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

October 31, 2011

Mr. Kenneth Langdon
Vice President Nine Mile Point
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

SUBJECT: NINE MILE POINT NUCLEAR STATION, UNIT NO. 2 - ISSUANCE OF AMENDMENT REGARDING EXTENSION OF COMPLETION TIME FOR AN INOPERABLE DIVISION 1 OR DIVISION 2 DIESEL GENERATOR (TAC NO. ME3736)

Dear Mr. Langdon:

The Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 138 to Renewed Facility Operating License No. NPF-69 for the Nine Mile Point Nuclear Station, Unit No. 2 (NMP2), in response to your application dated March 30, 2010, as supplemented on June 1, 2010, December 29, 2010, January 14, 2011, February 25, 2011, April 27, 2011, and July 25, 2011. The proposed amendment would modify NMP2 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 from 72 hours to 14 days. The proposed amendment represents a risk-informed licensing change.

A copy of the related Safety Evaluation is enclosed. A Notice of Issuance will be included in the Commission's next regular biweekly *Federal Register* notice.

Sincerely,

RGuzman

Richard V. Guzman, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-410

Enclosures:
1. Amendment No. 138 to NPF-69
2. Safety Evaluation

cc w/encls: Distribution via Listserv

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

NINE MILE POINT NUCLEAR STATION, LLC (NMPNS)

DOCKET NO. 50-410

NINE MILE POINT NUCLEAR STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 138
Renewed License No. NPF-69

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Nine Mile Point Nuclear Station, LLC (the licensee) dated March 30, 2010, as supplemented on June 1, 2010, December 29, 2010, January 14, 2011, February 25, 2011, April 27, 2011, and July 25, 2011, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-69 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, as revised through Amendment No. 138 are hereby incorporated into this license. Nine Mile Point Nuclear Station, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 90 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Douglas V Pickett
for

Nancy L. Salgado, Chief
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the License and Technical Specifications

Date of Issuance: October 31, 2011

ATTACHMENT TO LICENSE AMENDMENT NO. 138

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-69

DOCKET NO. 50-410

Replace the following page of the Renewed Facility Operating License with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

Remove Page	Insert Page
4	4

Replace the following pages of Appendix A, Technical Specifications, with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages
3.8.1-2	3.8.1-2
3.8.1-3	3.8.1-3

(1) Maximum Power Level

Nine Mile Point Nuclear Station, LLC is authorized to operate the facility at reactor core power levels not in excess of 3467 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, as revised through Amendment No. 138 are hereby incorporated into this license. Nine Mile Point Nuclear Station, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Fuel Storage and Handling (Section 9.1, SSER 4)*

a. Fuel assemblies, when stored in their shipping containers, shall be stacked no more than three containers high.

b. When not in the reactor vessel, no more than three fuel assemblies shall be allowed outside of their shipping containers or storage racks in the New Fuel Vault or Spent Fuel Storage Facility.

c. The above three fuel assemblies shall maintain a minimum edge-to-edge spacing of twelve (12) inches from the shipping container array and approved storage rack locations.

d. The New Fuel Storage Vault shall have no more than ten fresh fuel assemblies uncovered at any one time.

(4) Turbine System Maintenance Program (Section 3.5.1.3.10, SER)

The operating licensee shall submit for NRC approval by October 31, 1989, a turbine system maintenance program based on the manufacturer's calculations of missile generation probabilities. (Submitted by NMPC letter dated October 30, 1989 from C.D. Terry and approved by NRC letter dated March 15, 1990 from Robert Martin to Mr. Lawrence Burkhardt, III).

* The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report (SER) and/or its supplements wherein the license condition is discussed.

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)
	AND		
	A.3	Restore required offsite circuit to OPERABLE status.	72 hours AND 24 hours from discovery of both HPCS and Low Pressure Core Spray (LPCS) Systems with no offsite power AND 17 days from discovery of failure to meet LCO
B. One required DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	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>		
	B.4	Restore required DG to OPERABLE status.	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

(continued)

UNITED STATES
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WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 138

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-69

NINE MILE POINT NUCLEAR STATION, LLC

NINE MILE POINT NUCLEAR STATION, UNIT NO. 2

DOCKET NO. 50-410

1.0 INTRODUCTION

By letter dated March 30, 2010 (Agencywide Documents Access Management System (ADAMS) Accession No. ML100900460), as supplemented on June 1, 2010 (ADAMS Accession No. ML101600452), December 29, 2010 (ADAMS Accession No. ML110110165), January 14, 2011 (ADAMS Accession No. ML110250271), February 25, 2011 (ADAMS Accession No. ML110670424), April 27, 2011 (ADAMS Accession No. ML11119A137), and July 25, 2011 (ADAMS Accession No. ML11214A214), Nine Mile Nuclear Station, LLC (NMPNS or the licensee) submitted a license amendment request (LAR) for changes to the Nine Mile Point, Unit No. 2 (NMP2) Technical Specifications (TSs). The proposed amendment would revise 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.

The supplemental letters dated June 1, 2010, December 29, 2010, January 14, 2011, February 25, 2011, April 27, 2011, and July 25, 2011, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the Nuclear Regulatory Commission (NRC or the Commission) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* (FR) on July 13, 2010 (75 FR 39980).

2.0 REGULATORY EVALUATION

The following NRC requirements and guidance are applicable to the NRC staff's review of the licensee's amendment request:

General Design Criterion (GDC) 17, "Electric power systems," of Appendix A, "General Design Criteria for Nuclear Power Plants," to Title 10 of the *Code of Federal Regulations* (10 CFR), Part 50, requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components that are 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. In addition, this criterion requires provisions to minimize the probability of losing electric power from the remaining electric power supplies as a result of loss of power from the unit, the offsite transmission network, or the onsite power supplies.

GDC 18, "Inspection and testing of electric power systems," of Appendix A to 10 CFR Part 50, states, in part, that electric power systems that are important to safety must be designed to permit appropriate periodic inspection and testing of important areas and features, such as insulation and connections to assess the continuity of the systems and the condition of their components.

In 10 CFR 50.36, the Commission established its regulatory requirements related to the content of the TSs. Pursuant to 10 CFR 50.36, TSs are required to include items in the following five specific categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements; (4) design features; and (5) administrative controls. The rule does not specify the particular requirements to be included in a plant's TSs.

As stated in 10 CFR 50.36(c)(2)(i), the "Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met." The LCO Action requirements establish those remedial actions that must be taken when the requirements of an LCO are not met. There are two basic types of Action requirements. The first type specifies a time limit (referred to as an allowed outage time (AOT) or a CT), during which the LCO may not be met. This time limit provides for restoration of an inoperable system or component to operable status or to restore variables to within specified limits. If this type Action requirement is not completed within the specified AOT, a shutdown may be required to place the unit in a mode or condition in which the LCO is not applicable. The second type of Action requirement specifies the remedial measures that permit continued operation of the unit that is not further restricted by the AOT. In this case, compliance with the Action requirements provides an acceptable level of safety for continued operation.

10 CFR 50.63, "Loss of all alternating current power," requires that each light-water cooled nuclear power plant licensed to operate must be able to withstand for a specified duration and recover from a station blackout (SBO).

