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NINE MILE POINT
NUCLEAR STATION

March 30, 2010

U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ATTENTION: Document Control Desk

SUBJECT: Nine Mile Point Nuclear Station
Unit No. 2, Docket No. 50-410

License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Technical Specification 3.8.1, AC Sources – Operating

Pursuant to 10 CFR 50.90, Nine Mile Point Nuclear Station, LLC (NMPNS) hereby requests an amendment to the Nine Mile Point Unit 2 (NMP2) Renewed Facility Operating License NPF-69. The proposed amendment would modify Technical Specification (TS) Section 3.8.1, "AC Sources – Operating," to extend the Completion Time for an inoperable Division 1 or Division 2 diesel generator (DG) from 72 hours to 14 days. The proposed amendment represents a risk-informed licensing change, and has been developed using the guidelines established in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

The Enclosure provides a description and technical bases for the proposed amendment, and existing TS pages marked up to show the proposed changes. NMPNS has concluded that the activities associated with the proposed amendment represent no significant hazards consideration under the standards set forth in 10 CFR 50.92. A list of regulatory commitments contained in this submittal is provided in Attachment 1 to the Enclosure.

Approval of the proposed license amendment is requested by March 31, 2011, with implementation within 90 days of receipt of the approved amendment.

A001
NRR

Pursuant to 10 CFR 50.91(b)(1), NMPNS has provided a copy of this license amendment request, with Enclosure, to the appropriate state representative.

Should you have any questions regarding the information in this submittal, please contact T. F. Syrell, Licensing Director, at (315) 349-5219.

Very truly yours,

STATE OF NEW YORK :
: **TO WIT:**
COUNTY OF OSWEGO :

I, Sam Belcher, being duly sworn, state that I am Vice President-Nine Mile Point, and that I am duly authorized to execute and file this license amendment request on behalf of Nine Mile Point Nuclear Station, LLC. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other Nine Mile Point employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Oswego, this 30 day of March, 2010.

WITNESS my Hand and Notarial Seal:

Lisa M. Doran
Notary Public

My Commission Expires:

9/12/2013
Date

Lisa M. Doran
Notary Public in the State of New York
Oswego County Reg. No. 01DO6029220
My Commission Expires 9/12/2013

SB/DEV

Enclosure: Evaluation of the Proposed Change

cc: S. J. Collins, NRC
R. V. Guzman, NRC
Resident Inspector, NRC
A. L. Peterson, NYSERDA

ENCLOSURE

EVALUATION OF THE PROPOSED CHANGE

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1.0 SUMMARY DESCRIPTION

This evaluation supports a request to amend Renewed Facility Operating License NPF-69 for Nine Mile Point Unit 2 (NMP2).

The proposed amendment would revise Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Time (CT) for an inoperable Division 1 or Division 2 diesel generator (DG) from 72 hours to 14 days. This change will provide greater flexibility and more efficient planning of DG inspection and maintenance activities, including required periodic overhauls, during plant operation.

The extended DG CT would typically be used for voluntary planned maintenance and inspections, with a DG overhaul performed at a frequency of no more that once per DG per operating cycle (24 months). However, the extended CT can be entered as necessary to support corrective maintenance.

2.0 DETAILED DESCRIPTION

2.1 Description of the Proposed Change

The proposed amendment includes the following revisions to TS 3.8.1:

- TS 3.8.1 Condition A (One required offsite circuit inoperable) – revise the third Completion Time for Required Action A.3 (Restore required offsite circuit to OPERABLE status):

  From: "6 days from discovery of failure to meet LCO"
  To: "17 days from discovery of failure to meet LCO"

  This change reflects the 11-day extension of the CT for an inoperable DG. This is the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet the Limiting Condition for Operation (LCO).

- TS 3.8.1 Condition B (One required DG inoperable) – revise the Completion Time for Required Action B.4 (Restore required DG to OPERABLE status):

  From: "72 hours <u>AND</u> 6 days from discovery of failure to meet LCO"
  To: "72 hours from discovery of an inoperable Division 3 DG <u>AND</u> 14 days <u>AND</u> 17 days from discovery of failure to meet LCO"

  The primary change is the addition of "14 days" to the Completion Time column to allow extension of the CT from 72 hours to 14 days when either the Division 1 or Division 2 DG is inoperable.

  The first Completion Time ("72 hours") is modified to be applicable only to the Division 3 DG. The Division 3 DG is addressed differently in the TS than the Division 1 and Division 2 DGs due to the dedicated relationship between the Division 3 DG and the High Pressure Core Spray (HPCS) system. If the 72-hour Completion Time is not met for the Division 3 DG, the provision exists for declaring the HPCS system inoperable such that Condition B under TS 3.5.1, "ECCS – Operating," is entered. In accordance with Required Action B.2 of TS 3.5.1, the Completion Time for restoring the HPCS system (i.e., the Division 3 DG) to operable status is 14 days. Thus, between the 72-hour DG CT under TS 3.8.1 and the 14-day HPCS system CT under TS 3.5.1, the overall CT for an inoperable Division 3 DG is 17 days (provided that the inoperable Division 3 DG is the only reason for declaring the HPCS system inoperable and the Reactor Core Isolation Cooling (RCIC) system is operable per Required Action B.1 of TS 3.5.1).

The last (now third) Completion Time is revised from 6 days to 17 days from the discovery of a failure to meet the LCO to reflect the 11-day extension of the CT for an inoperable DG. This is the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet the Limiting Condition for Operation (LCO).

Attachment 2 provides the existing TS pages marked-up to show the proposed changes. Marked-up pages showing associated changes to the TS Bases are provided in Attachment 3 for information only. The TS Bases changes will be processed in accordance with the NMP2 TS Bases Control Program (TS 5.5.10). The TS Bases will reflect the risk-informed nature of the extended DG CT, will note that use of the extended CT for voluntary planned maintenance or inspections should be limited to once within an operating cycle (24 months) for each DG (Division 1 and Division 2), and will list the compensatory measures and configuration risk management controls that must be implemented when entering any extended DG CT.

2.2 Reason for Change

Implementation of the proposed CT extension for an inoperable DG will provide the following benefits:

- Allow additional flexibility in the scheduling and performance of DG preventive maintenance.

- Permit required DG inspections, maintenance, and overhauls to be scheduled and performed online; in particular, the 2-year DG inspections (which typically require 5 days to complete) and the 6-year DG overhauls (which typically require 7 days to complete).

- Allow better control and allocation of resources. Allowing online DG preventive maintenance (including overhauls) provides the flexibility to focus more quality resources on required or elective DG maintenance.

- Potentially reduce the number of individual entries into LCO action statements by providing sufficient time to perform related maintenance tasks with a single entry.

- Avert unnecessary unplanned plant shutdowns to complete emergent DG repairs. Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.

- Improve DG availability during refueling outages. It is anticipated that there will be a reduction in the risk directly attributed to DG maintenance as well as a reduction in the risk associated with the synergistic effects of DG unavailability coincident with the numerous activities and equipment outages that occur during a refueling outage.

Performing DG inspection, maintenance, and overhaul activities while online may include disassembly of the DG. Verification of DG operability after major maintenance or overhaul activities will typically require performance of the monthly start and load tests described in TS Surveillance Requirement (SR) 3.8.1.2 and SR 3.8.1.3. The NMP2 TS currently prohibit the performance of certain TS surveillance testing during Modes 1 and 2 or during Modes 1, 2, and 3 (e.g., the load rejection tests described in SR 3.8.1.7 and SR 3.8.1.8). Thus, planned online elective maintenance will be limited to those activities that do not require the subsequent performance of such surveillance testing, until the TS Mode restrictions are removed (not part of this license amendment request).

2.3 Background

NMP2 TS 3.8.1, "AC Sources - Operating," specifies requirements for the Class 1E electrical power distribution system AC sources. These AC sources consist of the offsite power sources and the onsite standby power sources (i.e., diesel generators). As required by 10 CFR 50, Appendix A, General Design Criterion (GDC) 17, the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to Engineered Safety Feature (ESF) systems. The offsite and onsite power sources are described in Chapter 8 of the NMP2 Updated Safety Analysis Report (USAR). A simplified one-line diagram of the NMP2 onsite 4.16 kV emergency electrical distribution system is shown on Figure 1.

The NMP2 Class 1E AC distribution system supplies electrical power to three divisional load groups, Divisions 1, 2, and 3, with each division powered by an independent Class 1E 4.16 kV emergency bus. The Division 1 and 2 4.16 kV emergency buses each have a separate and independent offsite source of power (the preferred source). The Division 3 (HPCS) 4.16 kV emergency bus can be supplied from either of the two independent offsite sources. Each 4.16 kV emergency bus also has a dedicated onsite DG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition in the event of a design basis accident (DBA).

Offsite power is supplied to the NMP2 switchyard from the transmission network. From the switchyard, three qualified, electrically and physically separated circuits provide AC power to the Division 1, 2, and 3 4.16 kV emergency buses. Offsite power source A (reserve station service transformer A [RSST-A]) provides power to the Division 1 4.16 kV emergency bus and also is the preferred power source for the Division 3 4.16 kV emergency bus. Offsite power source B (RSST-B) provides power to the Division 2 4.16 kV emergency bus, and is also capable of providing power to the Division 3 4.16 kV emergency bus. In addition, either the Division 1 or Division 2 emergency buses can be powered from a third qualified source, the auxiliary boiler transformer (2ABS-X1). The offsite AC electrical power sources are designed and located to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E 4.16 kV emergency bus(es).

The onsite standby power source for each 4.16 kV emergency bus is a dedicated DG. A DG starts automatically upon a loss of coolant accident (LOCA) signal (refer to TS 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation") or upon an emergency bus degraded voltage or undervoltage signal (refer to TS 3.3.8.1, "Loss of Power (LOP) Instrumentation"). After the DG has started, it automatically ties to its respective 4.16 kV emergency bus after offsite power is tripped as a consequence of emergency bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to their emergency buses on a LOCA signal alone. In the event of a loss of offsite power (LOOP), the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a DBA such as a LOCA. The three divisional 4.16 kV emergency buses are electrically independent and physically isolated from each other so that any failure in one division will not jeopardize the safety function of the other divisions. The emergency buses are located in separate rooms in the seismic Category I control building.

The Division 1 and Division 2 DGs are rated for continuous operation at 4400 kW. The individual loads powered by each DG are tabulated in USAR Tables 8.3-1 and 8.3-2, and are summarized in USAR Tables

8.3-5 and 8.3-6, for loading conditions including: (1) simultaneous LOOP and LOCA, and (2) LOOP with unit trip. The Division 3 (HPCS) DG is rated for continuous operation at 2600 kW and has a 2000-hour rating of 2850 kW. It has the capability to restore power quickly to the Division 3 4.16 kV emergency bus in the event of a LOOP and to provide all required power for the startup and operation of the HPCS system. The individual loads powered by the Division 3 DG are tabulated in USAR Table 8.3-3 for loading conditions including: (1) simultaneous LOOP and LOCA, and (2) LOOP with unit trip.

With regard to TS requirements for required AC sources, operability requirements are specified in TS 3.8.1 for both offsite circuits and onsite sources during Modes 1, 2, and 3. The requirements of TS 3.8.1 include the Required Actions to be taken in the event of AC source inoperability, including conditions when one or both offsite circuit(s) is declared inoperable, when one or two DG(s) is declared inoperable, or when an offsite circuit is declared inoperable in combination with a DG declared inoperable. The Required Actions have associated Completion Times for restoring the inoperable source(s) to operable status that are intended to minimize the time the operating plant is exposed to a reduction in the number of available AC power sources, while providing sufficient time to perform testing or effect repairs without unnecessarily requiring a plant shutdown.

The current TS 3.8.1 requires that if a DG is declared inoperable for any reason, the DG must be returned to an operable status within 72 hours or the plant must be placed in at least hot shutdown within 12 hours and in cold shutdown within 36 hours. An exception is allowed for the Division 3 (HPCS) DG by a Note that allows the HPCS system to be declared inoperable in lieu of declaring the Division 3 DG inoperable. This exception allows the Division 3 DG to be inoperable for up to an additional 14 days provided the Reactor Core Isolation Cooling (RCIC) system is operable (see TS 3.5.1). Therefore, the CT extension being requested relates only to the Division 1 and Division 2 DGs.

3.0 TECHNICAL EVALUATION

3.1 Deterministic Evaluation

3.1.1 <u>Defense-in-Depth Evaluation</u>

The impact of the proposed extension of the DG CT was evaluated and determined to be consistent with the defense-in-depth philosophy. The limited unavailability of a single AC power source caused by entry into a TS action does not affect the DG design requirements and does not significantly change the balance among the defense-in-depth principles of prevention of core damage, prevention of containment failure, and consequence mitigation.

The defense-in-depth philosophy requires multiple means or barriers to be in place to accomplish safety functions and prevent the release of radioactive material. NMP2 is designed and operated consistent with the defense-in-depth philosophy. The ESF equipment required to mitigate the consequences of postulated accidents consists of three independent divisional load groups. The station has diverse AC power sources available to these three divisional load groups to cope with the loss of a preferred power source. Furthermore, the loss of an entire divisional load group will not prevent the safe shutdown of the plant in the event of a DBA. Accordingly, the unavailability of a single DG by voluntary entry into a TS action statement for DG maintenance does not reduce the amount of available equipment to a level below that necessary to mitigate a DBA, since the ESF systems of any two of the three divisions are designed with adequate independence, capacity, and capability to provide power to the minimum safety functions necessary to shut down the unit and maintain it in a safe shutdown condition. Therefore, consistent with the defense-in-depth philosophy, the proposed change will continue to provide for multiple means to accomplish safety functions and prevent the release of radioactive material in the event of an accident. In addition, since the proposed extension of the DG CT will allow additional Division 1 and Division 2 DG maintenance to be performed online, there should be an increase in DG availability during refueling outages, thus providing increased defense-in-depth during outages.

The proposed extension of the DG CT does not introduce any new common cause failure modes, and protection against common cause failure modes previously considered is not compromised. Defenses against human errors are maintained, in that the proposed change does not require any new operator response or introduce any new opportunities for human errors not previously considered. Qualified personnel will continue to perform DG maintenance whether such maintenance is performed online or during plant shutdowns.

Appropriate restrictions and compensatory measures will be established to assure that system redundancy, independence, and diversity are maintained commensurate with the risk associated with the extended CT. These include current TS requirements and Maintenance Rule (10 CFR 50.65) programmatic requirements as well as administrative controls in accordance with the configuration risk management program (CRMP).

The Required Actions of TS 3.8.1 for an inoperable DG provide assurance that a LOOP occurring during the period that a DG is inoperable does not result in a complete loss of safety function of critical systems, by:

- Verifying correct breaker alignment and indicated power availability for each required offsite circuit within 1 hour and once every 8 hours thereafter (Required Action B.1),
- Ensuring that redundant required features that are associated with a division redundant to the inoperable DG are not concurrently inoperable (Required Action B.2), and
- Verifying the operability of the remaining DGs by ensuring that a common cause failure does not exist or by increased testing (Required Actions B.3.1 or B.3.2).

In addition to the above TS requirements, appropriate procedures will include provisions for implementing other compensatory measures and configuration risk management controls when a DG is removed from service for any extended CT duration (greater than 72 hours and up to 14 days). These are described in Section 3.2.5 of this license amendment request (LAR).

While in the proposed extended DG CT, additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable risk results will be avoided, in accordance with existing integrated risk management procedure requirements (see Section 3.2.6 of this LAR).

