.

2. The loss of an auxiliary power transformer.

3. The break of a main steam line outside the containment.

4. The failure in the open position of the steam pressure controller.

These are events for which the concern is either the bypass of the main steam line isolation function, due to low steam line pressure by the nuclear steam supply shutoff system (NS^4) in the RUN mode, or the loss of the position scram function of the MSIVs in the RUN mode. Only the isolation function that should result whenever the turbine inlet steam line pressure drops below the (analysis) setpoint level of approximately 720 psig is of concern. No other isolation function of the NS^4 are impacted by the potential mode switch misoperations.

1. The analysis of the MSIV closure event in Chapter 15 does take credit for the scram initiated from limit switches of the MSIV while the mode switch is in the RUN mode. Potential mode switch misoperation could cause this scram function to be bypassed while the mode switch is in the RUN position. However, this bypass would be annunciated in the control room. The operating procedures would require corrective action, since the Technical Specification requirement that all eight channels for the MSIV closure trip function be operable in the RUN mode would be violated. Depending upon the number of inoperable channels, the affected channels and at least one trip system of the RPS would have to be placed in the tripped condition within 1 hr. If both RPS trip systems were affected, the plant would have to be placed in the STARTUP condition within 6 hr.

2. The consequences of the auxiliary power, as analyzed in Chapter 15, are also not affected by any mode switch misoperation. The scram and isolation that occur at about 2 sec (or later) are a direct result of the loss of power to the RPS motor generator (MG) sets and the subsequent disconnection of all power to the loads on the RPS bus.

3. The analysis of the main steam line break outside of the containment does not take credit, either for the low steam line isolation signal that would probably result from low steam line pressure, or for the scram

from MSIV closure. In this analysis, the event is initiated at the level 3 scram to start out with a minimum inventory. At about 0.5 sec into the event, the isolation is assumed to be initiated because of high steam line flow. Although this is not addressed in the analysis, a level 8 high water turbine trip would be expected due to sudden depressurization.

4. Failure of the steam pressure controller in the open position would result in a level 8 high water level turbine trip, which would initiate a scram and a recirculation pump trip (RPT). Further depressurization would be limited to the capacity of the turbine bypass.

   Since an annunciation in the control room would have alerted to the bypass of the isolation function, the Operator would be prepared to actuate MSIV closure manually should this event occur.

Conclusions from these evaluations are that all misoperations of the mode switch are detectable by one or more of the following means:

1. The Operator would be immediately aware of a problem because of the annunciation of bypasses that should not exist for the given position of the mode switch. All mode switch misoperations that might impact the severity of consequences of transients and accidents analyzed in Chapter 15 are in this category. Hence, the probability of a transient occurring before the Operator takes corrective action would be extremely low.

2. The Operator would be immediately aware of a problem in the RPS because of scrams or half scrams, which are also annunciated.

3. The remaining modes of mode switch misoperation would be detected during the weekly channel functional tests of the IRM channel inputs or daily channel check of the APRM channel inputs to the RPS. If these tests were performed prior to the power increase and after the transfer of the mode switch to the STARTUP position, the IRM channel functional tests would detect the failures because no half scram would result.