10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that preventive maintenance activities must not reduce the overall availability of the systems, structures, or components (SSCs). It also requires that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.

Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," dated December 1974 (ADAMS Accession No. ML003740292), provides guidance with respect to operating restrictions (i.e., CTs/AOTs) if the number of available alternating current (AC) sources is less than that required by the TS LCO. In particular, this regulatory guide prescribes a maximum

AOT of 72 hours for an inoperable AC source and 2 hours for two inoperable onsite emergency sources.

RG 1.155, "Station Blackout," dated August 1988 (ADAMS Accession No. ML003740034), describes a method acceptable to the NRC staff for complying with the Commission regulation that requires nuclear power plants to be capable of coping with an SBO event for a specified duration. In RG 1.155, the NRC states that Nuclear Management and Resources Council (NUMARC) 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors" dated November 1987 provides guidance acceptable for meeting the requirements of 10 CFR 50.63, except when RG 1.155 takes precedence over NUMARC 87-00 as indicated in Table 1 of RG 1.155.

RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 1, dated November 2002 (ADAMS Accession No. ML023240437), describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed permanent licensing-basis changes by considering engineering issues and applying risk insights. This RG also provides risk acceptance guidelines for evaluating the results of such evaluations.

RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998 (ADAMS Accession No. ML003740176) describes an acceptable risk-informed approach specifically for assessing proposed permanent TS changes in allowed outage times. This RG also provides risk acceptance guidelines for evaluating the results of such assessments. RG 1.177 identifies a three-tiered approach for the licensees evaluation of the risk associated with a proposed CT TS change, as discussed below.

- Tier 1 assesses the risk impact of the proposed change in accordance with acceptance guidelines consistent with the Commission's Safety Goal Policy Statement, as documented in RG 1.174 and RG 1.177. The first tier assesses the impact on operational plant risk based on the change in core damage frequency (ΔCDF) and change in large early release frequency (ΔLERF). It also evaluates plant risk while equipment covered by the proposed CT is out-of-service, as represented by incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). Tier 1 also addresses probabilistic risk assessment (PRA) quality, including the technical adequacy of the licensee's plant-specific PRA for the subject application. Cumulative risk of the present TS change in light of past related applications or additional applications under review are also considered along with uncertainty/sensitivity analysis with respect to the assumptions related to the proposed TS change.

- Tier 2 identifies and evaluates any potential risk-significant plant equipment outage configurations that could result if equipment, in addition to that associated with the proposed license amendment, is taken out-of-service simultaneously, or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The purpose of this evaluation is to ensure that there are appropriate restrictions in place such that risk-significant plant equipment outage configurations will not occur when equipment associated with the proposed CT is implemented.

- Tier 3 addresses the licensee's overall configuration risk management program (CRMP) to ensure that adequate programs and procedures are in place for identifying risk-significant plant configurations resulting from maintenance or other operational activities and appropriate compensatory measures are taken to avoid risk significant configurations that may not have been considered when the Tier 2 evaluation was performed. Compared with Tier 2, Tier 3 provides additional coverage to ensure risk-significant plant equipment outage configurations are identified in a timely manner and that the risk impact of out of service equipment is appropriately evaluated prior to performing any maintenance activity over extended periods of plant operation. Tier 3 guidance can be satisfied by the Maintenance Rule (10 CFR 50.65(a)(4)), which requires a licensee to assess and manage the increase in risk that may result from activities such as surveillance testing and corrective and preventive maintenance, subject to the guidance provided in RG 1.177, Section 2.3.7.1, and the adequacy of the licensee's program and PRA model for this application. The CRMP is to ensure that equipment removed from service prior to or during the proposed extended CT will be appropriately assessed from a risk perspective.

RG 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 1, dated January 2007 (ADAMS Accession No.: ML070240001), describes an acceptable approach for determining whether the quality of the PRA, in total or the parts that are used to support an application, is sufficient to provide confidence in the results, such that the PRA can be used in regulatory decision-making for light-water reactors.

General guidance for NRC staff evaluation of the technical basis for proposed risk-informed changes is provided in NRC Standard Review Plan (SRP), NUREG-0800, Section 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," dated June 2007 (ADAMS Accession No. ML071700658). Section 19.2 of the SRP states that a risk-informed application should be evaluated by the NRC staff to ensure that the proposed changes meet the following key principles discussed in RG 1.174:

- The proposed change meets the current regulations, unless it explicitly relates to a requested exemption.

- The proposed change is consistent with the defense-in-depth philosophy.

- The proposed change maintains sufficient safety margins.

- When proposed changes increase CDF or risk, the increase(s) should be small and consistent with the intent of the Commission's Safety Goal Policy Statement (reference, "Safety Goals for the Operation of Nuclear Power Plants; Policy Statement; Correction and Republication," 51 FR 30028, dated August 21, 1986).

- The impact of the proposed change should be monitored using performance measurement strategies.

Guidance for NRC staff evaluation of PRA technical adequacy is provided in SRP Section 19.1, "Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 1, dated September 2006 (ADAMS Accession No. ML062510220)

More specific NRC staff guidance related to risk-informed TS changes is provided in SRP Section 16.1, "Risk-Informed Decisionmaking: Technical Specifications," Revision 0, dated August 1998, (ADAMS Accession No. ML042520260), which includes AOT changes as part of risk-informed decision-making.

NUREG-1784, "Operating Experience Assessment - Effects of Grid Events on Nuclear Power Plant Performance," dated December 2003 (ADAMS Accession No. ML033530400), provided an assessment to identify changes to electric grid performance, relative to nuclear power plants, which could impact safety. The assessment found that major changes related to loss of offsite power (LOOP) events after deregulation compared to before include the following: (1) the frequency of LOOP events at nuclear power plants has decreased; (2) the average duration of LOOP events has increased; (3) where before LOOPs occurred more or less randomly throughout the year, for 1997-2001, most LOOP events occurred during the summer; and (4) the probability of a LOOP as a consequence of a reactor trip has increased.

NUREG/CR-6890, Volumes 1-3, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," dated December 2005 (ADAMS Accession Nos. ML060200477, ML060200479, and ML060200510), analyzed LOOP events and associated SBO core damage risk at U.S. commercial nuclear power plants. The analyses documented in Volume 1 indicated that, on average, LOOP events lasted longer in 1997 - 2004 than in 1986 - 1996.

Draft Branch Technical Position (BTP) 8-8, "Onsite Emergency Diesel Generators and Offsite Power Sources Allowed Outage Extension," [Initial issue for public comments] dated April 25, 2011 (ADAMS Accession No. ML111101603), provides guidance to the NRC staff in reviewing license amendment requests for licensee's proposing a permanent TS change to extend an emergency diesel generator (EDG) AOT beyond 72 hours.

NRC Commission Paper SECY-00-0045, dated February 22, 2000 (ADAMS Accession No. ML003679799), informed the Commission that Nuclear Energy Institute (NEI) guidance document NEI 99-04, "Guidelines for Managing NRC Commitments," offered an acceptable way to manage commitments. SECY-00-0045 also stated that the definitions and other guidance in NEI 99-04 are consistent with the principles described in SECY-98-224. NRC Commission Paper SECY-98-224, "Staff and Industry Activities Pertaining to the Management of Commitments Made by Power Reactor Licensees to the NRC," dated September 28, 1998 (ADAMS Accession No. ML992870043), stated that "[t]he imposition of obligations (sometimes referred to as regulatory requirements) during routine interactions with licensees should be reserved for matters that satisfy the criteria of 10 CFR 50.36 or are otherwise found to be of high safety or regulatory significance." The major distinction between obligations and other parts of the licensing bases is that changes generally cannot be made without prior NRC approval.