The following plant features also are or will be available to provide additional defense-in-depth in the event that a LOOP occurs while the Division 1 or Division 2 DG is in the extended CT and the other DG (Division 2 or Division 1) becomes unavailable or fails to operate, thereby creating a station blackout (SBO) condition:

1. <u>Division 3 DG as an Alternate Source of AC Power</u>

   If the Shift Manager (SM) determines that Division 1 and Division 2 AC power sources cannot be promptly recovered, the Division 3 (HPCS) DG can be manually cross-connected to either, but not both, the 4.16 kV Division 1 or Division 2 emergency buses to power selected safe shutdown loads. In accordance with the NMP2 licensing and design basis, the Division 3 DG is not assumed to be lost as part of the SBO condition. The electrical equipment that enables the cross-connection alignment is part of the permanent plant design and is illustrated in Figure 1 (a simplified one-line diagram of the NMP2 onsite 4.16 kV emergency electrical distribution system). The existing SBO special operating procedures describe the actions needed to establish the cross-connection and contain the necessary precautions, limitations, and details to minimize the potential for human errors and ensure that this feature will only be used for its intended purpose. This feature is credited in the PRA for the proposed DG CT extension.

The cross-connection is accomplished by stripping one of the de-energized buses (Division 1 or Division 2) of its loads, defeating the HPCS automatic initiation signals, and manually performing breaker line-ups to energize either the Division 1 or Division 2 emergency bus from the Division 3 DG. The HPCS pump will be disabled (placed in pull-to-lock). When the selected 4.16 kV emergency bus is energized, a service water (SW) pump will be started and SW flow will be aligned to the Division 3 DG. The SM will then determine the priority for energizing additional loads based on plant needs, while assuring that the Division 3 DG loading limits are not exceeded. These actions can be readily accomplished by on-shift personnel within two hours of initiation of the SBO condition.

Evaluation of the Division 1 and Division 2 safe shutdown equipment loads following an SBO condition has determined that the Division 3 DG is capable of powering one train of selected safe shutdown loads. As shown in USAR Tables 8.3-1 and 8.3-5, the maximum total Division 1 running load for a LOOP with unit trip is 3083 kW occurring at > 2 hours after event initiation. This total running load includes operation of Residual Heat Removal (RHR) pump A, two SW pumps, and a spent fuel pool cooling (SFC) pump (loaded at T = 2 hours). For Division 2, USAR Tables 8.3-2 and 8.3-6 show a maximum total running load for a LOOP with unit trip of 3009 kW occurring at > 2 hours after event initiation. This total running load includes operation of RHR pump B, two SW pumps, and a spent fuel pool cooling pump (loaded at T = 2 hours).

When operating with the Division 3 DG cross-connected to either the Division 1 or Division 2 emergency bus, only a single SW pump (a 442.5 kW running load) is required to operate to maintain Division 3 DG cooling. In addition, since the current SBO coping analysis credits operation of the RCIC system for reactor coolant system inventory control, the HPCS pump is assumed to be not operating. USAR Table 8.3-3 shows that the remaining Division 3 running load for a LOOP with unit trip is 107 kW. Thus, the net loading on the Division 3 DG when cross-connected to either the Division 1 or Division 2 emergency bus for the SBO condition is:

Description	Division 1 Running Loads (kW)	Division 2 Running Loads (kW)
Maximum Total Load for LOOP with Unit Trip Condition	3083	3009
Minus: One SW Pump	- 442	- 442
Plus: Division 3 Load (not including HPCS pump)	+ 107	+ 107
Net Division 3 DG Load	2748	2674
Margin to Division 3 DG 2000-hour rating of 2850 kW	102	176

The net loading values are less than the Division 3 DG 2000-hour rating of 2850 kW. Thus, it is concluded that the Division 3 DG is capable of supplying all the loads needed for the postulated SBO condition. As noted above, in accordance with the existing SBO special operating procedures, the SM will determine the priority for energizing the safe shutdown loads based on plant needs, while assuring that the Division 3 DG loading limits are not exceeded.

2. Temporary Backup AC Power for Division 1 or Division 2 Battery Chargers

   A 60 kVA, 480/240 VAC, portable generator is available as a temporary backup source of AC power to one of the Division 1 or Division 2 battery chargers. This portable generator can be manually connected to a battery charger using a temporary 480 VAC to 575 VAC transformer and jumper cables. An existing plant procedure contains the necessary precautions, limitations, and details for the use of this portable generator to minimize the potential for human errors and ensure that this feature will only be used for its intended purpose. With the portable generator providing power to a battery charger, the SBO coping ability can be extended well beyond the 4 hours required by 10 CFR 50.63 by assuring that battery power is available to support operation of the RCIC system, main steam safety relief valves, and other features. This feature is credited in the PRA for the proposed DG CT extension.

3. Portable Power Supplies to Maintain RPV Pressure Control Capability

   Four portable power supplies are currently stored onsite. These can be used to facilitate maintaining RPV pressure control for an extended SBO condition in which the main steam safety relief valve (SRV) pneumatic accumulators have exhausted their nitrogen supply. The portable power supplies will enable opening of SRVs by providing a source of power to energize the SRV electro-pneumatic actuator and also to allow re-charging of the accumulators. An existing plant procedure contains the necessary precautions, limitations, and details for the use of these portable power supplies to minimize the potential for human errors and ensure that this feature will only be used for its intended purpose. This feature is credited in the PRA for the proposed DG CT extension.

4. Division 3 DG Backup Cooling Water Supply

   The Division 3 DG will be provided with a source of backup cooling water from the fire protection water supply system and its associated diesel-driven fire water pumps. Since the NMP2 and Nine Mile Point Unit 1 (NMP1) fire protection water supply systems can be cross-tied, either the NMP2 or NMP1 diesel-driven fire pump can perform this function. Unlike the normal Division 3 DG cooling water supplied by either Division 1 or Division 2 of the SW system, operation of the diesel-driven fire pumps is not dependent on the availability of AC power. This modification will allow the HPCS system to function as a source of high-pressure make-up water to the reactor vessel for a loss of SW event or an SBO condition with failure of the RCIC system. Actions needed to establish this backup cooling water supply will be incorporated into plant procedures, including the necessary precautions, limitations, and details to minimize the potential for human errors and ensure that this feature will only be used for its intended purpose. This feature is credited in the PRA for the proposed DG CT extension. The modification and associated implementing procedures will be completed prior to implementation of the DG CT extension.

Note that the four defense-in-depth features described above are not credited in the current SBO coping analysis. The ability of NMP2 to cope with a 4-hour SBO has been evaluated without reliance on these features (see NMP2 USAR Section 8.3.1.5).

3.1.2 Safety Margin Evaluation

3.1.2.1 Design Basis Requirements and Safety Analysis Impact

The proposed extension of the DG CT remains consistent with the codes and standards applicable to the onsite AC sources, except Regulatory Guide 1.93 as discussed in Section 4.1. The DG reliability and availability are monitored and evaluated with respect to Maintenance Rule (10 CFR 50.65) performance criteria to assure DG out of service times do not degrade operational safety over time.

The proposed extension of the DG CT will not affect any safety analyses inputs or assumptions as described in the NMP2 USAR. The unavailability of a single DG due to maintenance does not reduce the number of DGs below the minimum required by the safety analyses. Furthermore, the proposed DG CT extension will have no impact on the availability of the required offsite AC power sources. Thus, the remaining power sources and safety-related equipment will remain capable of providing power to the equipment required to safely shutdown the plant and mitigate the effects of a DBA.

3.1.2.2 SBO Capability Assessment

An SBO is defined as the complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. An SBO would result from a LOOP concurrent with a turbine trip and failure of the onsite emergency AC power system. The SBO Rule (10 CFR 50.63, "Loss of all alternating current power") requires that a nuclear power plant be able to withstand and recover from an SBO of a specified duration. As described in USAR Section 8.3.1.5, NMP2 is classified as a 4-hour coping duration plant with a target DG reliability of 0.975. NRC review and acceptance of the NMP2 response to the SBO Rule are documented in References 1, 2, and 3. The proposed extension of the DG CT will not impact the SBO coping analysis since the Division 1 and Division 2 DGs are not assumed to be available during the coping period. The SBO coping analysis credits operation of the RCIC system in the manual flow control mode to maintain reactor pressure vessel water inventory for core cooling. In addition, the assumptions used in the SBO coping analysis regarding DG reliability are unaffected by the proposed amendment since preventive maintenance and testing will continue to be performed to maintain the DG reliability assumptions. Thus, the proposed extension of the DG CT will not erode the reduction in severe accident risk that was achieved with implementation of the SBO Rule.

3.2 Probabilistic Risk Assessment (PRA)

To further assess the overall impact on plant safety of the proposed extended DG CT, a PRA was performed consistent with the guidance pertaining to risk-informed criteria specified in Regulatory Guide (RG) 1.177, "An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specifications." Note that the term "Completion Time" used in the NMP2 TS is equivalent to the phrase "allowed outage time" used in RG 1.177. The PRA provides a quantitative evaluation of the risk associated with the change in terms of average Core Damage Frequency (CDF) and average Large Early Release Frequency (LERF) produced by the extension of the CT for an inoperable DG. This evaluation included consideration of the Maintenance Rule program established pursuant to 10 CFR 50.65(a)(4) to control the performance of other potentially high risk tasks during a DG outage, as well as consideration of specific compensatory measures to minimize risk. All of these elements were included in a risk evaluation using the three-tiered approach suggested in RG 1.177, as follows:

Tier 1 - PRA Capability and Insights
Tier 2 - Avoidance of Risk-Significant Plant Configurations
Tier 3 - Risk-Informed Configuration Risk Management Program

Evaluations addressing each of these tiers are provided below. The PRA model serves as the primary tool for these evaluations. Therefore, in order to establish the qualification of the PRA model, supplemental background information related to the development, review, application, and quality of the PRA model in place at NMP2 is presented first.

3.2.1 PRA Model Development

The NMP2 PRA is based on a detailed model of the plant that was originally developed from the NMP2 Individual Plant Examination (IPE) and NMP2 Individual Plant Examination for External Events (IPEEE) projects. The original model was reviewed by the NRC and underwent Boiling Water Reactor Owner's Group (BWROG) certification.

The NMP2 PRA has since been upgraded. It is a Level 2, at-power model that includes both internal and external events. A major upgrade of the internal events portion of the model to meet the guidance of RG 1.200, Revision 1, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," as well as the American Society of Mechanical Engineers and American National Standard (ASME/ANS) PRA Standard RA-Sa-2009 was completed in July 2009. A formal, BWROG-sponsored industry peer review of the upgraded internal events model was completed in August 2009. The peer review utilized the process described in Nuclear Energy Institute document NEI 05-04, "Process for Performing Follow-on PRA Peer Reviews Using the ASME PRA Standard," January 2005, and the ASME/ANS PRA Standard. This review confirmed that the PRA model met the requirements of RG 1.200, Revision 1, and ASME/ANS RA-Sa–2009. There were 18 findings identified by the peer review team. Table 1 contains a summary of these findings, including the status of the resolution for each finding and the potential impact of each finding on the proposed DG CT extension. In summary, a majority of the findings were related to documentation and have no material impact on the DG CT extension risk assessment. Resolution of the peer review findings to date has had a minor impact on the model and its quantitative results. Assessment of the remaining open peer review findings has determined that required model changes would result in minor reductions in model quantification results and, therefore, would have a negligible, if any, impact on the conclusions of the DG CT extension risk assessment.

The external events model, which includes fire and seismic events, is based on the IPEEE. The NRC review of the IPEEE is documented in the NRC safety evaluation (SE) dated August 12, 1998 (Reference 4). A summary of the NRC review comments and their disposition is provided in Table 2. The NRC concluded in the SE that the NMP2 IPEEE process is capable of identifying the most likely severe accidents and severe accident vulnerabilities.

The PRA model used to support the proposed DG CT extension (identified as 10U2EPU) reflects the as-designed, as-operated plant at the time that the risk evaluation was performed. In particular, the offsite electric power supply is modeled in sufficient detail to consider out-of-service 115 kV lines or reserve station service transformers. Onsite electrical power distribution is also modeled in detail, including both normal and emergency AC and DC systems. Losses of power at all levels are included as initiating events. Other modeled support systems include those that supply cooling water (service water (SW), reactor building closed loop cooling (RBCLC), and turbine building closed loop cooling (TBCLC)), instrument air, and instrument nitrogen. In addition, this version of the PRA model incorporates updated initiating event frequency data, updated equipment reliability and availability data, and the following two planned plant modifications:

- Extended Power Uprate (EPU) modifications – The model reflects the plant parameters and design modifications associated with EPU. The EPU license amendment request was submitted by NMPNS letter dated May 27, 2009 and is currently under review by the NRC staff. The most significant impact of EPU is that decay heat is increased, which affects the timing associated with operator actions. Equipment performance is expected to largely remain the same or improve based on the changes being implemented to address EPU.

- Division 3 DG Backup Cooling Water Supply – As described in Section 3.1.1 above, the Division 3 DG will be provided with a source of backup cooling water from the fire protection water supply system and its associated diesel-driven fire water pumps. For a loss of SW event or an SBO condition with failure of the RCIC system, this modification will allow the HPCS system to function as a source of high-pressure make-up water to the reactor vessel and will significantly increase the time available to cross-connect the Division 3 DG to either the Division 1 or Division 2 emergency bus. This modification and associated implementing procedures will be completed prior to implementation of the DG CT extension.

The impact of previous risk-informed applications of the PRA model has also been reviewed and incorporated into the model. These previous applications were: (1) the risk-informed inservice inspection (ISI) program, submitted by NMPNS letter dated December 14, 2007 as 10 CFR 50.55a request no. 2ISI-007, and authorized in NRC letter dated December 1, 2008; and (2) extension of the primary containment integrated leak rate test interval from 10 to 15 years, submitted by NMPNS letter dated June 29, 2009 (as supplemented by letter dated August 13, 2009), with NRC review nearing completion. The cumulative risk of the changes resulting from these applications has a negligible impact of the risk assessment for the proposed DG CT extension.

3.2.2 PRA Model Maintenance

The PRA configuration control procedure establishes standard controls and processes for maintaining the PRA model and its associated applications. Ongoing assessments of the PRA model and documentation are part of the normal duties of the PRA staff. When a change to plant design, plant procedures, or operational data is identified that impacts the PRA model, the guidance in the PRA configuration control procedure is used to prioritize the change and assist in the development of an implementation schedule. A graded approach is utilized to ensure that the most significant changes are incorporated as soon as reasonably possible.

The PRA model used to support the proposed DG CT extension incorporates updated initiating event frequency data, updated equipment reliability and availability data, and the planned plant modifications previously noted. In accordance with the PRA configuration control procedure, these PRA revisions have been performed and reviewed by individuals qualified on the specific plant model and by PRA contractors under the direct supervision of the plant PRA staff. These activities meet the ASME PRA Standard, Capability II requirements for quality.

3.2.3 PRA Model Application

The NMP2 Level 2 PRA model was used to determine the risk associated with removing a DG from service for planned maintenance in accordance with the proposed CT extension to 14 days. As noted in Section 3.2.1 above, the PRA model is an integration of the upgraded internal events model and the IPEEE, which explicitly includes fire and seismic events. The risk measures used are CDF and LERF. For the current average maintenance case (not including the proposed DG CT extension), the baseline CDF is 3.6E-06/yr and the baseline LERF is 4.1E-07/yr. Dominant cutsets associated with the baseline CDF and LERF results are shown in Tables 3 and 4, respectively.