TECHNICAL EVALUATION

3.1 Description of NMP2 Electrical Power System

According to the NMP2 Final Safety Analyses Report, there are three 4.16-kV emergency switchgear buses, 2ENS*SWG101, 2ENS*SWG102, and 2ENS*SWG103. Bus 2ENS*SWG101 is dedicated to Division 1 of the Station emergency power distribution system; buses 2ENS*SWG103 and 2ENS*SWG102 are dedicated to Divisions 2 and 3, respectively. Buses 2ENS*SWG101 and 2ENS*SWG103 feed all Station redundant safety-related loads, except the high pressure core spray (HPCS) system loads. The HPCS system loads are fed by bus 2ENS*SWG102.

Offsite power is supplied to the NMP2 switchyard from the transmission network. Two qualified, electrically and physically separated circuits provide AC power to the Division 1, 2, and 3 emergency buses. Offsite power source A from reserve station service transformer A (RSST-A) provides power to the Division 1 emergency bus, and also is the preferred power source for the Division 3 emergency bus. Offsite power source B from reserve station service transformer B (RSST-B) provides power to the Division 2 emergency bus and is also capable of providing power to the Division 3 emergency bus. In addition, either of the Division 1 or Division 2 emergency buses can be powered from a separate emergency backup source through the auxiliary boiler transformer (2ABS-X1). However, certain operating restrictions have to be met prior to the use of the backup source.

The onsite standby power source for each 4.16 kV emergency bus is a dedicated DG. In the event of a LOOP, the engineered safety feature (ESF) loads are automatically connected to the DGs in sufficient time to support safe reactor shutdown and to mitigate the consequences of a design-basis accident (DBA) such as a loss-of-coolant accident (LOCA).

The Division 1 and Division 2 DGs are rated for continuous operation at 4400 kilowatts (kW) for loading conditions expected during a LOOP and DBA or a LOOP with a unit trip. The Division 3 (HPCS) DG is rated for continuous operation at 2600 kW and has a 2000-hour rating of 2850 kW. The Division 3 DG loading conditions include simultaneous LOOP and DBA, and LOOP with a unit trip.

3.2 Description of the Proposed Changes

TS 3.8.1, Condition B (One required DG inoperable), Required Action B.4 CT would be revised to allow either the Division 1 or Division 2 DG to be inoperable for 14 days. The current TS action provides a 72-hour CT for return to service for any of the 3 DGs. The CT for the Division 3 DG would remain at 72 hours. The TS would be revised as follows:

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

TS 3.8.1, Condition A (One required offsite circuit inoperable), Required Action A.3 CT would be revised from 6 days to 17 days, consistent with the proposed 11-day extension of Required

Action B.4. This CT is associated with the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. The TS would be revised as follows:

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

3.3 Deterministic Evaluation

Currently, TS LCO 3.8.1, Action B.4, requires that an inoperable DG must be restored to operable status within 72 hours. In addition, Required Action A.3 and B.4 establish a 6-day limit on the maximum time allowed for any combination of required AC sources to be inoperable during any single contiguous occurrence of failing to meet LCO 3.8.1. If either of these conditions is not met, the plant must be placed in Hot Shutdown within 12 hours and Cold Shutdown within 36 hours.

The licensee has proposed extending the CT for an inoperable DG from the current 72 hours to 14 days. The proposed extension is requested for Division 1 and Division 2 DGs only. The change reflects an 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 LCO. Specifically, the CT for Required Action A.3 and B.4 of "6 days from discovery of failure to meet LCO" would be revised to "17 days from discovery of failure to meet LCO" to accommodate the extended 14-day CT, when either the Division 1 or Division 2 DG is inoperable.

The licensee stated that the proposed CT extension would allow additional flexibility and efficient planning of DG inspection and maintenance activities, and avert an unnecessary unplanned plant shutdown. As stated in its application, "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 than once per operating cycle (24 months). However, the extended CT can be entered as necessary to support corrective maintenance."

In addition, the licensee stated that it would ensure that appropriate restrictions and compensatory measures are established to assure system redundancy, independence, and diversity are maintained, commensurate with the risk associated with the extended CT. The licensee stated in its LAR that these include current TS requirements and Maintenance Rule programmatic requirements as well as administrative controls in accordance with the CRMP. The NRC staff reviewed the plant features and proposed licensee actions and finds the proposed changes to be acceptable for the reasons discussed in the following sections:

3.3.1 Division 3 DG as a Supplemental Source of AC Power Source

In its letter dated March 30, 2010, the licensee stated that the Division 3 DG can be cross-connected to either Division 1 or Division 2 AC buses to provide a supplemental source of power in the event of a LOOP when one DG is in an extended outage and the other DG becomes unavailable or fails to operate, thereby creating a temporary SBO condition. The licensee stated that, since the current SBO coping analysis credits operation of the reactor core isolation cooling (RCIC) system for reactor coolant system inventory control, the HPCS pump is not required, and the associated Division 3 DG can be used as a supplemental AC source. The licensee stated that the cross-connection can be accomplished by on-shift personnel within 2 hours of initiation of an SBO condition. The Division 3 DG has a 2000-hour rating of 2850 kW.

The maximum total load for a LOOP with Unit Trip Condition is 3083 kW for Division 1 and 3009 kW for Division 2 per Updated Safety Analysis Report (USAR) Tables 8.3-1 and 8.3-2. This loading includes two service water (SW) pumps each rated at 442 kW. The licensee stated in the LAR that when the Division 3 DG is cross-connected to either Division 1 or Division 2, only a single SW pump is required to operate to maintain Division 3 DG cooling and Division 1 or Division 2 system loads required for plant shutdown. This provides a net Division 3 DG loading of 2748 kW for Division 1 running loads and 2674 kW for Division 2 running loads. The calculated loading is marginally less than the 2000-hour rating of the Division 3 DG. The licensee provided additional clarification in its letter dated June 1, 2010. Specifically, the licensee clarified that the Division 1 running load is calculated to be 2753 kW for the first 2 hours and 2748 kW during steady state conditions with spent fuel pool cooling (SFP) system loads manually added after 2 hours and one SW pump removed. The corresponding Division 2 loads are 2679 kW for 2 hours and 2674 kW steady state after 2 hours.

The TS surveillance criteria (TS Surveillance Requirement 3.8.1.12a) verifies Division 3 DG loading up to 2730 kW, which is less than the postulated loading discussed above. In its letter dated December 29, 2010 (ML110110165), the licensee stated, "For the Division 3 (HPCS) DG, the 2-hour load range required by Surveillance Requirement 3.8.1.2.a is ≥ 2730 kW and ≤ 2860 kW. The results for the last three surveillance tests (October 2010, July 2008, and October 2006) have been reviewed. For all three of these tests, the average DG load was in excess of 2750 kW, thereby demonstrating that the Division 3 DG is capable of supplying the electrical loads needed for LOOP and SBO events when cross-connected to either the Division 1 or Division 2 emergency bus."

The licensee further stated that the qualification of the Division 3 DG is addressed in General Electric Licensing Topical Report NEDO-10905 (Licensee response dated April 27, 2011, ML11119A137). This topical report establishes the 2000-hour rating of the Division 3 DG as 2850 kW. This rating envelopes the maximum postulated loading. Based on the rating of Division 3 DG, the postulated DG loading for plant shutdown and demonstrated capability of the DG through surveillance testing, the NRC staff concludes that the Division 3 DG is acceptable as a supplemental AC source to bring the plant to a cold shutdown during Division 1 or Division 2 DG maintenance outage.

In response to an NRC staff question regarding the SFP cooling pump load, by letter dated April 27, 2011, the licensee stated that the SFP cooling pump is not needed until approximately 5 hours or longer after inception of the LOOP event, depending on the SFP initial temperature and heat load. The SFP cooling pump thereafter could be operated intermittently to maintain the SFP temperature below the 150 ^{0}F design value and manage Division 3 DG loading below its continuous rating of 2600 kW.

In the LAR, the licensee had proposed the use of the diesel driven fire pump as a supplemental source of cooling water for the Division 3 DG if required to be used as an alternate source of AC power. The NRC staff requested additional information on the support systems required for operation of the fire pump in the event of loss of offsite and onsite AC sources.

In its letter dated April 27, 2011, the licensee provided the details of the Division 3 DG cooling system. The licensee stated that the Division 3 DG has a jacket water heat exchanger system. In the event of a LOOP, while the Division 1 or Division 2 DG is in the extended outage, the Division 3 DG will be aligned as a supplemental source and can power a service water pump to provide the cooling water for the Division 3 DG. The backup source of the Division 3 cooling water would be drawn from the fire protection water supply system. The source of water is Lake Ontario. Since the water is circulated through the DG jacket water heat exchanger and the Division 3 DG is kept warm, when in the standby condition, the jacket water temperature is regulated during engine operation. The licensee further stated that they performed analyses for the modification to install the fire water cooling water supply to the Division 3 DG and determined that the diesel engine driven fire pump has sufficient capacity to provide cooling water to the Division 3 DG while also concurrently supplying fire protection system demands with no adverse consequences. The fire pump has its own battery system, an independent fuel oil system, and a closed loop cooling system. The fire pump is not dependent on Division 1, 2, or 3 systems for continuous operation and is maintained in a state of readiness through routine surveillances.

In the LAR, the licensee stated that a source of backup cooling water supply for the Division 3 DG will be provided from the fire protection water supply section and its associated diesel-driven fire water pump. The licensee stated that the NMP2 and Nine Mile Point Unit 1 (NMP1) fire protection water supply can be cross-tied and either of the NMP2 or NMP1 diesel-driven fire water pumps can perform this function. The licensee further stated that actions needed to establish this backup cooling water supply will be incorporated into plant procedures, including necessary precautions, limitations and details to minimize the human errors and ensure that this feature will only be used for its intended purpose. The NRC staff finds that this approach provides reasonable assurance that the back-up cooling water system for Division 3 DG will be available to ensure safe shutdown capability of the NMP2, and therefore, is acceptable.

The licensee also described that the Division 3 DG support systems, including the fuel oil storage and transfer system, starting air system, lubrication system, combustion air intake, and exhaust system are physically separated from and electrically independent of the auxiliary systems for the Division 1 and Division 2 DGs. The Division 3 fuel oil storage and transfer system has a storage capacity suitable for 7 days of DG operation. The jacket water and lubrication system also have a 7-day capacity. The licensee stated that the makeup fuel oil, jacket water, and lubricating oil can be added as needed for extended operation of the DG beyond 7 days.

The NRC staff concludes that use of the Division 3 DG as a supplemental source of AC power during maintenance of the Division 1 or 2 DG is acceptable based on the following:

1. The Division 3 DG is adequately rated to power shutdown loads in the event of loss of offsite and onsite AC power.

2. Surveillance testing has demonstrated that the Division 3 DG is capable of supplying the electrical loads needed for LOOP and SBO events.

3. Spent fuel cooling can be maintained with intermittent use of the cooling pumps.

4. Division 3 DG cooling system is provided from a service water pump and backed up by the fire protection water supply source which will not degrade the performance capabilities of the DG.

5. The Division 3 DG auxiliary support systems are physically separated and electrically independent from the auxiliary systems for the Division 1 and 2 DGs.

6. The fuel storage capacity and transfer capabilities are adequate to support operation of the Division 3 DG during the extended CT.

7. The lubrication systems are adequate to support operation of the Division 3 DG during the extended CT.

8. The NRC staff has reasonable assurance that the Division 3 DG will be available during the extended CT since routine surveillance testing is required to be conducted in accordance with plant TS.

3.3.2 SBO and DG Availability During Extended Maintenance Period

The NRC staff evaluated the impact of the extended CT on SBO mitigation capability of the plant. NMP2 is classified as a 4-hour SBO duration plant with a 97.5 percent DG target reliability. The licensee stated that the proposed extension of the CT of an inoperable DG will not adversely impact the severe accident risk that was achieved with implementation of the SBO Rule, and will not impact the SBO coping analysis. The assumptions used in the SBO analysis regarding reliability of the DGs will be unaffected by the proposed change, since the licensee will continue to perform preventive maintenance and testing to maintain the DG target reliability.

In its letter dated January 31, 2011, the licensee stated that DG reliability for the current 24-month period through the end of 2010 is above 99.1 percent for all three DGs. Also, in the past 24 months, there have been no failures to start any DGs. Additionally, there have been no Maintenance Rule functional failures for any of the 3 DGs in the last 24 months through the end of 2010.

In response to the NRC staff questions related to Division 3 DG unavailability during a Division 1 or 2 DG outage, the licensee responded that TS 3.8.1 Condition E (two required DGs inoperable) requires the Division 3 DG (or the inoperable Division 1/Division 2 DG) must be restored to Operable within 24 hours to satisfy the TS 3.8.1.E, Required Action and associated CT. Furthermore, the licensee stated that if the 24-hour CT is not met, TS 3.8.1 Condition F would be entered requiring initiation of a plant shutdown. The NRC staff finds that the existing TS Condition E and F specify acceptable Actions during an extended Division 1 or 2 DG outage if the Division 3 DG also becomes inoperable during this time.

Based on the above information, the NRC staff concludes that the 2-hour limit for cross connecting the Division 3 DG to replace Division 1 or Division 2 DGs during extended maintenance period is acceptable as the plant has existing procedures and analyses that support a 4-hour SBO coping capability.

3.3.3 Backup AC Power for Division 1 or Division 2 Battery Chargers

In its LAR, the licensee stated that a 60 kilo Volt Amps (kVA), 480/240 Volt AC portable generator will be available as a temporary back-up source of AC power to one of the Division 1 or Division 2 battery chargers. The licensee states that with this generator providing power to a battery charger, the SBO coping ability can be extended beyond 4 hours as DC power will be available to essential loads. The generator is currently stored on site. The surveillance testing for this generator consists of a monthly no-load test and 6-month test with the generator loaded to 50 percent to 85 percent of its rating for a period of 30 to 45 minutes. The licensee stated that the estimated time to perform the complete procedure to manually connect the generator to the battery charger is 2.5 hours, which is within the 4-hour coping time of the NMP2 SBO analysis. The NRC staff finds this approach acceptable from a defense-in-depth perspective as the licensee should be able to provide additional DC power before the batteries are depleted.