The PRA model is used by NMP2 work control and operations personnel throughout the online work planning and implementing processes, as discussed in Section 3.2.6 of the LAR. The results obtained from the PRA model are used along with other inputs, such as TS requirements and operator system knowledge, in a blended approach to determine the final work schedule. The PRA model is currently not applicable to shutdown conditions. The risk assessments for work activities during plant outages are performed consistent with the defense-in-depth philosophy, in accordance with administrative procedures governing shutdown safety.

The guidance contained in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, and RG 1.177 was utilized to assure that the results of the PRA model are acceptable to support the proposed extension of the DG CT, as described below.

3.2.4 Tier 1: PRA Capability and Insights

As noted previously, risk-informed support for the proposed extension of the CT for an inoperable DG is based on PRA calculations performed to quantify the change in plant risk, using the guidance provided in RGs 1.174 and 1.177. The following subsections describe the calculations performed and the risk evaluation results.

3.2.4.1 Methodology

The following risk metrics were used to evaluate the risk impact of extending the DG CT from 72 hours to 14 days:

- ΔCDF_{Avg} = Change in the annual average Core Damage Frequency due to any increased online maintenance unavailability of a DG due to the TS change. This risk metric is used to compare against the criteria in RG 1.174.

- $\Delta LERF_{Avg}$ = Change in the annual average Large Early Release Frequency due to any increased online maintenance unavailability of a DG due to the TS change. This risk metric is used to compare against the criteria in RG 1.174.

- ICCDP = Incremental Conditional Core Damage Probability with a DG out of service for 14 days (the proposed DG CT). This risk metric is used as recommended in RG 1.177 to determine whether the proposed TS change has an acceptable risk.

- ICLERP = Incremental Conditional Large Early Release Probability with a DG out of service for 14 days (the proposed DG CT). This risk metric is used as recommended in RG 1.177 to determine whether the proposed TS change has an acceptable risk.

The ΔCDF_{Avg} due to the proposed extended DG CT is estimated using the following equation:

$$\Delta CDF_{Avg} = (T_1/T) * (CDF_{1Out} - CDF_{Base}) + (T_2/T) * (CDF_{2Out} - CDF_{Base}) \quad (1)$$

Where:

CDF_{1Out} = CDF estimated with the PRA model (zero maintenance configuration) with the Division 1 DG out of service, with compensatory measures and configuration risk management controls implemented.

CDF_{2Out} = CDF estimated with the PRA model (zero maintenance configuration) with the Division 2 DG out of service, with compensatory measures and configuration risk management controls implemented.

CDF_{Base} = Baseline annual average CDF with current (prior to proposed TS change) average unavailability of DGs. This value, from the baseline PRA model, is 3.6E-06/yr.

T = Total fuel cycle time in operating days. The NMP2 fuel cycle is 24 months. In estimating a value for T, it was assumed that the plant was in planned and unplanned outages for a total of 30 days during the 24 month fuel cycle. Thus, T = 2*365 – 30 = 700 days.

T_1 = Total time per fuel cycle (in days) that the Division 1 DG is out of service for the extended CT. The proposed 14-day TS value is conservatively used.

T_2 = Total time per fuel cycle (in days) that the Division 2 DG is out of service for the extended CT. The proposed 14-day TS value is conservatively used.

The $\Delta LERF_{Avg}$ due to the proposed extended DG CT is estimated using the following equation:

$$\Delta LERF_{Avg} = (T_1/T) * (LERF_{1Out} - LERF_{Base}) + (T_2/T) * (LERF_{2Out} - LERF_{Base}) \quad (2)$$

Where:

$LERF_{1Out}$ = LERF estimated with the PRA model (zero maintenance configuration) with the Division 1 DG out of service, with compensatory measures and configuration risk management controls implemented.

$LERF_{2Out}$ = LERF estimated with the PRA model (zero maintenance configuration) with the Division 2 DG out of service, with compensatory measures and configuration risk management controls implemented.

$LERF_{Base}$ = Baseline annual average LERF with current (prior to proposed TS change) average unavailability of DGs. This value, from the baseline PRA model, is 4.1E-07/yr.

ICCDP and ICLERP are calculated using the following equations, which are based on the definitions given in RG 1.177:

$$ICCDP_1 = (CDF_{1Out} - CDF_{Base}) * (14 \text{ days}) / (365 \text{ days/yr}) \quad (3)$$
$$ICCDP_2 = (CDF_{2Out} - CDF_{Base}) * (14 \text{ days}) / (365 \text{ days/yr}) \quad (4)$$
$$ICLERP_1 = (LERF_{1Out} - LERF_{Base}) * (14 \text{ days}) / (365 \text{ days/yr}) \quad (5)$$
$$ICLERP_2 = (LERF_{2Out} - LERF_{Base}) * (14 \text{ days}) / (365 \text{ days/yr}) \quad (6)$$

3.2.4.2 Assumptions

The following are key assumptions in the PRA supporting the proposed extension of the DG CT:

- A 14-day DG outage is assumed to occur once per 24-month fuel cycle for each DG. No distinction is made between preventive/elective and corrective DG maintenance.
- A total of 30 days of planned and unplanned (forced) plant outage time per fuel cycle is assumed.
- AC power recovery is credited as in the baseline PRA, except that the DG that has entered the extended CT for maintenance is assumed to be not recovered.

- Compensatory measures and configuration risk management controls are implemented as described in Section 3.2.5. Compensatory measures not credited in the PRA add margin to the results.

- The modification to provide the Division 3 DG with a source of backup cooling water from the fire protection water supply system and its associated diesel-driven fire water pumps is implemented.

3.2.4.3 Calculations

The following CDF and LERF values for an out of service DG were calculated with the NMP2 PRA using a 1E-13/yr truncation for both CDF and LERF:

CDF_{1Out} = 9.2E-06/yr (Division 1 DG unavailable plus compensatory measures)
CDF_{2Out} = 1.2E-05/yr (Division 2 DG unavailable plus compensatory measures)
$LERF_{1Out}$ = 9.0E-07/yr (Division 1 DG unavailable plus compensatory measures)
$LERF_{2Out}$ = 1.0E-06/yr (Division 2 DG unavailable plus compensatory measures)

These calculations use the zero maintenance configuration and credit compensatory measures as described in Section 3.2.5. Dominant contributors to the CDF and LERF results are shown in Tables 5 and 6, respectively, for the Division 1 DG unavailable, and in Tables 7 and 8, respectively, for the Division 2 DG unavailable. The PRA model for the seismic events appearing in these tables assumes that offsite power must fail due to the earthquake to initiate accident sequences.

3.2.4.4 PRA Results

Substituting the assumed and calculated parameter values into Equations (1) through (6) above results in the risk metric values summarized in the following table:

Risk Metric	Acceptance Guidelines		Evaluation Results
	Source	Guideline Value	
ΔCDF_{Avg}	RG 1.174	< 1.0E-06/yr	2.9E-07/yr
$\Delta LERF_{Avg}$	RG 1.174	< 1.0E-07/yr	2.2E-08/yr
$ICCDP_1$	RG 1.177	< 5.0E-07	2.2E-07
$ICCDP_2$	RG 1.177	< 5.0E-07	3.3E-07
$ICLERP_1$	RG 1.177	< 5.0E-08	1.9E-08
$ICLERP_2$	RG 1.177	< 5.0E-08	2.4E-08

The ICCDP and ICLERP were calculated for both the Division 1 and Division 2 DGs. The results indicate that an outage of the Division 2 DG is more limiting. With the loss of Division 1 or Division 2 power, one train of RHR system containment heat removal equipment is lost. For the loss of Division 2, the inboard containment vent isolation valves also lose power and cannot be opened locally since these valves are not accessible during accident conditions. For the loss of Division 1, the outboard containment vent isolation valves lose power but can still be accessed and opened manually. Thus, prevention of primary containment failure in the event of unavailability of the redundant RHR train is more complicated for the loss of Division 2 than for the loss of Division 1. This asymmetry is the reason why the Division 2 DG has a greater risk importance than the Division 1 DG.

Based on the limiting calculated values for the ICCDP and ICLERP shown above, the proposed extended DG CT has only a small quantitative impact on plant risk. When entering the extended DG CT (greater than 72 hours and up to 14 days), the compensatory measures and configuration risk management controls described in Sections 3.2.5 and 3.2.6 below will apply. Some of the identified measures were not credited in the PRA evaluation; thus, there is inherent conservatism in the PRA results.

3.2.4.5 Uncertainty and Sensitivity Analysis

A review of the following completeness uncertainties considered potentially applicable to the DG CT extension application has determined that these uncertainties have minimal impact on the PRA model results, as summarized below.

- Loss of Offsite Power – An average LOOP initiating event frequency of 3.85E-02/yr has been used in this analysis and is based on NUREG/CR-6890 (Reference 5). Table 3-3 of NUREG/CR-6890 was used to develop a prior distribution, and then a Bayesian update was conducted with plant-specific data. The LOOP frequency is dominated by the August 14, 2003 grid blackout, which is the only at-power LOOP event during the life of the plant. Treatment of this event as a non-recoverable LOOP is considered conservative. Although the offsite power source was degraded, 115 kV offsite power was not completely lost and was recoverable.

- Grid Stability - The stability of existing and projected grid conditions will be confirmed prior to planned entry into the extended DG CT by contacting the transmission system operator (TSO).

- Seasonal variations in LOOP Frequency - There are variations in the seasonal frequency of a LOOP. Summer frequency is the highest and Fall is the lowest. Although average LOOP initiating event frequency has been used in this analysis, planned DG work is not typically scheduled during peak grid demand periods (summer or winter). Sensitivity of the PRA results to variations in LOOP event frequency is addressed below.

- Operation of Equipment after Battery Depletion - The portable generator that is available as a temporary backup source of AC power to one of the Division 1 or Division 2 battery chargers will be pre-staged within the protected area near the NMP2 control building.

- Data Analysis - Failure and availability data has been updated through January 2010.

- Human Reliability Analysis (HRA) – Key HRA modeling elements that impact modeling uncertainty are either minimized or conservatively addressed. Prior to entering the extended DG CT, operating crews will be briefed on the DG work plan. At a minimum, the briefing will include the important procedural actions that could be required in the event a LOOP, SBO, or fire condition occurs.

Several sensitivity analyses have been performed to assess the impact of variations in certain assumptions on the results of the PRA evaluation, as follows:

- Reduced LOOP Frequency – The average LOOP frequency is reduced by 50 percent to reflect a less conservative treatment of the August 14, 2003 grid blackout. During this event, the 115 kV offsite power was not completely lost and was recoverable if both DGs had failed. This results in a risk reduction.

- Seasonal Variations in LOOP Frequency – The average LOOP frequency is increased by a factor of 3 to consider the higher LOOP frequency during the summer. This is conservative relative to information communicated in NRC Information Notice 2006-06, "Loss of Offsite Power and Station Blackout Are More Probable During Summer Period," which notes that the overall LOOP frequency is more than twice as high during the summer period when compared to the annual average. This results in an increase in risk.

- Variation in Extended DG Completion Time Length – The DG out-of-service time is reduced from 14 days to 7 days. The maximum duration of the DG online maintenance is expected to be less than 7 days. In addition, administrative controls require that planned activities be scheduled to be completed within one-half of the TS Limiting Condition for Operation (LCO) completion time limit. This represents a risk reduction.

- Summer LOOP Frequency and Maximum Expected DG Maintenance Duration – Combines the previous two cases, using an average LOOP frequency that is increased by a factor of 3 and a duration of 7 days for the DG maintenance.

- Change in Equipment Out of Service Assumption – For certain systems not protected by compensatory measures (see Section 3.2.5 below), and where redundancy exists, one train of equipment is assumed out of service. Examples include one RBCLC pump, one instrument air compressor, one Division 1 battery charger and one Division 2 battery charger, one feedwater pump, and one SW pump. The risk increase is minimal.

The results of these sensitivity analyses are summarized in the following table:

#	Sensitivity Case Description	Calculated Risk Value	Change from Base Case
1	Reduced LOOP Frequency by 50 percent	ΔCDF_{Avg} = 1.8E-07	– 1.1E-07
		$\Delta LERF_{Avg}$ = 1.5E-08	– 0.7E-08
		$ICCDP_1$ = 1.4E-07	– 0.8E-07
		$ICCDP_2$ = 2.0E-07	– 1.3E-07
		$ICLERP_1$ = 1.4E-08	– 0.5E-08
		$ICLERP_2$ = 1.5E-08	– 0.9E-08
2	Increased LOOP Frequency (Summer) by a Factor of 3	ΔCDF_{Avg} = 7.1E-07	4.2E-07
		$\Delta LERF_{Avg}$ = 5.2E-08	3.0E-08
		$ICCDP_1$ = 5.2E-07*	3.0E-07
		$ICCDP_2$ = 8.5E-07*	5.2E-07
		$ICLERP_1$ = 4.0E-08	2.1E-08
		$ICLERP_2$ = 6.0E-08*	3.6E-08
3	Maximum Expected DG Maintenance Duration of 7 Days (instead of 14 days)	ΔCDF_{Avg} = 1.4E-07	– 1.5E-07
		$\Delta LERF_{Avg}$ = 1.1E-08	– 1.1E-08
		$ICCDP_1$ = 1.1E-07	– 1.1E-07
		$ICCDP_2$ = 1.7E-07	– 1.6E-07
		$ICLERP_1$ = 9.4E-09	– 1.0E-08
		$ICLERP_2$ = 1.2E-08	– 1.2E-08
4	Increased LOOP Frequency (Summer) by a Factor of 3 and 7-Day DG Maintenance Duration	ΔCDF_{Avg} = 3.6E-07	0.7E-07
		$\Delta LERF_{Avg}$ = 2.6E-08	0.4E-08
		$ICCDP_1$ = 2.6E-07	0.4E-07
		$ICCDP_2$ = 4.3E-07	1.0E-07
		$ICLERP_1$ = 2.0E-08	0.1E-08
		$ICLERP_2$ = 3.0E-08	0.6E-08
5	Additional Equipment Out of Service (Other Than Protected Systems)	ΔCDF_{Avg} = 3.5E-07	0.6E-07
		$\Delta LERF_{Avg}$ = 2.3E-08	0.1E-08
		$ICCDP_1$ = 3.1E-07	0.9E-07
		$ICCDP_2$ = 3.6E-07	0.3E-07
		$ICLERP_1$ = 1.9E-08	0
		$ICLERP_2$ = 2.4E-08	0

* Exceeds RG 1.177 guideline value.

As shown by the above sensitivity results, using a summer LOOP frequency (Case 2) results in ICCDP and ICLERP values that exceed the RG 1.177 guideline values of 5.0E-07 for ICCDP and 5.0E-08 for ICLERP. However, by considering the maximum expected duration of the DG maintenance together with the factor of 3 increase in LOOP frequency (Case 4), the calculated ICCDP and ICLERP values would be less than the RG 1.177 guideline values for both the Division 1 DG and the Division 2 DG. In addition, the integrated risk management procedure (see Section 3.2.6) classifies any work that causes unavailability of a diesel generator or offsite line between July 1 and September 1 as high risk. For planned maintenance activities, reasonable schedule changes are evaluated to determine if the high risk level can be prevented. If schedule changes will not prevent the high risk level, then additional risk management actions are taken to reduce the duration of the maintenance activity, minimize the magnitude of the risk increase, and provide increased risk awareness controls.