The licensee further stated in letter dated April 27, 2011, that the availability of the portable generator as a temporary source of AC power to the battery chargers associated with the Division 1 and 2 DG, will be controlled as a Regulatory Commitment and will be incorporated in the plant procedures. The NRC staff finds that this approach provides reasonable assurance that adequate DC power will be available to ensure safe shutdown capability of NMP2 in the event of loss of normal onsite AC sources.

3.3.4 Cold Shutdown Capability

In its letters dated March 30, 2010, and December 29, 2010, the licensee stated that in the event of a complete loss of AC power (SBO condition), the preferred method of maintaining stable conditions would be to use the RCIC system to maintain the plant in Mode 3 (Hot Shutdown) until an offsite power source can be restored. It is the NRC staff's position that the restoration of an offsite source or an onsite source may take longer than previously assumed in view of the current limitations of the grid systems. To maintain the defense-in-depth philosophy, the NRC staff requested the licensee to demonstrate that the supplemental AC power has adequate capacity to bring the plant to a cold shutdown condition, if required. In its letter dated December 29, 2010, the licensee outlined two possible approaches for achieving cold shutdown conditions under the postulated loading conditions. The licensee's proposed methods are dependent on the shutdown of the Division that is aligned to the Division 3 DG. By letter dated April 27, 2011, the licensee stated that the net loading for either approach would not exceed the Division 3 DG 2000-hour rating of 2850 kW. The NRC staff finds the postulated loading on Division 3 DG as acceptable for bringing the plant to a cold shutdown, because it is within the capacity of the Division 3 DG.

3.3.5 Defense-in-Depth

Consistent with the discussion in Regulatory Position 2.2.1 of RG 1.177, as part of an LAR proposing a CT change, the licensee should assess whether the change is consistent with the defense-in-depth philosophy. The defense-in-depth philosophy has traditionally been applied in reactor design and operation to provide multiple means to accomplish safety functions and prevent the release of radioactive material.

As discussed in Sections 3.3.1 through 3.3.3 above, the NRC staff concludes that there is reasonable assurance that the Division 3 DG can be used to bring the plant to a cold shutdown as a supplemental AC source, if needed during a Division 1 or Division 2 DG maintenance outage. Therefore, the proposed change is consistent with the defense-in-depth philosophy.

3.3.6 Safety Margins

Consistent with the discussion in Regulatory Position 2.2.2 of RG 1.177, as part of an LAR proposing an AOT (or CT) change, the licensee should assess whether the change is consistent with the principle that sufficient safety margins are maintained. As discussed in the RG, sufficient safety margins are maintained when:

- The proposed TS change is not in conflict with approved Codes and standards relevant to the subject system.
- Safety analysis acceptance criteria in the Updated Final Safety Analysis Report (UFSAR) are met, or proposed revisions provide sufficient margin to account for analysis and data uncertainties (i.e., the proposed TS change does not adversely affect any assumptions or inputs to the safety analysis, or, if such inputs are affected, justification is provided to ensure sufficient safety margins will continue to exist). For TS AOT changes, an assessment should be made of the affect of the UFSAR acceptance criteria assuming the plant is in the AOT (i.e., the subject equipment is inoperable) and there are no additional failures. Such an assessment should result in the identification of all situations in which entry into the proposed AOT could result in failure to meet an intended safety function.

With respect to the first consideration discussed above, the proposed extension of the DG CT remains consistent with the codes and standards applicable to the onsite AC sources, except for RG 1.93 which prescribes a maximum CT of 72 hours for an inoperable onsite or offsite AC source. As stated in its LAR, the licensee would continue to conform to RG 1.93 with the exception that the TS CT for an inoperable DG would 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 SE.

With respect to the second consideration discussed above, the proposed extension of the DG CT would 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. 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. Furthermore, the proposed DG CT extension would have no impact on the availability of the required offsite AC power sources. Therefore, the remaining power sources and safety-related equipment would remain capable of providing power to the equipment required to safely shutdown the plant and mitigate the effects of a DBA.

Based on the above considerations, the NRC staff concludes that the proposed change maintains sufficient safety margins.

3.3.7 Performance Measurement Strategies

As discussed in Regulatory Position 3.2 of RG 1.177, to ensure that extension of a TS AOT does not degrade operational safety over time, the licensee should ensure, as part of its Maintenance Rule program (10 CFR 50.65), that when equipment does not meet its performance criteria, the evaluation required under the Maintenance Rule includes prior related TS changes in its scope. If the licensee concludes that the performance or condition of TS equipment affected by a TS change does not meet established performance criteria, appropriate corrective action should be taken, in accordance with the Maintenance Rule. Such corrective action could include consideration of another TS change to shorten the revised AOT, or imposition of a more restrictive administrative limit, if the licensee determines this is an important factor in reversing the negative trend.

As discussed in Section 3.3 of the Enclosure of the licensee's application dated March 30, 2010:

> 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 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.

The NRC staff finds that the licensee's performance measurement strategies: (1) provide reasonable assurance that appropriate correction actions will be taken if DG performance does not meet its reliability or availability criteria and; (2) are consistent with the requirements in 10 CFR 50.65. As such, the NRC staff concludes that the performance measurement strategies are acceptable.

3.3.8 Compliance with Current Regulations

As discussed in Regulatory Position 2.1 of RG 1.177, the proposed TS change must meet the current regulations.

The NRC staff has reviewed the licensee's proposed amendment. The NRC staff finds that the proposed TS changes provide acceptable remedial actions associated with inoperability of either the Division 1 or Division 2 DG. As such, the proposed change meets the requirements of 10 CFR 50.36(c)(2)(i). As discussed in SE Section 3.3.7, the NRC staff concluded that the proposed change is consistent with the requirements in 10 CFR 50.65. The NRC staff also concludes that the proposed changes do not impact compliance with GDCs 17 and 18.

Based on the above, the NRC staff concludes that the proposed amendment meets current regulations.

3.3.9 Deterministic Evaluation Conclusion

The NRC staff has reviewed the licensee's proposed amendment to TS 3.8.1 to extend the CT for an inoperable Division 1 or Division 2 DG from 72 hours to 14 days. Based on the information provided by the licensee on the cross-connection capability between the safety buses, availability and adequate capacity of the supplemental AC source, and the addition of a portable generator as a backup source to the battery chargers, the NRC staff evaluated the proposed use of the Division 3 DG as an alternate or supplemental power source to supply the safe shutdown loads associated with the inoperable DG (either Division 1 or Division 2) in the event of a LOOP and found it acceptable. The NRC staff's conclusion is based on the following:

- The extended CT will be used for voluntary planned maintenance and inspections, with a DG overhaul performed at a frequency of no more than once per DG per operating cycle (24 months).

- The Division 3 DG will be available and capable of powering either Division 1 or Division 2 loads through the cross-connection within 2 hours of initiation of the SBO condition.

- Appropriate restrictions and compensatory measures will be established with the risk associated with the extended CT. This includes TS requirements and Maintenance Rule programmatic requirements as well as controls in accordance with the CRMP.

- The Division 3 DG is capable of supplying the loads needed to achieve a cold shutdown condition following a postulated SBO condition during extended DG maintenance activities.

Based on the considerations in SE Sections 3.3.1 through 3.3.8, the NRC staff concludes that the proposed amendment is acceptable from a deterministic perspective and the proposed changes to the NMP2 TS provides reasonable assurance of the continued availability of the required electrical power to shut down the reactor and to maintain the reactor in a safe condition after an anticipated operational occurrence. The NRC staff also finds that the regulatory commitments (see section 3.5 of this SE) to implement other restrictions and compensatory measures further ensures the availability of the remaining sources of AC power during the extended CT. The NRC staff recognizes that the extended DG CT would be mainly used for voluntary planned maintenance and inspections, with a DG overhaul performed at a frequency of no more than once per DG operating cycle (24 months). However, the extended CT can be entered, as necessary, to support corrective maintenance activities in a timely manner. Furthermore, the NRC staff concludes that the proposed TS changes are in accordance with 10 CFR 50.36, 10 CFR 50.63, 10 CFR 50.65, and meet the intent of GDCs 17 and 18. Therefore, the NRC staff finds the proposed changes to TS 3.8.1 acceptable.

3.4 Risk-Informed Evaluation

3.4.1 Background

The key information used in the NRC staff's risk-informed evaluation is contained in the licensee's application dated March 30, 2010, as well as supplemental information provided in NMPNS's letters dated June 1, 2010, January 14, 2011, and February 25, 2011.

Using the guidance in SRP Sections 19.2 and Section 16.1, the NRC staff reviewed the proposed amendment using the three-tiered approach discussed in RG 1.177 and the five key principles of risk-informed decision making discussed in RGs 1.174 and RG 1.177. As discussed in these RGs, risk-informed applications should meet the following key principles:

1. The proposed change meets the current regulations, unless it explicitly relates to a requested exemption.

2. The proposed change is consistent with the defense-in-depth philosophy.

3. The proposed change maintains sufficient safety margins.

4. When proposed changes increase CDF or risk, the increase(s) should be small and consistent with the intent of the Commission's Safety Goal Policy Statement (reference, "Safety Goals for the Operation of Nuclear Power Plants; Policy Statement; Correction and Republication," 51 FR 30028, dated August 21, 1986).

5. The impact of the proposed change should be monitored using performance measurement strategies.

As discussed in RG 1.177, some of these key principles can be addressed through traditional (i.e., deterministic) engineering considerations. For the proposed amendment, the deterministic evaluation discussed above in SE Section 3.3 addressed key principles 1, 2, 3, and 5 as summarized below. Key principle 4 is evaluated below in SE Section 3.4.3.

3.4.2 Key Principles 1, 2, 3, and 5

The traditional engineering evaluation addresses key principles 1, 2, 3, and 5 of the NRC staff's philosophy of risk-informed decision making, which concerns compliance with current regulations, evaluation of defense-in-depth, evaluation of safety margins, and performance monitoring strategies.

Key Principle 1 - Current Regulations

As discussed in SE Section 3.3.8, the NRC staff concludes that the proposed change meets current regulations. Therefore, the proposed amendment meets the first key principle of RG 1.177.

Key Principle 2 - Defense-in-Depth

As discussed in SE Section 3.3.5, the NRC staff concludes that the proposed change is consistent with the defense-in-depth philosophy. Therefore, the proposed amendment meets the second key principle of RG 1.177.

Key Principle 3 - Safety Margins

As discussed in SE Section 3.3.6, the NRC staff concludes that the proposed change maintains sufficient safety margins. Therefore, the proposed amendment meets the third key principle of RG 1.177.

Key Principle 5 - Performance Measurement Strategies

RG 1.174 and RG 1.177 establish the need for an implementation and monitoring program to ensure that extensions to TS CTs do not degrade operational safety over time and that no adverse degradation occurs due to unanticipated degradation or common cause mechanisms. An implementation and monitoring program is intended to ensure that the impact of the proposed TS change continues to reflect the reliability and availability of SSCs impacted by the change. RG 1.174 states that monitoring performed in conformance with the Maintenance Rule, 10 CFR 50.65, can be used when the monitoring performed is sufficient for the SSCs affected by the risk-informed application.

As discussed in Section 3.3.7, the NRC staff concludes that the performance measurement strategies associated with the proposed change are acceptable. Therefore, the proposed amendment meets the fifth key principle of RG 1.177.

3.4.3 <u>Key Principle 4 - Risk is Consistent with Commission's Safety Goal Policy Statement</u>

The evaluation presented below addresses the NRC staff's philosophy of risk-informed decision making, that when the proposed changes result in a change in CDF or risk, the increase should be small and consistent with the intent of the Commission's Safety Goal Policy Statement (Key Principle 4).

3.4.3.1 <u>Tier 1: PRA Capability and Insights</u>

The first tier evaluates the impact of the proposed changes on plant operational risk. The Tier 1 NRC staff review involves two aspects: (1) evaluation of the validity of the NMP2 PRA models and their application to the proposed changes, and (2) evaluation of the PRA results and insights based on the licensee's proposed application.

PRA Quality – Internal Events Model

The objective of the PRA quality review is to determine whether the NMP2 PRA used in evaluating the proposed changes is of sufficient scope, level of detail, and technical adequacy for this application. The NRC staff review evaluated the PRA quality information provided by the licensee in their submittal, including industry peer review results and self-assessments performed by the licensee.

The NMP2 PRA model addresses both CDF and LERF for internal and external events at full power. The model has been updated to reflect a proposed power uprate, and a plant modification for backup cooling water to the Division 3 DG which will be implemented prior to implementation of an extended DG outage.

The licensee has processes for configuration control of the NMP2 PRA model to reflect plant modifications and procedure changes. No outstanding changes, not yet incorporated into the PRA model or dispositioned as not relevant to the model, were identified by the licensee except for the power uprate and backup cooling water modifications discussed above.

The NMP2 internal events PRA model was subject to an industry peer review in August 2009 using the American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) PRA Standard ASME/ANS RA-Sa-2009. There were eighteen findings from this review where the internal events model was found not to conform to capability category II of the standard for certain supporting requirements (SRs). The licensee identified and dispositioned these findings for this application, and the NRC staff reviewed their assessment as discussed below:

Finding 1-1 SR DA-C6 (open): Start demands of plant equipment from causes other than surveillance tests were not included in the collection of plant-specific data. The licensee stated that the existing data is slightly conservative, and that estimating demands instead of counting actual demands is not significant. It is conservative to undercount demand data, and there would be a small conservative impact in calculated baseline risk.

Finding 1-2 SR DA-C13 (closed): Unavailability of plant equipment during shutdown conditions was included in contradiction to the standard. The data and model have been revised to not include this unavailability, which resulted in a minor reduction in calculated baseline risk.

Finding 1-9 SR LE-D4 (closed): An optimistic failure probability was applied to low-pressure piping exposed to reactor coolant system pressure. A more realistic failure probability was applied resulting in a minor increase in calculated baseline risk.