3.2.4.6 Transition and Shutdown Risk

The proposed extension of the DG CT will reduce the probability of an unplanned manual shutdown when caused by DG unavailability while at power that exceeds the current TS 72-hour CT. The risk associated with an unplanned manual shutdown has been included in the NMP2 PRA as basic event %MSD (manual shutdown with minimal challenges to mitigation systems). The CCDP and CLERP for this basic event are approximately 2E-08 and 8E-11, respectively. These values neglect the condition where a DG requires unplanned corrective maintenance that exceeds the 72-hour CT, requiring plant shutdown.

A shutdown risk model has not been completed for NMP2. DG unavailability and its impact during shutdown depend on the shutdown configuration. Any incremental risk associated with the at-power CT extension would be partially offset by a reduction in overall shutdown risk. Since the reason for the proposed amendment is to perform planned maintenance on one DG during power operation, shutdown risk is not a concern.

3.2.5 Tier 2: Avoidance of Risk-Significant Plant Configurations

As discussed in Section 3.2.6, a CRMP is in place at NMP2 for compliance with the Maintenance Rule (10 CFR 50.65), and in particular, for compliance with paragraph (a)(4) of the rule. The CRMP provides assurance that risk-significant plant equipment configurations are precluded or minimized when equipment is removed from service. Accordingly, any risk increase posed by the removal of a DG from service and the potential combinations of other equipment out of service will be managed in accordance with the CRMP.

The PRA model dominant sequences (cutsets - Tables 3 through 8) and model importance measures were evaluated to assure that important equipment is identified and evaluated when a DG is out of service. The evaluation considered whether compensatory measures and configuration risk management controls should be applied during the extended DG CT to reduce the duration of the maintenance activity, minimize the magnitude of the risk increase, or provide increased risk awareness controls.

The following compensatory measures and configuration risk management controls have been credited in the PRA evaluation and will apply when entering the proposed extended DG CT (greater than 72 hours and up to 14 days):

- The other two DGs are operable and no planned maintenance or testing activities are scheduled on those two DGs.
- No planned maintenance or testing activities are scheduled in Scriba Substation, the NMP2 115 kV switchyard, or on the 115 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability.
- The HPCS system is available and no planned maintenance or testing activities are scheduled.
- The RCIC system is available and no planned maintenance or testing activities are scheduled.
- The NMP2 and NMP1 diesel-driven fire pumps and the cross-tie between the NMP2 and NMP1 fire protection water supply systems are available to provide a backup cooling water supply to the Division 3 DG and no planned maintenance or testing activities are scheduled.

- The Division 1 and Division 2 residual heat removal (RHR) pumps and the low pressure core spray (LPCS) pump are available and no planned maintenance or testing activities are scheduled.

- Both divisions of the redundant reactivity control system and the standby liquid control system (equipment required for mitigation of anticipated transients without scram (ATWS) events) are available and no planned maintenance or testing activities are scheduled.

- The stability of existing and projected grid conditions will be confirmed prior to planned entry into the extended DG CT by contacting the TSO.

- Operating crews will be briefed on the DG work plan. As a minimum, the briefing will include the following important procedural actions that could be required in the event a LOOP, SBO, or fire condition occurs:
  - Alignment of the fire protection water supply system to provide cooling water to the Division 3 DG.
  - Establishing the cross-connection to allow the Division 3 DG to power either Division 1 or Division 2 loads.
  - Utilizing the portable generator as a backup source of AC power to one of the Division 1 or Division 2 battery chargers.
  - Utilizing the portable power supplies to maintain operability of the SRVs.
  - Closing containment isolation valves in the drywell floor drain and equipment drain lines.

The following additional compensatory measures and configuration risk management controls, though not credited in the PRA evaluation, will also apply to the extent possible (considering equipment that may already be out of service) when entering the proposed extended DG CT (greater than 72 hours and up to 14 days):

- The extended DG CT will not be entered for planned maintenance if severe weather conditions with the potential to degrade or limit offsite power availability are present or are predicted to occur.

- Except for the room housing the inoperable DG, no hot work permits will be active for the control building or the normal switchgear rooms.

- Transient combustible loading in the impacted fire zones will be reviewed and any unnecessary transient combustibles will be removed.

- The fire detection and fire suppression equipment in the impacted fire zones is functional or if not functional, equivalent compensatory measures are implemented in accordance with the fire protection program.

- A portable generator is available as a temporary backup source of AC power to one of the Division 1 or Division 2 battery chargers and is pre-staged within the protected area near the NMP2 control building.

The above compensatory measures and configuration risk management controls will be incorporated into appropriate procedures and will also be included in the Bases for TS 3.8.1 (see Attachment 3).

While in the extended DG CT, additional elective equipment maintenance or testing that requires risk-significant equipment to be removed from service will be evaluated in accordance with the CRMP, and activities that yield unacceptable risk results will be avoided. Emergent conditions that result in the protected systems being challenged will be managed to minimize the risk impact.

3.2.6 Tier 3: Risk-Informed Configuration Risk Management Program (CRMP)

Consistent with 10 CFR 50.65(a)(4), NMPNS utilizes a risk-informed CRMP which provides assurance that the risk impact of out of service equipment is properly evaluated prior to performing a work activity. The procedures governing this process are CNG-MN-4.01-1004, "On-Line T-Week Process," and CNG-OP-4.01-1000, "Integrated Risk Management." The guidance provided in these procedures provides assurance that the risk associated with planned online work activities is evaluated and that the work activities are scheduled appropriately. The CRMP includes an integrated review (i.e., both probabilistic and deterministic) to identify risk-significant equipment outage configurations in a timely manner during the online work management process for both planned and emergent work. Appropriate consideration is given to equipment unavailability, operational activities (e.g., testing, load dispatching), and weather conditions. The CRMP includes provisions for performing a configuration-dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of online work activities that remove equipment from service. Risk is re-assessed if an equipment failure or malfunction, or other emergent condition, produces a plant configuration that had not been previously assessed.

For online work activities, a quantitative risk assessment is performed to assure that the activity does not pose an unacceptable risk. This evaluation is performed using the on-line risk monitor software. NMPNS uses EOOS (Equipment Out of Service), an Electric Power Research Institute (EPRI) application that is widely used within the nuclear industry. The EOOS program is able to dynamically calculate the risk associated with planned maintenance and emergent plant conditions. The results of the risk assessment are classified by color code in order of increasing risk of the activity, as shown in the following two tables.

Risk Thresholds Based on the CDF or LERF Levels	
Risk Level	**CDF or LERF**
GREEN	< 2 X PRA Baseline
YELLOW	≥ 2 X PRA Baseline and < 10 X PRA Baseline
ORANGE	≥ 10 X PRA Baseline and < 20 X PRA Baseline
RED	≥ 20 X PRA Baseline

Cumulative Risk Thresholds Based on Incremental Core Damage Probability (ICDP) and Incremental Large Early Release Probability (ILERP) (Assessed for the total work week schedule and single activities exceeding one week in duration)	
Cumulative Risk Level	**ICDP or ILERP**
GREEN	ICDP < 1E-06; ILERP < 1E-07
YELLOW	1E-06 ≥ ICDP < 5E-06; 1E-07 ≥ ILERP < 5E-07
ORANGE	5E-06 ≥ ICDP < 1E-05; 5E-07 ≥ ILERP < 1E-06
RED	ICDP ≥ 1E-05; ILERP ≥ 1E-06

Risk management actions are required for each associated plant risk level, as summarized in the following table:

Risk Level	Risk Management Actions
GREEN	Risk level is acceptable. Apply normal work controls.
YELLOW	Follow the integrated risk management procedure requirements for Medium Risk. Includes actions to reduce the duration of the maintenance activity, minimize the magnitude of the risk increase, and provide increased risk awareness control.
ORANGE	Follow the integrated risk management procedure requirements for High Risk. Includes additional actions to reduce the duration of the maintenance activity, minimize the magnitude of the risk increase, and provide increased risk awareness controls. Requires higher levels of management approvals.
RED	Not allowed for scheduled activities. If entered due to unavoidable emergent condition, then reduce risk as much as possible, follow the integrated risk management procedure requirements and request PRA supporting analyses to assess compensatory actions.

Emergent work is reviewed by work management and operations to evaluate the impact on the risk assessment performed during the schedule development process. Prior to beginning any work, the work scope and schedule are reviewed to assure that nuclear safety and plant operations remain consistent with regulatory requirements, as well as management expectations.

In addition to the CRMP discussed above, certain administrative controls are applied to online maintenance activities. The NMPNS approach to performing maintenance requires a protected division concept. This means that without special considerations, work is only allowed on one division at a time, and access to areas of the plant containing protected equipment is restricted. The administrative controls also require that planned activities be scheduled to be completed within one-half of the TS LCO completion time limit. This requirement applies to both preventative and corrective maintenance. NMP2 also has a Safety Function Determination Program (SFDP) established in accordance with TS LCO 3.0.6 and TS 5.5.11 to ensure that a loss of safety function is detected and appropriate actions taken.

The probability of plant fire events is not assessed for distinct plant activities such as DG maintenance. However, the NMPNS Fire Protection Program significantly minimizes fire risk through various design features and administrative controls that address fire prevention as well as mitigation. NMPNS procedures prescribe the fire prevention and fire protection policies necessary to implement the approved Fire Protection Program required by License Condition 2.F. The program (described in NMP2 USAR Appendix 9A) assures that an adequate balance in the defense-in-depth concepts is maintained to minimize both the probability and consequences of damage due to fire throughout the Nine Mile Point site.

The Fire Protection Program uses a three-tiered approach:

1. The application of administrative controls to prevent fires from starting.
2. The use of active engineered design features to detect, control, and suppress fires that do occur, thereby limiting damage.
3. The use of passive barriers in combination with the design and arrangement of plant safety systems such that fires will not prevent essential plant safety functions from achieving and maintaining safe shutdown of the plant.

Fire prevention is accomplished through existing plant procedures that establish requirements and controls for safe storage of combustible materials and flammable liquids and gases; the use of transient combustibles associated with maintenance and modification activities; performance of hot work activities that use a flame or produce sparks (e.g., welding, flame cutting, brazing, grinding); and activities that impact the normal operation, design, or integrity of fire barrier components (e.g., doors, dampers, penetrations). As with current maintenance practices, these procedures would be used, as applicable, during the extended DG maintenance period to minimize the risk from fire. Section 3.2.5 describes compensatory measures relating to fire protection that will apply when entering the proposed extended DG CT (greater than 72 hours and up to 14 days).

Communication between National Grid (the TSO) and NMPNS is a normal activity that is controlled by existing station procedures. Communication with the TSO is accomplished by either a written work authorization request for routine scheduling of work activities affecting the offsite power system, or a direct-dialing telephone link which is provided for load dispatching purposes. A plant-to-offsite radio communication system, provided by a console located in the NMP2 control room, serves as an alternate means of communicating with the TSO in the event the dial telephone system becomes inoperable. Communications with the TSO are further described in the NMP2 response to NRC Generic Letter 2006-02 (Reference 6).

Planned maintenance activities involving Scriba Substation, the NMP2 switchyard, or associated overhead lines that could impact availability of offsite power to NMP2 are scheduled at least two weeks in advance of the desired start date for the work. These planned maintenance activities are included in the risk assessment performed in accordance with the integrated risk management process. The TSO is contacted prior to performing such work to determine current and anticipated grid conditions. If the NMP2 Shift Manager determines that plant conditions no longer support safely performing the scheduled work, the Shift Manager will immediately notify the TSO and withdraw the NMPNS concurrence for the work.

As indicated in Section 3.2.5 of the LAR, one of the compensatory measures for entry into the extended DG CT (greater than 72 hours and up to 14 days) is that no elective testing or maintenance activities affecting offsite power system availability is occurring during this time period. Implementation of this compensatory measure will require communication with the TSO, thereby effectively notifying the TSO of entry into the extended DG CT.

As described in existing station procedures, the TSO notifies NMP2 of planned or emergent work activities affecting the Scriba Substation or the overhead lines feeding Scriba Substation, and grid conditions that could adversely impact the station. In addition, the control room operators monitor switchyard voltage from the control room. If degraded grid conditions occur during the DG extended CT (i.e., an emergent condition), the effect of this condition on previously performed risk assessments and the associated risk management level would be assessed.

3.3 Maintenance Rule Program Controls

To assure that the proposed extension of the DG CT does not degrade operational safety over time, should equipment not meet its performance criteria, an evaluation is required as part of the Maintenance Rule (10 CFR 50.65). The reliability and unavailability of the three DGs at NMP2 are monitored under the Maintenance Rule Program. If the pre-established reliability or unavailability performance criteria are exceeded for the DGs, consideration must be given to 10 CFR 50.65(a)(1) actions, including increased management oversight and goal setting, to restore DG performance (i.e., reliability and unavailability) to an acceptable level. The performance criteria are risk-informed and are a means to manage the overall risk profile of the plant.

The DGs are all currently in the 10 CFR 50.65(a)(2) Maintenance Rule category (i.e., the DGs are meeting established performance criteria). Performance of DG on-line maintenance during the extended CT is not anticipated to result in exceeding the current established Maintenance Rule criteria for the DGs.

Pursuant to 10 CFR 50.65(a)(3), DG reliability and unavailability are monitored and periodically evaluated relative to the Maintenance Rule performance criteria. The reliability performance criterion is one maintenance rule functional failure (MRFF) per DG in a rolling 24-month period, and the unavailability performance criterion is 1.5% (262 hours) per 24-month period. Current 24-month performance values are as follows:

Performance Parameter	Division 1 DG	Division 2 DG	Division 3 (HPCS) DG
Reliability MRFFs per 20 Demands MRFFs per 50 Demands MRFFs per 100 Demands	 0 0 1	 0 0 0	 0 0 0
Unavailability (per 24-month period)	0.31% (53.7 hours)	0.41% (72 hours)	1.45% (253.2 hours)

During the last 24 months, the Division 1 DG incurred one MRFF due to a cooling water valve relay failure, while the Division 2 and 3 DGs have not incurred any MRFFs in the last 100 demands. Based on current performance and previous outage maintenance window performance, the DGs will remain in (a)(2) status. The data also demonstrates that the current DG reliability exceeds the SBO DG reliability target value of 0.975 stated in USAR Section 8.3.1.5.

The Maintenance Rule program provides a process to identify and correct adverse trends to assure that the proposed extended DG CT does not degrade operational safety over time. Compliance with the Maintenance Rule not only optimizes the reliability and availability of important equipment, it also establishes controls for the management of the risk associated with removing equipment from service for testing or maintenance.

3.4 Conclusions

The proposed extension of the DG CT is based upon both a deterministic evaluation and a risk-informed assessment. The deterministic evaluation concluded that the proposed change is consistent with the defense-in-depth philosophy, in that (1) there continues to be multiple means available to accomplish the required safety functions and prevent the release of radioactive material in the event of an accident and (2) multiple barriers currently exist and additional barriers will be provided to minimize the risk associated with entering the extended DG CT, so that protection of the public health and safety is assured. The deterministic evaluation also concluded that the proposed change will not erode the reduction in severe accident risk that was achieved with implementation of the SBO Rule or affect any of the safety analyses assumptions or inputs as described in the NMP2 USAR. The risk-informed assessment concluded that the increase in plant risk is small and consistent with the guideline values in RG 1.177. When taken together, the results of the deterministic evaluation and risk-informed assessment provide high assurance that the equipment required to safely shutdown the plant and mitigate the effects of a DBA will remain capable of performing their safety functions when a DG is out of service for maintenance or repairs in accordance with the proposed extended CT.