Finding 1-11 SR-IFEV-A5 (closed): The internal flooding analysis included events involving water spray, but the frequencies used were the lower flooding frequencies. The licensee reviewed and corrected the internal flooding model, resulting in a minor increase in calculated baseline risk.

Finding 2-5 SR DA-D1 (closed): Bayesian updating of generic data was not performed when there were zero plant-specific failures, which is contrary to the standard. The licensee updated the data for failure rates above 1E-3, and stated that the conservatism of not updating below this probability is minor. The result was a minor decrease in calculated baseline risk.
Finding 2-6 SR DA-D4 (closed): The review identified one instance of inconsistency in the prior and posterior distributions for Bayesian updated data, and a lack of documentation of any evaluation of these distributions for consistency. The licensee performed these evaluations and adjusted the data to account for inconsistencies, resulting in a minor increase in calculated baseline risk.

Finding 2-9 SR SY-B8 (closed): Spatial effects of containment failure on the availability of the service water system was not justified as required in the standard. The licensee identified this as an isolated instance and corrected the documentation to justify that the service water system is not affected by containment failure.

Finding 2-11 SR SY-C3 (closed): Sources of uncertainty were omitted from one system documentation. The licensee identified this as an isolated instance and corrected the documentation to include sources of uncertainty.

Finding 2-16 SR QU-D6 (open): The contributions of structures, systems, and components, as well as operation actions, to initiating event frequencies, is not identified. This is a documentation issue in that it deals with the qualitative evaluation of baseline PRA results.

Finding 3-5 SR MU-F1 (closed): At the time of the peer review, various PRA documentation notebooks were not signed off. The licensee identified completion and issuance of the documents.

Finding 3-6 SR IFSO-B1 (closed): The internal flooding documentation identifies a door held open by a latch, but the design change to install this mechanism has not been implemented in the plant, and in fact the door is blocked open. The documentation was updated to reflect the actual current configuration.

Finding 3-8 SR MU-A1 (closed): The above finding 3-6 is not in a plant database. The licensee identified entry of this item into the applicable database.

Finding 4-7 SR SY-A4 (closed): Several system notebooks do not have a completed system walk down. The licensee identified that these systems are inaccessible, and so walkdowns were not applicable.

Finding 5-2 SR IE-A6 (open): Routine system alignments and their contribution to initiating event frequencies are not included. The licensee identified consideration of routine alignments in the development of average initiating event frequencies, and the revision to include support system fault tree models, as partially addressing this finding. More detailed considerations were identified as having an insignificant impact on results.

Finding 6-1 SR HR-G1 (open): Conservative screening human error probabilities are applied to risk significant functions. The model is conservative, and detailed analysis is expected to have an insignificant impact on the results.

Finding 6-4 SR HR-H2 (closed): The peer review team identified a basic event thought to be an operator action which was not properly evaluated. The licensee identified that the event was in fact not an operator action, and updated the documentation to more clearly define the event.
Finding 6-5 SR AS-C1 (closed): Fault trees associated with the top event of the accident sequence event tree logic are not included in the Accident Sequence Notebook. The licensee identified issuance of the final notebook which includes required documentation.

Finding 6-10 SR IFSN-A14 (closed): Screening of one particular plant area based on presence of flood detection was not consistent with the description of this area in the documentation, which indicates no flood detection for the area. The licensee updated the documentation to identify the appropriate screening criteria.

Based on consideration of the gaps to capability category II of the PRA standard and their disposition for this application, the NRC staff finds that the quality of the NMP2 internal events PRA is sufficient to support the risk evaluation provided by the licensee in support of the proposed license amendment.

PRA Quality – Internal Fires Model

NMP used a PRA analysis to evaluate internal fires. The fire PRA model is an update of the Individual Plant Examination of External Events (IPEEE), which was incorporated directly into the internal events at-power model.

Internal fires were addressed by a combination of the Fire Induced Vulnerability Evaluation (FIVE) methodology and fire PRA techniques described in NUREG/CR-4840. The approach taken for the fire PRA was to perform a scenario-by-scenario analysis of unscreened compartments accounting for the relative location of ignition sources and targets, fire severity, damage thresholds, and fire suppression. Only a small fraction of core damage sequences due to a fire involve a LOOP and a demand for the DGs, and so the contribution of fires to risk associated with the proposed TS change is relatively small.

Since the IPEEE was completed, no internal or external reviews or updates were routinely conducted, and a detailed review was done specifically to support this application to update the fire PRA model. This included, as identified by the licensee: 1) a review of plant modifications to identify any cable or equipment changes, 2) re-evaluation of plant compartments using a lower screening criteria, 3) detailed analysis of unscreened compartments, 4) sensitivity evaluations of human error probabilities, and 5) evaluation of selected relevant spurious operations.

The updated fire model adequately reflects the current plant configuration based on a licensee review of plant modifications which have occurred since the IPEEE was performed. The licensee assessed the IPEEE fire model against the technical elements identified in RG 1.200, Section 1.2.4, and provided the results of this assessment in Attachment 2 of letter dated June 1, 2010. Thirteen gaps, where the licensee identifies a deficiency in its approach compared to the high level requirements found in RG 1.200, were identified and the licensee provided its disposition for this application. The NRC staff reviewed these deficiencies and their disposition, as discussed below.

Equipment Selection: New equipment has been installed in the plant which is not reflected in the fire PRA. The licensee performed a review for Multiple Spurious Operations (MSOs), and a review of modifications since the IPEEE, and did not identify any issues which would affect this application. In addition, six cable modifications were identified potentially impacting modeled components, but were dispositioned as having no impact on this application.

Multiple Spurious Operations: The fire PRA does not fully address MSOs in accordance with current industry guidance. The generic list of MSOs was reviewed for items which could impact AC power. The licensee dispositioned these items as either not applicable or very low likelihood due to the NMP2 specific design, or identified mitigating actions which could be taken in a timely manner.

Instrumentation: The fire PRA does not explicitly account for the availability of plant instrumentation to assure that fire scenarios which rely upon an operator response do not also involve damage to the instrumentation needed to cue the response. The licensee performed a review of important operator actions related to this application and determined that required instrumentation is available and not affected by fire.

Cable Selection: The licensee identified that there may have been changes in cable routing since the IPEEE, but in general, components, junction boxes and panels have not been relocated, and so any new cables would be routed in the same manner through the same fire zones/areas.

Effectiveness of Fire Protection Features and Systems: The carbon dioxide suppression system for the switchgear rooms is now a manual actuation instead of an automatic actuation. This was specifically evaluated for this application by sensitivity studies and determined to be insignificant.

Fire Ignition Frequencies: The most recent available generic ignition data is not applied. The licensee evaluated the changes in the data and determined that the existing IPEEE frequencies are reasonable and in some cases conservative.

Screening Criteria: A compartment CDF screening value of 1E-6 was applied in the IPEEE. This was updated to 1E-7 for screening compartments, and with the application of the current internal events PRA model, the CDF for all compartments was lowered. A lower CDF screening value of 1E-8 was applied to compartments with AC power impacts. Screening for LERF was included in the update to the IPEEE model using a 1E-8 value.

Compartment Screening Contribution to Total Fire CDF: Screened compartments were not added into the total fire CDF. This was judged to be a minor impact on the baseline fire CDF.