4.0 REGULATORY EVALUATION

4.1 Applicable Regulatory Requirements/Criteria

General Design Criterion (GDC) 17, "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR 50 states, in part, that nuclear power plants shall have onsite and offsite electric power systems to permit the functioning of structures, systems, and components (SSC) important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. GDC-18, "Inspection and testing of electric power systems," states that electric power systems that are important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features to assess the continuity of the systems and the condition of their components. The proposed amendment only extends the TS Completion Time for an inoperable Division 1 or Division 2 DG. This change does not affect conformance with GDC-17 and GDC-18 as described in Section 3.1 and Chapter 8 of the NMP2 USAR.

10 CFR 50.63, "Loss of all alternating current power," requires that light-water-cooled nuclear power plants have the capability to withstand a loss of all AC power (i.e., a station blackout) for an established period of time. This is further addressed by RG 1.155. The proposed 14-day CT for an inoperable DG will not have an impact on the previous SBO coping analysis because the DGs are not assumed to be available during the coping period. In addition, the use of the Division 3 DG as an alternative AC source to power safe shutdown loads associated with the inoperable DG in the event of a LOOP enhances the capability of the electrical distribution system to support safety functions for SBO mitigation. This is further discussed in Section 3.1 of this LAR.

10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that the performance or condition of SSCs be monitored against established goals, in a manner sufficient to provide reasonable assurance that the SSCs are capable of fulfilling their intended functions. It also requires that, before performing maintenance activities, the increase in risk that may result from the proposed maintenance activities shall be assessed and managed. The NMPNS Maintenance Rule program monitors the reliability and unavailability of important plant equipment, including the DGs, and establishes controls for the assessment and management of the risk associated with removing equipment from service for testing and maintenance, in accordance with 10 CFR 50.65. This is further discussed in Sections 3.2 and 3.3 of this LAR.

RG 1.93, "Availability of Electric Power Sources," provides guidance with respect to operating restrictions (i.e., CTs) for an inoperable AC power source. In particular, this guide prescribes a maximum CT of 72 hours for an inoperable onsite or offsite AC source (consistent with the current NMP2 TS). The RG also states that the time limits are explicitly for corrective maintenance activities and do not include preventive maintenance activities which require the incapacitation of any required electric power source. If the proposed changes are approved, NMP2 will continue to conform to RG 1.93 with the exception that the TS CT for an inoperable DG will be increased from 72 hours to 14 days and may be used for DG preventive maintenance activities rather than for corrective maintenance activities only. This deviation is justified based on the technical evaluation provided in Section 3.0 of this LAR.

RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing basis changes by considering engineering issues and applying risk insights. The RG indicates that a risk-informed application should be evaluated to ensure that the proposed changes meet the following key principles:

- The proposed change meets the current regulations, unless it explicitly relates to a requested exemption or rule change.
- The proposed change is consistent with the defense-in-depth philosophy.
- The proposed change maintains sufficient safety margins.
- When proposed changes result in an increase in CDF or risk, the increase(s) should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.
- The impact of the proposed change should be monitored using performance measurement strategies.

These key principles have been considered and are addressed in Section 3.0 of this LAR.

RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," identifies an acceptable risk-informed approach including additional guidance specifically for the assessment of proposed TS CT changes. Specifically, RG 1.177 identifies a three-tiered approach for the evaluation of the risk associated with a proposed TS CT change as identified below.

- Tier 1: PRA Capability and Insights
- Tier 2: Avoidance of Risk-Significant Plant Configurations
- Tier 3: Risk-Informed Configuration Risk Management

This three-tiered approach has been utilized in the risk evaluation for the proposed amendment, as discussed in Section 3.2 of this LAR.

4.2 Precedent

The NRC has approved similar license amendment requests relating to DG CT extensions for a number of plants. The following examples both involve boiling water reactor plants that credited the HPCS DG as an alternate source of AC power that provides defense in depth for LOOP or SBO events occurring when one DG is in the extended outage:

- River Bend Station, Unit 1 (License Amendment No. 125 issued by NRC letter dated September 25, 2002 – TAC No. MB3041)
- Columbia Generating Station (License Amendment No. 197 issued by NRC letter dated April 14, 2006 – TAC No. MC3203)

4.3 Significant Hazards Consideration

Nine Mile Point Nuclear Station, LLC (NMPNS) is requesting an amendment to Renewed Facility Operating License NPF-69 for Nine Mile Point Unit 2 (NMP2). The proposed amendment would modify Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Time (CT) for an inoperable Division 1 or Division 2 diesel generator (DG) from 72 hours to 14 days.

NMPNS has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

1. Does the proposed amendment involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed TS change to increase the CT for an inoperable Division 1 or Division 2 DG from 72 hours to 14 days does not affect the design, function, operational characteristics, or reliability of the DGs. The DGs are designed to mitigate the consequences of previously evaluated accidents and, as such, are not accident initiators.

   Extending the CT for an inoperable DG will not significantly affect the capability of the DGs to perform their accident mitigation safety functions or adversely affect DG or offsite power availability. The consequences of previously evaluated accidents will not be significantly affected since the remaining DGs supporting the redundant Engineered Safety Feature (ESF) systems will continue to be available to perform the accident mitigation functions as designed.

Both a deterministic evaluation and a risk impact assessment were performed to support the proposed DG CT extension. The deterministic evaluation concluded that the defense-in-depth philosophy will be maintained with the proposed DG CT extension. The current TS and 10 CFR 50.65 (Maintenance Rule) programmatic requirements and additional administrative controls provide assurance that a loss of offsite power occurring concurrent with an inoperable DG will not result in a complete loss of function of critical systems. The duration of the proposed DG CT is determined considering that there is a minimal possibility that an accident will occur while a component is removed from service. A risk impact assessment was performed which concluded that the increase in plant risk due to the increased DG CT is small and consistent with the guidance contained in Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

Based on the above discussion, it is concluded that the proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed amendment create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed amendment does not alter the design, configuration, or method of operation of the plant, and does not alter any safety analysis inputs or assumptions. The proposed extended DG CT will not reduce the number of DGs below the minimum required for safe shutdown or accident mitigation. No new component failure modes, system interactions, or accident responses will be created that could result in a new or different kind of accident from any accident previously evaluated.

Therefore, the proposed amendment does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed amendment involve a significant reduction in a margin of safety?

Response: No.

The proposed extension of the DG CT remains consistent with codes and standards applicable to the onsite alternating current (AC) sources, except that the extension deviates from the recommendations of Regulatory Guide 1.93, "Availability of Electric Power Sources." The proposed amendment is justified based on the results of a deterministic evaluation and a risk impact assessment. These demonstrate that the defense-in-depth philosophy will be maintained and the increase in plant risk is small and consistent with the guidance contained in Regulatory Guide 1.177.

The DG reliability and availability are monitored and evaluated with respect to Maintenance Rule performance criteria to assure DG out of service times do not degrade operational safety over time. Furthermore, extension of the DG CT does not affect any safety analysis inputs or assumptions and will not erode the reduction in severe accident risk that was achieved with implementation of the Station Blackout (SBO) rule (10 CFR 50.63). The SBO coping analysis is unaffected by the CT extension since the DGs are not assumed to be available during the coping period. The assumptions used in the coping analysis regarding DG reliability are unaffected since preventive maintenance and testing will continue to be performed to maintain the reliability assumptions.

Based on the above discussion, it is concluded that the proposed amendment does not involve a significant reduction in a margin of safety.

Based on the above, NMPNS concludes that the proposed amendment does not involve a significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

4.4 Conclusions

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

5.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve: (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 REFERENCES

1. Letter from D. S. Brinkman (NRC) to B. R. Sylvia (NMPC) dated May 29, 1991, Station Blackout Rule Safety Evaluation – Nine Mile Point Nuclear Station Unit No. 2 (TAC No. 68571)

2. Letter from J. E. Menning (NRC) to B. R. Sylvia (NMPC) dated November 21, 1991, Station Blackout Rule Supplemental Safety Evaluation Nine Mile Point Nuclear Station Unit No. 2 (TAC No. 68571)

3. Letter from R. A. Laura (NRC) to B. R. Sylvia (NMPC) dated February 7, 1992, Station Blackout Rule Supplemental Safety Evaluation Response Closure – Nine Mile Point Nuclear Station, Unit 2 (TAC No. 68571)

4. Letter from D. S. Hood (NRC) to J. H. Mueller (NMPC) dated August 12, 1998, Review of Individual Plant Examination of External Events, Nine Mile Point Nuclear Station, Unit No. 2 (TAC No. M83646)

5. NUREG/CR-6890, Reevaluation of Station Blackout Risk at Nuclear Power Plants, Analysis of Loss of Offsite Power Events: 1986 – 2004, Volume 1, December 2005

6. Letter from J. M. Heffley (CGG) to Document Control Desk (NRC) dated April 3, 2006, Generic Letter 2006-02, 60-Day Response

Table 1
Summary of Industry Peer Review Findings for the NMP2 Internal Events PRA Model Update

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
1-1	Demands from causes other than surveillance tests were not included in the collection of plant-specific data. (This Finding originated from Supporting Requirement (SR) DA-C6)	DA-C6 DA-C7	SR requires all types of demands be counted or estimated.	Include demands from the four causes listed in the SR. Perhaps use Mitigating System Performance Indicator (MSPI) estimates for MSPI components because that program includes all demands (except post maintenance test).	**Open - Insignificant Impact** This was looked at during the Unit 1 update and considered again during the Unit 2 update. It is slightly conservative and not considered significant to estimate using surveillance procedures. Note that MSPI no longer counts actual events.
1-2	Maintenance Rule unavailability data were used, which include unavailability during plant shutdowns if that component is required to be operable. SR states that only at power unavailability should be used. NUREG/CR-6890 Vol. 2, Table A-2, data indicate that DG unavailability during shutdown is 5 to 10 times higher than during power operation. (This Finding originated from SR DA-C-13)	DA-C13	SR specifically says to include UA events only occurring while the plant is at power.	Either exclude Maintenance Rule unavailability data while the plant is shut down, or provide more justification why using such data does not significantly affect the results if only at power unavailability were to be used.	**Closed - Minor Impact (Reduction)** Section 3 of the Data Analysis (DA) Notebook and the model were updated with a maintenance unavailability calculation that does not include unavailability during non-power operation.

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
1-9	The selection of a failure probability of 1.0E-4 for the low-pressure system component(s) rupturing given exposure to RCS pressure and temperature is optimistic given the information provided in the referenced NUREG/CR-5603. (This Finding originated from SR LE-D4)	LE-D4	More realistic failure probabilities of 0.1 or 0.01 would increase the frequencies of these ISLOCA sequences by a factor of 100 to 1000.	Reconsider the 1.0E-4 failure probability or provide detailed justification for such a low probability.	**Closed - Minor Impact (Increase)** Section 5 of the DA Notebook was revised to provide a more detailed evaluation of the NMP2 piping and heat exchanger fragilities. As a result, the probability of rupture was revised in the model, which varies for each system from 0.05 to 0.003.
1-11	Several spray events identified (for example, FDSWCB1 and FDSWCB2 in Table 5.1 of the Internal Flooding (IF) Notebook) use flood frequencies rather than spray frequencies from EPRI Report 1013141. There could be others. (This Finding originated from SR IFEV-A5)	IFEV-A5	Incorrect frequencies (too low) were used for these internal flood initiators.	Use the spray frequencies for these initiating events. Check other internal flooding initiators for correct type and frequency.	**Closed - Minor Impact (Increase)** Reviewed the IF Notebook Main Report and Appendix B for potential spray events and frequency. The following changes were required: (1) Initiators FDSWCB1, FDSWCB2 and FDSWCB5 were changed to spray frequency initiating events because there is no detection and no propagation from these rooms. (2) North Auxiliary Bay panel impact corrected in Appendix B (no PRA impact). (3) Sections 4.3, 4.5, 4.6 and 5.4 of the IF Notebook were updated to include the screened spray events where PRA equipment was affected.

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
2-5	P. 2-7 of the DA Notebook states that a Bayesian analysis was not done when there are no plant-specific failures. This is unacceptable for Category II or Category III. The discussion justifying not performing such updates on p. 2-6 and 2-7 of the DA Notebook is misleading because of the very small failure probabilities involved in the example given. Based on NUREG/CR-6928 parameters for distributions with as few as 200 to 1000 demands, the posterior mean could drop by a factor of 2. (This Finding originated from SR DA-D1)	DA-D1	It is not acceptable to skip performing a Bayesian update when zero plant-specific failures are observed.	Perform Bayesian update when data is available and zero plant-specific failures are observed, or, alternatively, show that it is unlikely to get the required number of demands to significantly change the failure probability for specific equipment showing zero failures.	**Closed - Minor Impact (Decrease)** Section 2 of the DA Notebook and model were updated with Bayesian analysis for zero events down to failure rates on the order of 1E-3. The conservatism of not performing this update for lower failure rates is shown to be minor.

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
2-6	A critical test of the posterior that is suggested in this Supporting Requirement is: (c) examination of inconsistencies between the prior distribution and the plant-specific evidence to confirm that they are appropriate. There is at least one case in which data is inconsistent—Motor Operated Valve (MOV) (lake) fails to open. There were 6 failures in 150 demands. The prior from NUREG/CR-6928 for MOV FTO/C has a mean of 1.07 E-3. The method from NUREG/CR-6823, Sections 6.2.3.5 & 6.3.3.4, describe a method for consistency evaluation that suggests that greater than or equal to 2 failures would be inconsistent and that another prior should be used. There is no documentation of any NMP2 analysis like this. (This Finding originated from SR DA-D4)	DA-D4	Consistency between the plant-specific data and the prior was not evaluated. A representative example of such an inconsistency is provided.	Perform recommended consistency analyses for all data.	**Closed - Minor Impact (Increase)** Section 2.7 of DA Notebook updated to include test of key distributions with documentation of methodology. A few distributions were identified as potentially inconsistent (prior versus posterior and plant data). As a result, the uncertainty in the prior distribution was increased to be more representative of plant data.

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
2-9	Section 2.12 of the Service Water System (SWS) Notebook, which deals with Component Spatial Information, needs a small improvement. It is stated that SWS is credited for operation after containment failure, but no justification is given for why it would be available, given spatial effects from containment failure. (This Finding originated from SR SY-B8)	SY-B8	This is an isolated example of weakness in the treatment of spatial effects. They are treated well in other notebooks. However, treatment of spatial effects is a clear requirement of the Standard.	Provide discussion of effects on SWS of containment failure.	**Closed - Documentation Only** Section 2.12 of SY.04 was corrected to address the fact that SWS is not affected by containment failure.
2-11	The list of sources of uncertainty has been omitted from Section 3.5 of the 125 Vdc SY Notebook. (This Finding originated from SR SY-C3)	SY-C3	This is an isolated occurrence of failing to provide this information; however, requirements of the ASME Standard to list sources of uncertainty are clear.	Discuss sources of uncertainty in the 125 Vdc SY Notebook.	**Closed - Documentation Only** A potential important uncertainty is associated with battery life, which was added to the Notebook.
2-16	This SR requires identification of contributors to CDF. To satisfy Category II (and III) requires including structures, systems, and components (SSCs) and operator actions that contribute to Initiating Event (IE) frequencies. These are not included for NMP2, so only Category I has been met. (This Finding originated from SR QU-D6)	QU-D6	Since Category II requires including SSCs and operator actions that contribute to IE frequencies, this is a finding.	Identify CDF contribution from SSCs and operator actions that contribute to IE frequencies.	**Closed - Documentation Only** Support system initiating event fault trees have been added to the model. The IE Notebook refers to this. SY.00 Notebook provides methodology. Applicable SY notebooks develop the models. ------------------------ **Open - Documentation Only** Equipment and operator contributions will be developed in the Quantification (QU) Notebook. The IE Notebook will be updated with correction factors.

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
3-5	At the time of the Peer Review, various PRA documentation notebooks were not signed by performers, reviewers, or approvers. (This Finding originated from SR MU-F1)	MU-F1	The lack of signatures was widespread throughout the PRA notebooks. The preparer, reviewer, and approver signatures normally imply that they have concurred with the statements made in the associated documentation.	Obtain signatures from the personnel who were designated preparer, reviewer, or approver. Add lines for signature dates. Ensure documentation (PRA notebooks) reflects proper revision number.	**Closed - Documentation Only** The Peer Review issuance of all notebooks has been signed and issued.
3-6	The IF Notebook describes a plant feature important in mitigation of flooding that could disable Div 1 and Div 2 switchgear – "There is an open door that is held open by a latch, which actuates to close door on a fire alarm." (pg 4.1-6). This is cited throughout the IF notebook in multiple places. This design change has not actually been installed, but an interim measure to block the door open has been taken. (This Finding originated from SRIFSO-B1)	IFSO-B1	This feature has a significant impact on IF results. The IF Notebook and model should accurately reflect current plant configuration.	Revise documentation (and flooding model, if required) to accurately reflect current plant configuration.	**Closed - Documentation Only** The IF Notebook was revised to indicate that doors are currently held open by door stop and there is a future modification which will hold doors open by latch. This was a documentation issue only.

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
3-8	An important plant modification associated with an internal flood event that could disable Div I and II Switchgear is not entered into the CRMP database.	MU-A1	This modification has a significant impact on core damage frequency, and tracking of the modification is required by this SR and CNG-CM-1.01-3003, "Probabilistic Risk Assessment Configuration Control."	Enter and track this issue in the CRMP database.	**Closed - Documentation Only** CRMP 376 issued. No impact on model or results.
4-7	Several system notebooks do not have a completed system walkdown. (This Finding originated from SR SY-A4)	SY-A4	There are only 3 systems.	Provide completed system walkdown checklist for those systems in Appendix C.	**Closed - Documentation Only** Only 3 System Notebooks (Automatic Depressurization System, Vapor Suppression and Reactor Recirc) did not have documented walkdowns (NA was included) and it is stated that they are in the Drywell (inaccessible).

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
5-2	Routine system alignments contributing to initiating event frequencies are not included. (This Finding originated from SR IE-A6)	IE-A6	Does not meet IE-A6 Category II requirements.	Include routine system alignments in the calculation of initiating event frequencies, where applicable.	**Closed - Documentation Only** Routine alignments are already included in the average initiating event frequency development. In addition, the addition of support system initiating event fault trees to the model (see Finding 2-16) adds some important alignments for these systems. ----------------------- **Open - Insignificant** It would be a significant effort to add the type of factors that are typically reserved for EOOS risk management modeling such as ½ scram testing, etc. This will have to wait until a plant reliability program is developed (e.g., scram, turbine trip risk).
6-1	In some cases the assignment of a conservative screening human error probability (HEP) value may not have been appropriate given the risk significance of the operator action it represents. In particular, the use of a conservative screening value of 1E-02 assigned to the HEP ZHS05_HSROOMCOL, "Operator Fails to open HPCS ROOM Doors and HVAC Duct," may not have been appropriate given the risk significance of the HPCS room cooling support system. (This Finding originated from SR HR-G1)	HR-G1	Failure to perform a detailed analysis for the estimation of HEPs that represent significant human failure events (HFEs).	Identify risk-significant HFEs in the PRA model, and perform detailed analysis using appropriate human reliability analysis (HRA) methodology(ies).	**Closed - Documentation Only** Section 1 of HRA Notebook updated to explicitly identify HEPs based on screening, the basis for screening, and their importance. ----------------------- **Open - Insignificant** Detailed HRA will be considered in future updates as appropriate.

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
6-4	The most significant operator action in terms of importance (RRW = 2, RAW = 11) is ZZOHX, "Failure to Recover Heat Removal before Containment Failure." There does not appear to be a detailed analysis of this operator action with regard to procedure availability and operator training (nor is justification given for omission), nor were shaping factors and sufficiency of manpower for performing this recovery action included in the evaluation which documents this recovery action. (This Finding originated from SR HR-H2)	HR-H2	Failure to satisfy HR-H2 criteria for Capability Category I/II/III for significant operator action.	Perform a review of all significant operator recovery actions, and ensure that a detailed analysis is presented which includes consideration of procedure availability and operator training (or justification given for omission), as well as consideration of the shaping factors and sufficiency of manpower for performing the recovery actions.	**Closed - Documentation Only** ZZOHX is not an operator action. The modeling of recovery term ZZOHX includes an operator action ZOH01, which is a direct dependency for operators performing containment heat removal. ZZOHX is an equipment recovery value for failure to recover loss of containment heat removal, given ZOH01 was previously successful. Agree that the basis for ZZOHX in Section 5 of the DA Notebook needs improvement and this has been updated. Also, sufficiency of manpower for actions required after one day is not considered an issue.
6-5	The Accident Sequence (AS) Notebook does not contain the event tree top event fault trees, which are necessary for understanding the accident sequence logic. (This Finding originated from SR AS-C1)	AS-C1	The AS analysis documentation does not provide sufficient information to facilitate PRA applications, upgrades, and peer review.	Revise the AS Notebook to include all applicable top-logic fault trees, and additional description in the notebook to explain the top event logic.	**Closed - Documentation Only** The final post Peer Review issuance of the AS Notebook has all the documentation in the AS Notebook as suggested versus external (facilitates review etc).

Table 1 (Continued)

Finding	Finding Description	Assoc. SR	Basis for Significance	Peer Review Team Suggested Resolution	NMP2 DG CT Extension Impact
6-10	Based on a review of the design features, detection and response section, this supporting requirement appears to have been met for the above areas except for the South Aux Service Bldg. (This Finding originated from SR IFSN-A14)	IFSN-A14	Table 4-14 indicates that the South Aux Service Bldg can be screened based upon the presence of flood detection. The NMP2 IF Notebook, Section 4.2.6, does not indicate that there is detection for this area. The responsible Constellation engineer corroborated this conclusion.	Revise Table 4-14 to change YES to NO under the column for Criteria #3 for the South Aux Service Bldg.	**Closed - Documentation Only** Footnote (1) was added to the "Yes" which states "There is no detection in the South Aux Service Building. However, there is no PRA equipment here, the piping is relatively small and there is reliable detection, isolation and significant time available when propagation occurs to Turbine and or Control buildings."

Table 2
Summary of NRC Review Comments on the NMP2 IPEEE

The NRC Safety Evaluation (SE) for the NMP2 IPEEE (Reference 4) was reviewed and specific comments were identified and assigned as individual items for the NMP2 PRA update performed in 1998. Provided in this table is a listing of each comment, along with the Nine Mile Point (NMP) PRA team response/disposition.

Item(1)	Comment	Response/Disposition
IPEEE-SE Page 2	0.5g HCLPF for 24 hrs does not meet Electric Power Research Institute (EPRI) seismic margin assessment (SMA) guidance.	Clarification: The 0.5g HCLPF is for 72 hours (see comments on TER below).
IPEEE-SE Page 6	Vulnerability definition not provided.	The American Nuclear Society (ANS) provides the following definition for vulnerability: *"the conditional probability of an SSC failure as a function of the intensity of the external event hazard."* Reference: *EPRI Technical Report 1000896: Planning For Risk-Informed Seismic Regulations.*
IPEEE-SE Page 6	Plant improvements needed.	<u>Seismic mounting of rack, cabinet and hoist assembly</u> The plant modifications for the seismic mounting described have been made (IPEEE page 7-2). <u>CR Fire</u> Procedure EOP-RPV is now retained at the remote shutdown panels. The control room fire risk in the PRA is judged to be conservative and is not dominating. There are no plans to add explicit TSC guidance or additional training.
IPEEE-TER Page vii	No freeze date.	This comment refers to a data freeze date beyond which additional data would not be considered. A date for data analysis for this PRA was implemented; however, other aspects of the PRA were allowed to change as appropriate to final sign-off.
IPEEE-TER Page ix Page 30	Tornado screening incomplete.	No action to be taken. NRC's analysis also shows that risk from high winds is low and can be screened.
IPEEE-TER Page ix, xii Pages 31-34, 44	External flood bounding analyses appear flawed and incomplete.	It is very difficult to estimate the risk from floods and there are numerous combinations of events that must be considered. It is NMP's position that a detailed analysis, considering plant procedures and timing, would lead to a low risk on the order of 1E-6/yr. Since there is very little that can be done cost effectively to reduce this risk further, no additional analyses are planned.

Table 2 (Continued)

Item[1]	Comment	Response/Disposition
IPEEE-TER Pages x, xii Pages 7, 9, 10, 11, 41, 43	0.5g HCLPF for 24 hrs and not meeting EPRI SMA guideline for success reliability.	Clarification: The 0.5g HCLPF is for 72 hours. Only when using success path reliability guidelines of EPRI SMA does a 0.23 HCLPF result unless we credit equipment not in analysis scope. EPRI SMA is only guidance and justification for deviating is provided by the PRA analysis. This was shown to be non-risk significant by NMP and TER seems to agree. Also, note that the NMP PRA success criteria are for 24 hours not 72 hours, including external events.
IPEEE-TER Page x, xii Page 2, 24, 28, 44	Additional equipment failures due to smoke and combustibles not adequately addressed.	NMP does not know of any analyses to address this issue. If new analyses become available NMP will consider this further.
IPEEE-TER Page x Pages 24, 28, 44	No fire barrier failure rates in analysis; cross zone fire analysis.	Because of limited combustibles, limited active barriers, reliable detection and suppression, the screening and analysis is judged conservative. Scenarios where fire barriers failed were judged to be very low risk contributors. NMP agrees that documentation of these judgments could be improved.
IPEEE-TER Page x Page 31	GI-103: No details of re-evaluation in submittal.	The USAR re-evaluation was not repeated in submittal and there is no plan to do this – judged to be of limited value.
IPEEE-TER Page xi Page 45	Plant improvements identified during walk down.	The storage rack near the RCIC motor-operated valves has been secured (IPEEE page 7-2).
IPEEE-TER Page xii Pages 2, 26, 43	Operator error rates for control room fires are highly optimistic, etc.	The most reliable operator action is used for only those fire scenarios where the control room remains habitable and equipment needed for immediate plant control is operating successfully. Also see response to IPEEE request for additional information (RAI) II.1.
IPEEE-TER Page xii Pages 2, 19, 43	Heat release rate for cabinet fire not representative.	No action to be taken as it does not appear to impact the analysis conclusions.
IPEEE-TER Pages 2, 27	Seismic fires due to weakly anchored cabinets not addressed.	There are no known weakly anchored electrical cabinets at NMP2.
IPEEE-TER Page 7	Stuck open safety relief valve (SRV) and Large LOCA not addressed.	A stuck open SRV with RCIC success guarantees successful reactor vessel isolation (nitrogen is not needed) and allows low pressure injection success. Therefore, the stuck open SRV event improves the number and reliability of success paths and is an insignificant risk contributor. Also, medium and large LOCAs due to pipe breaks are incorporated in the 0.5g HCLPF fragility in the PRA model.

Table 2 (Continued)

Item[1]	Comment	Response/Disposition
IPEEE-TER Page 8	Standby Liquid Control (SLC) system seismic capacity.	The Reactor Protection System (RPS) system is very reliable with significant redundancy built into the function. Because of this, the Redundant Reactivity Control System (RRCS) and SLC system need not be "safety related" nor "seismic Category I" under the Regulations. The 0.5g HCLPF fragility in the PRA model incorporates RPS seismic failure. The frequency of seismic initiator and failure of RPS (non-seismic) during seismic initiating event is low in the PRA. Given this low risk and dependency on the operators in the Anticipated Transients Without Scram (ATWS) model, no RRCS or SLC seismic evaluations are needed.
IPEEE-TER Page 9	HEP of 0.01 for depressurization equates to unreliability of all low pressure injection.	Depressurization is redundant to RCIC and HPCS for the 0.23 HCLPF success paths. This is included in the PRA.
IPEEE-TER Page 9	SBO procedure modification needed relative to depressurization and minimizing depletion of nitrogen.	Emergency Operating Procedures (EOPs) address how to conserve nitrogen; specifically, EOP-RPV and EOP-C3. Special Operating Procedures SOP-1 and SOP-2 have specific actions on how to conserve battery power. Separate criteria are given for blackout in lieu of the normal heat capacity temperature limits (HCTL) in EOP-6 Section 29.
IPEEE-TER Page 11	Consideration of human actions in the SMA not entirely in keeping with SMA guidance.	Compliance with SMA is believed to be in the IPEEE. The TER states that seismic PRA fully considered human actions and suggests safety significance is low.
IPEEE-TER Page 13	Consideration of piping degradation (e.g., wear) and impact on seismic flooding risk not included.	The 0.5g HCLPF fragility in the PRA incorporates this risk. The probability of degradation below this seismic capacity is negligible.
IPEEE-TER Page 27	No dependency matrix was provided and plant unique phenomena were not addressed.	NMP response to NRC questions provided IPE dependency matrix. No other important or unique dependencies or phenomena were identified.
IPEEE-TER Page 35, 36	Approach to identifying other external events was not comprehensive.	NMP did consider other external hazards listed in the PRA procedures guide. This was not documented because it was not requested by the IPEEE scope.
IPEEE-TER Page 36	Little detail provided on systems interactions.	NMP believes that the present effort is reasonable.

Table 2 (Continued)

Item[1]	Comment	Response/Disposition
IPEEE-TER Page 36	No specific information was provided concerning smoke impact on fire fighting effectiveness.	Smoke can affect fire fighting effectiveness and this is considered in training, etc.
IPEEE-TER Page 43	Seismic hazard assessment was truncated at 1.02g.	This will not impact the results, but will be considered in a future update.

Note: (1) SE = NRC Safety Evaluation (Enclosure 1 to NRC letter); TER = Technical Evaluation Report (Enclosure 2 to NRC letter)

Table 3
Baseline CDF – Highest-Ranked Cutsets
(CDF_{Base} = 3.6E-06)

#	Cutset Probability	Event Probability	Event	Description
1	1.93E-07	1.93E-04	%FCR0	Fire - Control Room (Loss of Feedwater (FW) & Condensate (CN))
		1.00E-03	ZHRA1_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
2	1.93E-07	1.93E-04	%FCR0	Fire - Control Room (Loss of FW & CN)
		1.00E-02	ZHRA2_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
		1.00E-01	ZCR2_CROPERATOR	MCR Uninhabitable for FCR0 Fire
3	1.51E-07	8.08E-03	%SWPX	Loss of 2 Normally Running Service Water Pumps
		1.86E-05	ZQSWH_DEPOPRATOR	Dependent Operator Failure to Control Service Water and Open Room Doors (HVAC)
4	1.03E-07	1.14E-01	%MSIV	MSIV Isolation
		9.00E-07	ZQDHR_DEPOPRATOR	Dependent Operator Failure to Align Containment Heat Removal
5	1.01E-07	1.01E-05	%FCR2	Fire - Control Room (KAF*KBF*HSF)
		1.00E-02	ZHRA2_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
6	1.01E-07	1.01E-05	%FCR3	Fire - Control Room (KAF*KBF*HSF)
		1.00E-02	ZHRA2_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
7	9.25E-08	3.56E-04	%LKX	Loss of Lake Intake
		5.00E-02	ZZOHX_DHRRECVRY	Failure to Recover Loss of Decay Heat Removal (DHR) Prior to Containment Failure
		1.30E-02	ZCV02_CVOPERATOR	Operators Fail to Align Containment Venting when Air or Div I AC Unavail
		4.00E-01	ZZZ48CFXHSFAILAX	Containment Failure Below Suppression Pool Water Level
8	7.75E-08	8.61E-02	%LOF	Loss of Feedwater
		9.00E-07	ZQDHR_DEPOPRATOR	Dependent Operator Failure to Align Containment Heat Removal
9	6.50E-08	8.01E-03	%A1X	Loss of Division I AC
		1.86E-05	ZQSWH_DEPOPRATOR	Dependent Operator Failure to Control Service Water and Open Room Doors (HVAC)
		6.60E-01	YSWR3_SWPXP1CRUN	2SWP*P1C Pump is Running
		6.60E-01	YSWR1_SWPXP1ARUN	2SWP*P1A Pump is Running
10	6.50E-08	8.01E-03	%A1X	Loss of Division I AC
		1.86E-05	ZQSWH_DEPOPRATOR	Dependent Operator Failure to Control Service Water and Open Room Doors (HVAC)
		6.60E-01	YSWR3_SWPXP1CRUN	2SWP*P1C Pump is Running
		6.60E-01	YSWR5_SWPXP1ERUN	2SWP*P1E Pump is Running

Table 4
Baseline LERF – Highest-Ranked Cutsets
($LERF_{Base}$ = 4.1E-07)

#	Cutset Probability	Event Probability	Event	Description
1	5.23E-08	5.71E-06	%SEIS4	Seismic from 0.25 to 0.51
		9.16E-03	ZZC14_SEISCOMP14	Seismic Induced Common Cause Failure (CCF) of Plant Equipment - Quake Level 4
2	4.68E-08	4.69E-07	%SEIS5	Seismic from 0.51 to 0.71
		9.97E-02	ZZC15_SEISCOMP15	Seismic Induced CCF of Plant Equipment - Quake Level 5
3	3.82E-08	1.32E-07	%SEIS6	Seismic from 0.71 to 1.019
		2.88E-01	ZZC16_SEISCOMP16	Seismic Induced CCF of Plant Equipment - Quake Level 6
4	8.89E-09	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		8.05E-01	ZZIRL_AC-IR-LT	Failure to Recover AC Prior to Vessel Failure, Late Core Damage Sequence
		9.00E-01	ZZS-PCH1S	Portable Charging Successful in SBO
		1.00E+00	ZIS05	Operator Fails to Locally Close MOVs (SBOE) Given Fire Initiator
		1.00E+00	ZOSVL1_SOPERATOR	Operators Fail to Align SRV Nitrogen Supply SOVs to UPS AC Supply
		5.80E-03	WA301EDG1MAINTUN	2EGS*EG1 Div I Emergency Diesel Generator Maintenance Unavailability
		1.00E+00	DFRXMOVOUTPOWER	Outboard Isolation MOV Fails to Close (Loss of Power)
		1.00E+00	DFRXMOVIN-POWER	Inboard Isolation MOV Fails to Close (Loss of Power)
5	5.02E-09	9.20E-01	%ISLOCA	Interfacing Systems LOCA
		5.00E-02	ZZZR3_RHRRUPTURE	Pipe or Heat Exchanger Rupture in RHR Given ISLOCA
		3.90E-04	RHSMOV24BO_VMZN1	2RHS*MOV24B Spuriously Opens
		2.80E-04	ZZOCV_RHSAOV16BO	2RHS*AOV16B Sticks Open after Testing
		1.00E+00	ZZRB2_RB-02-01OO	Reactor Building Enclosure Sustains Structural Damage
6	5.02E-09	9.20E-01	%ISLOCA	Interfacing Systems LOCA
		5.00E-02	ZZZR3_RHRRUPTURE	Pipe or Heat Exchanger Rupture in RHR Given ISLOCA
		3.90E-04	RHSMOV40BO_VMZN1	2RHS*MOV40B Spuriously Opens
		2.80E-04	ZZOCV_RHSV39BOOO	2RHS*V39B Sticks Open after Testing
		1.00E+00	ZZRB2_RB-02-01OO	Reactor Building Enclosure Sustains Structural Damage
7	4.84E-09	9.20E-01	%ISLOCA	Interfacing Systems LOCA
		5.00E-02	ZZZR3_RHRRUPTURE	Pipe or Heat Exchanger Rupture in RHR Given ISLOCA
		3.90E-04	RHSMOV24BO_VMZN1	2RHS*MOV24B Spuriously Opens
		2.70E-04	RHSAOV16BO_VCZG1	2RHS*AOV16B Fails
		1.00E+00	ZZRB2_RB-02-01OO	Reactor Building Enclosure Sustains Structural Damage
8	4.84E-09	9.20E-01	%ISLOCA	Interfacing Systems LOCA
		5.00E-02	ZZZR3_RHRRUPTURE	Pipe or Heat Exchanger Rupture in RHR Given ISLOCA
		3.90E-04	RHSMOV40BO_VMZN1	2RHS*MOV40B Spuriously Opens
		2.70E-04	RHSV39BOOO_VCZG1	2RHS*V39B Fails
		1.00E+00	ZZRB2_RB-02-01OO	Reactor Building Enclosure Sustains Structural Damage
9	3.85E-09	1.34E-02	%SEIS1	Seismic from 0.01 to 0.05
		2.87E-07	ZZC11_SEISCOMP11	Seismic Induced CCF of Plant Equipment - Quake Level 1

Table 5
Division 1 DG Unavailable and Compensatory Measures – Highest-Ranked Cutsets for CDF
(CDF_{1Out} = 9.2E-06)

#	Cutset Probability	Event Probability	Event	Description
1	2.12E-07	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		1.00E-01	ZPAC1_COPERATOR	Operator Fails to Align Portable Charger - DC Load Shedding Successful
2	2.12E-07	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		1.00E-01	ZZPAC_PORTCHGRGR	Portable Generator Fails to Operate
3	1.93E-07	1.93E-04	%FCR0	Fire - Control Room (Loss of FW & CN)
		1.00E-03	ZHRA1_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
4	1.93E-07	1.93E-04	%FCR0	Fire - Control Room (Loss of FW & CN)
		1.00E-02	ZHRA2_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
		1.00E-01	ZCR2_CROPERATOR	MCR Uninhabitable for FCR0 Fire
5	1.90E-07	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		1.00E-01	ZOSVL1_SOPERATOR	Operators Fail to Align SRV Nitrogen Supply SOVs to UPS AC Supply
		9.00E-01	ZZS-PCH1S	Portable Charging Successful in SBO
6	1.90E-07	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		9.00E-01	ZZS-PCH1S	Portable Charging Successful in SBO
		1.00E-01	ZCV05_CVOPERATOR	Operator Fails to Perform SBO Vent (Local Actions including LAC-VBS Alignment)
7	1.51E-07	8.08E-03	%SWPX	Loss of 2 Normally Running Service Water Pumps
		1.86E-05	ZQSWH_DEPOPRATOR	Dependent Operator Failure to Control Service Water and Open Room Doors (HVAC)

Table 6
Division 1 DG Unavailable and Compensatory Measures – Highest-Ranked Cutsets for LERF
($LERF_{1Out}$ = 9.0E-07)

#	Cutset Probability	Event Probability	Event	Description
1	5.87E-08	1.01E-05	%FCR1	Fire - Control Room (KAF*KBF*HSF)
		1.00E-01	ZZZ60_DGMOVCABLE	Control Room Fire Fails EDG MOV Cable Before EDG Can Start
		5.80E-02	ZA301DCRDOOR	Operator Fails to Manually Open EDG Room Door or Supply MOV
2	5.23E-08	5.71E-06	%SEIS4	Seismic from 0.25 to 0.51
		9.16E-03	ZZC14_SEISCOMP14	Seismic Induced CCF of Plant Equipment - Quake Level 4
3	4.68E-08	4.69E-07	%SEIS5	Seismic from 0.51 to 0.71
		9.97E-02	ZZC15_SEISCOMP15	Seismic Induced CCF of Plant Equipment - Quake Level 5
4	3.82E-08	1.32E-07	%SEIS6	Seismic from 0.71 to 1.019
		2.88E-01	ZZC16_SEISCOMP16	Seismic Induced CCF of Plant Equipment - Quake Level 6
5	1.70E-08	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		1.00E-01	ZIS05	Operator Fails to Locally Close MOVs (SBOE) Given Fire Initiator
		8.05E-01	ZZIRL_AC-IR-LT	Failure to Recover AC Prior to Vessel Failure, Late Core Damage Sequence
		1.00E-01	ZPAC1_COPERATOR	Operator Fails to Align Portable Charger - DC Load Shedding Successful
		1.00E+00	DFRXMOVOUTPOWER	Outboard Isolation MOV Fails to Close (Loss of Power)
		1.00E+00	DFRXMOVIN-POWER	Inboard Isolation MOV Fails to Close (Loss of Power)
6	1.70E-08	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		1.00E-01	ZIS05	Operator Fails to Locally Close MOVs (SBOE) Given Fire Initiator
		8.05E-01	ZZIRL_AC-IR-LT	Failure to Recover AC Prior to Vessel Failure, Late Core Damage Sequence
		1.00E-01	ZZPAC_PORTCHGRGR	Portable Generator Fails to Operate
		1.00E+00	DFRXMOVOUTPOWER	Outboard Isolation MOV Fails to Close (Loss of Power)
		1.00E+00	DFRXMOVIN-POWER	Inboard Isolation MOV Fails to Close (Loss of Power)
7	1.53E-08	2.12E-06	%FA18B	Fire - FA18 (337NW,359NW,377NW) Suppression Failure
		1.00E-01	ZIS05	Operator Fails to Locally Close MOVs (SBOE) Given Fire Initiator
		8.05E-01	ZZIRL_AC-IR-LT	Failure to Recover AC Prior to Vessel Failure, Late Core Damage Sequence
		1.00E-01	ZOSVL1_SOPERATOR	Operators Fail to Align SRV Nitrogen Supply SOVs to UPS AC Supply
		9.00E-01	ZZS-PCH1S	Portable Charging Successful in SBO
		1.00E+00	DFRXMOVOUTPOWER	Outboard Isolation MOV Fails to Close (Loss of Power)
		1.00E+00	DFRXMOVIN-POWER	Inboard Isolation MOV Fails to Close (Loss of Power)
8	1.27E-08	1.01E-05	%FCR1	Fire - Control Room (KAF*KBF*HSF)
		2.96E-01	ZZDG8_RECEDG8HOR	Failure to Recover EDG within 8 Hours in SBO
		4.24E-03	EGSXEG3XXXXGAZR2	2EGS*EG3 Div II Emergency Diesel Generator Fails To Run after 1st hour
9	1.18E-08	1.01E-05	%FCR1	Fire - Control Room (KAF*KBF*HSF)
		2.96E-01	ZZDG8_RECEDG8HOR	Failure to Recover EDG within 8 Hours in SBO
		3.95E-03	EGSXEG3XXXXGAZS1	2EGS*EG3 Div II Emergency Diesel Generator Fails To Start

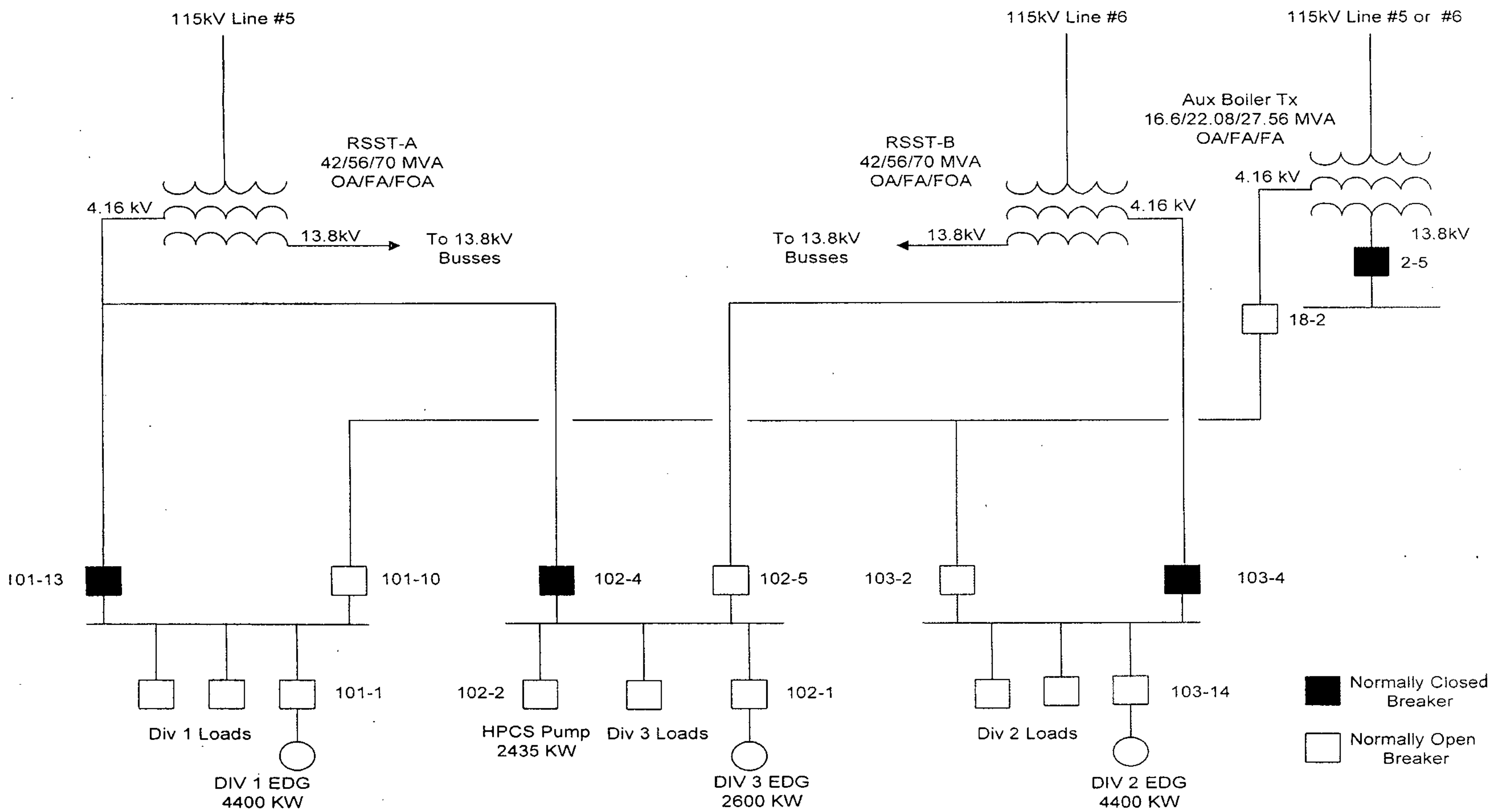
Table 7
Division 2 DG Unavailable and Compensatory Measures – Highest-Ranked Cutsets for CDF
(CDF_{2Out} = 1.2E-05)

#	Cutset Probability	Event Probability	Event	Description
1	1.36E-06	3.85E-02	%LOSP	Loss of Offsite Power Initiating Event
		1.00E-01	ZHS03_HSDGOPERTR	Operator Fails to Align Fire Water for EDG Cooling
		7.31E-01	ZZOGR1_RECOGR1HR	Failure of Offsite Power Recovery in 30 minutes - LOSP Initiator
		4.84E-04	BYSXBAT2AXXBBZD1	2BYS*BAT2A Battery Fails on Demand
2	2.12E-07	2.12E-06	%FA16B	Fire - FA16 (332NW,352NW,371NW) Suppression Failure
		1.00E-01	ZHS03_HSDGOPERTR	Operator Fails to Align Fire Water for EDG Cooling
3	1.93E-07	1.93E-04	%FCR0	Fire - Control Room (Loss of FW & CN)
		1.00E-03	ZHRA1_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
4	1.93E-07	1.93E-04	%FCR0	Fire - Control Room (Loss of FW & CN)
		1.00E-02	ZHRA2_HROPERATOR	Operators Fail to Successfully Respond to Control Room Fire
		1.00E-01	ZCR2_CROPERATOR	MCR Uninhabitable for FCR0 Fire
5	1.71E-07	2.12E-06	%FA16B	Fire - FA16 (332NW,352NW,371NW) Suppression Failure
		9.00E-01	ZZS-PCH1S	Portable Charging Successful in SBO
		9.00E-01	ZZS-HSS	HPCS Successful in SBO
		1.00E-01	ZCV05_CVOPERATOR	Operator Fails to Perform SBO Vent (Local Actions including LAC-VBS Alignment)
6	1.51E-07	8.08E-03	%SWPX	Loss of 2 Normally Running Service Water Pumps
		1.86E-05	ZQSWH_DEPOPRATOR	Dependent Operator Failure to Control Service Water and Open Room Doors (HVAC)
7	1.36E-07	3.85E-02	%LOSP	Loss of Offsite Power Initiating Event
		1.00E-02	ZHS05_HSROOMCOL	Operator Fails to Open HPCS Room Doors and HVAC Duct
		7.31E-01	ZZOGR1_RECOGR1HR	Failure of Offsite Power Recovery in 30 minutes - LOSP Initiator
		4.84E-04	BYSXBAT2AXXBBZD1	2BYS*BAT2A Battery Fails on Demand
8	1.36E-07	3.85E-02	%LOSP	Loss of Offsite Power Initiating Event
		1.00E-02	ZHS06_HPCSLV8SBO	Operator Fails to Allow HPCS to Run for Init Level Restoration in SBO
		7.31E-01	ZZOGR1_RECOGR1HR	Failure of Offsite Power Recovery in 30 minutes - LOSP Initiator
		1.00E+00	ZHS01_HPCSOPERAT	Operator Fails to Align Div III (EDG2) to Alt. Div. Given SBO
		4.84E-04	BYSXBAT2AXXBBZD1	2BYS*BAT2A Battery Fails on Demand
9	1.27E-07	3.85E-02	%LOSP	Loss of Offsite Power Initiating Event
		5.00E-02	ZZOHX_DHRRECVRY	Failure to Recover Loss of DHR Prior to Containment Failure
		1.00E-01	ZCV06_PPSWPCVENT	Operator Fails to Vent PC (Local Actions including use of Port. Power Pack)
		4.00E-01	ZZZ48CFXHSFAILAX	Containment Failure Below Suppression Pool Water Level
		7.31E-01	ZZOGR1_RECOGR1HR	Failure of Offsite Power Recovery in 30 minutes - LOSP Initiator
		2.26E-03	RHSXP1AXXXXPE1S1	2RHS*P1A RHR A Pump Fails To Start

Table 8
Division 2 DG Unavailable and Compensatory Measures – Highest-Ranked Cutsets for LERF
($LERF_{2Out}$ = 1.0E-06)

#	Cutset Probability	Event Probability	Event	Description
1	9.79E-08	3.85E-02	%LOSP	Loss of Offsite Power Initiating Event
		1.00E-01	ZIS03_SBOE-FAIL-	Operator Fails to Locally Close MOVs (SBOE)
		7.19E-01	ZZIRE_AC-IR-OIF	Failure to Recover AC Prior to Vessel Failure, Early Core Damage Sequence
		1.00E-01	ZHS03_HSDGOPERTR	Operator Fails to Align Fire Water for EDG Cooling
		7.31E-01	ZZOGR1_RECOGR1HR	Failure of Offsite Power Recovery in 30 minutes - LOSP Initiator
		4.84E-04	BYSXBAT2AXXBBZD1	2BYS*BAT2A Battery Fails on Demand
		1.00E+00	DFRXMOVOUTPOWER	Outboard Isolation MOV Fails to Close (Loss of Power)
		1.00E+00	DFRXMOVIN-POWER	Inboard Isolation MOV Fails to Close (Loss of Power)
2	5.23E-08	5.71E-06	%SEIS4	Seismic from 0.25 to 0.51
		9.16E-03	ZZC14_SEISCOMP14	Seismic Induced CCF of Plant Equipment - Quake Level 4
3	4.68E-08	4.69E-07	%SEIS5	Seismic from 0.51 to 0.71
		9.97E-02	ZZC15_SEISCOMP15	Seismic Induced CCF of Plant Equipment - Quake Level 5
4	3.82E-08	1.32E-07	%SEIS6	Seismic from 0.71 to 1.019
		2.88E-01	ZZC16_SEISCOMP16	Seismic Induced CCF of Plant Equipment - Quake Level 6
5	2.12E-08	2.12E-06	%FA16B	Fire - FA16 (332NW,352NW,371NW) Suppression Failure
		1.00E-01	ZIS05	Operator Fails to Locally Close MOVs (SBOE) Given Fire Initiator
		1.00E-01	ZHS03_HSDGOPERTR	Operator Fails to Align Fire Water for EDG Cooling
		1.00E+00	DFRXMOVOUTPOWER	Outboard Isolation MOV Fails to Close (Loss of Power)
		1.00E+00	DFRXMOVIN-POWER	Inboard Isolation MOV Fails to Close (Loss of Power)
6	1.27E-08	1.01E-05	%FCR1	Fire - Control Room (KAF*KBF*HSF)
		2.96E-01	ZZDG8_RECEDG8HOR	Failure to Recover EDG within 8 Hours in SBO
		4.24E-03	EGSXEG1XXXXGAZR2	2EGS*EG1 Div I Emergency Diesel Generator Fails To Run After 1st hour
7	1.18E-08	1.01E-05	%FCR1	Fire - Control Room (KAF*KBF*HSF)
		2.96E-01	ZZDG8_RECEDG8HOR	Failure to Recover EDG within 8 Hours in SBO
		3.95E-03	EGSXEG1XXXXGAZS1	2EGS*EG1 Div I Emergency Diesel Generator Fails To Start

Figure 1: Simplified One Line Diagram – NMP2 Emergency 4.16 kV Distribution



ATTACHMENT 1

LIST OF REGULATORY COMMITMENTS

The following table identifies the regulatory commitments in this document. Any other statements in this submittal represent intended or planned actions. They are provided for information purposes and are not considered to be regulatory commitments.

REGULATORY COMMITMENT	SCHEDULED COMPLETION DATE
1. Complete the modification and associated implementing procedures to provide the Division 3 DG with a source of backup cooling water from the fire protection water supply system and its associated diesel-driven fire water pumps.	90 days following NRC approval of the license amendment request.
2. Prepare or revise appropriate procedures to include provisions for implementing compensatory measures and configuration risk management controls when entering an extended DG CT (greater than 72 hours and up to 14 days), including the following: a. The other two DGs are operable and no planned maintenance or testing activities are scheduled on those two DGs. b. No planned maintenance or testing activities are scheduled in Scriba Substation, the NMP2 115 kV switchyard, or on the 115 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability. c. The HPCS system is available and no planned maintenance or testing activities are scheduled. d. The RCIC system is available and no planned maintenance or testing activities are scheduled. e. The NMP2 and NMP1 diesel-driven fire pumps and the cross-tie between the NMP2 and NMP1 fire protection water supply systems are available to provide a backup cooling water supply to the Division 3 DG and no planned maintenance or testing activities are scheduled. f. The Division 1 and Division 2 residual heat removal (RHR) pumps and the low pressure core spray (LPCS) pump are available and no planned maintenance or testing activities are scheduled. g. Both divisions of the redundant reactivity control system and the standby liquid control system (equipment required for mitigation of anticipated transients without scram (ATWS) events) are available and no planned maintenance or testing activities are scheduled. h. The stability of existing and projected grid conditions will be confirmed prior to planned entry into the extended DG CT by contacting the transmission system operator (TSO).	90 days following NRC approval of the license amendment request.

REGULATORY COMMITMENT	SCHEDULED COMPLETION DATE
i. Operating crews will be briefed on the DG work plan. As a minimum, the briefing will include the following important procedural actions that could be required in the event a LOOP, SBO, or fire condition occurs: – Alignment of the fire protection water supply system to provide cooling water to the Division 3 DG. – Establishing the cross-connection to allow the Division 3 DG to power either Division 1 or Division 2 loads. – Utilizing the portable generator as a backup source of AC power to one of the Division 1 or Division 2 battery chargers. – Utilizing the portable power supplies to maintain operability of the SRVs. – Closing containment isolation valves in the drywell floor drain and equipment drain lines. j. The extended DG CT will not be entered for planned maintenance if severe weather conditions with the potential to degrade or limit offsite power availability are present or are predicted to occur. k. Except for the room housing the inoperable DG, no hot work permits will be active for the control building or the normal switchgear rooms. l. Transient combustible loading in the impacted fire zones will be reviewed and any unnecessary transient combustibles will be removed. m. The fire detection and fire suppression equipment in the impacted fire zones is functional or if not functional, equivalent compensatory measures are implemented in accordance with the fire protection program. n. A portable generator is available as a temporary backup source of AC power to one of the Division 1 or Division 2 battery chargers and is pre-staged within the protected area near the NMP2 control building.	

ATTACHMENT 2

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

The current versions of the following NMP2 Technical Specification pages have been marked-up by hand to reflect the proposed changes:

3.8.1-2
3.8.1-3

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one division concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours <u>AND</u> 24 hours from discovery of both HPCS and Low Pressure Core Spray (LPCS) Systems with no offsite power <u>AND</u> 17 6 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	<u>AND</u>		Insert 1
	B.4	Restore required DG to OPERABLE status.	~~72 hours~~ ~~AND~~ ~~6 days from discovery of failure to meet LCO~~

(continued)

<u>INSERT 1</u> (for TS page 3.8.1-3)

72 hours from
discovery of
an inoperable
Division 3 DG

<u>AND</u>

14 days

<u>AND</u>

17 days from
discovery of
failure to meet
LCO

ATTACHMENT 3

CHANGES TO TECHNICAL SPECIFICATION BASES (MARK-UP)

The current versions of the following NMP2 Technical Specification Bases pages have been marked-up by hand to reflect the proposed changes. These Bases pages are provided for information only.

B 3.8.1-8
B 3.8.1-10
B 3.8.1-11

BASES

ACTIONS

A.3 (continued)

The Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

The third Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to ~~72 hours~~ 14 days. This situation could lead to a total of ~~144 hours~~ 17 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional ~~72 hours~~ 14 days (for a total of ~~6~~ 31 days) allowed prior to complete restoration of the LCO. The ~~6~~ 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and ~~6~~ 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive must be met.

Similar to Required Action A.2, the Completion Time of Required Action A.3 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of at the time that Condition A was entered.

B.1

To ensure a highly reliable power source remains, it is necessary to verify the availability of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

(continued)

BASES

ACTIONS

B.2 (continued)

required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition E or G of LCO 3.8.1 is entered, as applicable. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the Deficiency Event Report Program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 9), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

Condition B

~~According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition B for a period that should not exceed 72 hours.~~ In ~~this condition~~, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

Insert A

Insert B

(continued)

BASES

ACTIONS

B.4 (continued)

The ~~second~~ third Completion Time for Required Action B.4 established a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This situation could lead to a total of ~~144 hours~~ 17 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of ~~9~~ 20 days) allowed prior to complete restoration of the LCO. The ~~6~~ 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the ~~72 hour and 6 day~~ Completion Times means that ~~both~~ the three Completion Times apply simultaneously, and the ~~more~~ most restrictive Completion Time must be met.

Similar to Required Action B.2, the Completion Time of Required Action B.4 allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This exception results in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of concurrent failure of redundant required features. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with only one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 8) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions (i.e.,

(continued)

INSERT A (for TS Bases page B 3.8.1-10)

Although Condition B applies to a single inoperable DG, several Completion Times are specified for this Condition.

The first Completion Time applies to an inoperable Division 3 DG.

INSERT B (for TS Bases page B 3.8.1-10)

This Completion Time begins only "upon discovery of an inoperable Division 3 DG" and, as such, provides an exception to the normal "time zero" for beginning the allowed outage time "clock" (i.e., for beginning the clock for an inoperable Division 3 DG when Condition B may have already been entered for another equipment inoperability and is still in effect).

The second Completion Time (14 days) applies to an inoperable Division 1 or Division 2 DG and is a risk-informed Completion Time based on a plant-specific risk analysis. The extended Completion Time would typically be used for voluntary planned maintenance or inspections but can also be used for corrective maintenance. However, use of the extended Completion Time for voluntary planned maintenance should be limited to once within an operating cycle (24 months) for each DG (Division 1 and Division 2). When utilizing an extended DG Completion Time (greater than 72 hours and up to 14 days), the compensatory measures and configuration risk management controls listed below shall be implemented. For planned maintenance utilizing an extended Completion Time, these measures and controls shall be implemented prior to entering Condition B. For an unplanned entry into an extended Completion Time, these measures and controls shall be implemented without delay.

1. The other two DGs are operable and no planned maintenance or testing activities are scheduled on those two DGs.

2. No planned maintenance or testing activities are scheduled in Scriba Substation, the NMP2 115 kV switchyard, or on the 115 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability.

3. The HPCS system is available and no planned maintenance or testing activities are scheduled.

4. The RCIC system is available and no planned maintenance or testing activities are scheduled.

5. The NMP2 and NMP1 diesel-driven fire pumps and the cross-tie between the NMP2 and NMP1 fire protection water supply systems are available to provide a backup cooling water supply to the Division 3 DG and no planned maintenance or testing activities are scheduled.

INSERT B (continued)

6. The Division 1 and Division 2 residual heat removal (RHR) pumps and the low pressure core spray (LPCS) pump are available and no planned maintenance or testing activities are scheduled.

7. Both divisions of the redundant reactivity control system and the standby liquid control system (equipment required for mitigation of anticipated transients without scram (ATWS) events) are available and no planned maintenance or testing activities are scheduled.

8. The stability of existing and projected grid conditions will be confirmed prior to planned entry into the extended DG CT by contacting the transmission system operator (TSO).

9. Operating crews will be briefed on the DG work plan. As a minimum, the briefing will include the important procedural actions that could be required in the event a LOOP, SBO, or fire condition occurs.

10. The extended DG CT will not be entered for planned maintenance if severe weather conditions with the potential to degrade or limit offsite power availability are present or are predicted to occur.

11. Except for the room housing the inoperable DG, no hot work permits will be active for the control building or the normal switchgear rooms.

12. Transient combustible loading in the impacted fire zones will be reviewed and any unnecessary transient combustibles will be removed.

13. The fire detection and fire suppression equipment in the impacted fire zones is functional or if not functional, equivalent compensatory measures are implemented in accordance with the fire protection program.

14. A portable generator is available as a temporary backup source of AC power to one of the Division 1 or Division 2 battery chargers and is pre-staged within the protected area near the NMP2 control building.