Circuit Failure Analysis: A probability of 0.1 was applied for spurious operation without a detailed circuit failure analysis. The licensee stated that this has no impact on the screening analysis conclusions.

Human Reliability for Control Room Scenarios: Only the most risk-significant panel was evaluated in detail, and the licensee stated that exclusion of other less important panels has no impact on this application.

Fire-specific Procedures: Revisions to the procedures since the IPEEE were reviewed to confirm the IPEEE assumptions are still valid.

Undesired Operation Actions due to Spurious Indications: The licensee reviewed only those spurious indications which might be important for this application, and not a general review of all such indications.

Internal Events Operator Actions Assessed for Fire Scenarios: The licensee did not adjust the human error probabilities for fire effects, but addressed this by a sensitivity study which showed the impact was negligible.

Parametric Uncertainties: This has not been performed comprehensively, but application-specific sensitivity analyses have been performed which show that the conclusions for the proposed change are unaffected.

Documentation of Uncertainties and Sensitivities: This is a future documentation issue not impacting the results of the risk analyses.

In addition to these issues, the NRC staff review of the IPEEE identified three specific concerns related to the fire analyses, which the licensee addressed for this application:

Control Room Fire – Optimistic Recovery Probabilities: The licensee identified three probability values applied to control room fire actions. A 1E-3 probability of non-recovery is used for actions which involve long-term inventory control and heat removal where equipment recovery outside the control room is not required. A 1E-2 probability is used for emergency depressurization for low-pressure injection from the control room, or for control room abandonment with successful operation of the reactor core isolation cooling pump. A 1E-1 probability is used for cases involving equipment recovery outside the control room, or for control room abandonment without high-pressure injection. The licensee evaluates these probabilities as being realistic or conservative. The existing guidance on non-suppression probabilities applies 1E-3 as the minimum non-suppression probability, and bases the value on the available time to damage, and not as described by the licensee.

Unrealistic Heat Release Rates: Heat release rates were not an important consideration in the IPEEE control room fire analyses, and recent guidance (NUREG/CR-6850), Appendix L) shows low probability of fire propagation for control room panel fires. The NRC staff notes that this guidance assumes the targets on the main control board are no closer than 0.5 meters for unqualified cables or contiguous for qualified cables; the licensee has not stated that its control board design is consistent with these assumptions in order to justify lower heat release rates.

Unrealistic Detection Times: The control room is continuously manned, and fires are expected to be immediately noticed.

Although the licensee's stated basis for resolution of the above three issues is not well described in its submittals, and may not be completely consistent with existing guidance, the NRC staff would not expect control room fires to be a dominant source of increased risk when a DG is out-of-service, and so additional refinement of the control room fire scenarios would not provide useful insights for this application. The IPEEE results the licensee used are reasonable, considering the overall frequency of main control board fires and the low likelihood of propagation of such fires, as described in NUREG/CR-6850. The licensee has demonstrated consideration of these previously identified issues applying more recent guidance, and its approach is reasonable for this application.

The NRC staff also reviewed other issues relevant to fire PRA. Some inconsistencies with existing guidance were identified in this review.

- The licensee stated that based on the application of "qualified" cables, a damage temperature of 700 ^{0}F was assumed. The qualification status of cables is not a relevant factor in damage temperature, but rather the type of insulation on the cable. Thermoset

- cables use a 625 ^{0}F damage temperature, so the licensee use of 700 ^{0}F is non conservative.
- Heat release rates used by the licensee from the FIVE methodology are slightly non conservative for thermoplastic cables, but slightly conservative for thermoset cables.
- An assumption that only 10 percent of fires in an area can cause damage to vertical trays would typically only apply to transient fires. The fire frequencies should be based on actual combustibles within range of targets as determined by evaluation of the zone of influence, and not adjusted by spatial factors.
- In some cases, credit is taken for the height of targets above the fire source, and it is not clearly identified how the potential for hot gas layers at the ceiling were considered.

The NRC staff considered these issues and whether more refined and updated evaluations would be expected to have a significant impact on the fire PRA results for this application. In its evaluation, the NRC staff also considered sources of conservatism in the existing analysis identified by the licensee, and whether the issue was relevant to the evaluation of those fires determined to have the most impact on the evaluation of the change in risk associated with a DG out-of-service. Based on its review, the NRC staff does not consider these issues, taken collectively and in the context of the application, to be significant to its regulatory decision.

In addition, the NRC staff requested additional information as to the impact of the internal events peer review finding 3-6, which identified a blocked open door between two switchgear rooms, on the risk analysis results for fire. The licensee confirmed its analysis for fires included consideration of the status of this door, and stated that there was insignificant impact.

Based on the licensee evaluation of the IPEEE fire analyses using current high level guidance of RG 1.200, and the disposition of limitations in their existing fire PRA for this application, and on the updated analyses conducted for this specific application, including sensitivity studies, the NRC staff finds that the licensee's scope of analysis and methodology applied is acceptable for this application, and has satisfied the intent of RG 1.177 (Sections 2.3.1, 2.3.2, and 2.3.3), RG 1.174 (Section 2.2.3 and 2.5), and SRP Chapter 19.1, and that the quality of the fire risk analyses and methods applied is sufficient to support the risk evaluation provided by the licensee in support of the proposed license amendment.

PRA Quality – Seismic Event Model

The licensee used a seismic PRA analysis to evaluate seismic events. The seismic PRA model is an update of the IPEEE, which was incorporated directly into the internal events at-power model.

A seismic PRA analysis approach was taken to identify potential seismic vulnerabilities at NMP2, based on the methods of NUREG-1407, and includes the following elements: seismic hazard analysis, seismic fragility assessment, seismic systems analysis, and quantification of seismically-induced CDF, recovery actions under seismic conditions, relay chatter, and containment performance. The contribution of seismic events to the baseline CDF is relatively small, approximately 4 percent (1.5E-7/year).

The IPEEE seismic model was assessed by the licensee against the technical elements identified in RG 1.200, and provided the results of this assessment in Attachment 3 of its letter dated June 1, 2010. Additional clarification as to the scope of these gaps and their impact on the application were provided by the licensee in its January 14, 2011, supplemental submittal. Three gaps, where the licensee identifies a deficiency in its approach compared to the high level requirements found in RG 1.200, were identified, and the licensee provided its disposition for this application. The NRC staff reviewed these deficiencies and their disposition, and are discussed below.

2008 U. S. Geologic Survey (USGS): The seismic hazard (frequencies of events) has not been updated in the NMP2 seismic PRA to reflect the most recent available estimates of these hazards from the USGS. The licensee states that this has no impact on the risk evaluation performed for this application.

Seismic Fragility Analysis: The licensee applied a 0.5g high confidence of low probability of failure as a screening value in the IPEEE, and applied this to develop a plant fragility in its seismic PRA. The use of this 0.5g value is considered conservative, and further evaluations would refine the analysis.

Human Reliability Analysis: The human reliability analysis is conservative for seismic events, and more refined evaluations could be made. The insights gained from fire sensitivity analysis of operator actions taken outside the control room are expected to be similar for seismic events.

There is no contribution of seismically-induced DG failure on the delta-risk estimates for this application. This is due to the assumption of correlation of failures for similar equipment in similar plant locations. That is, a seismic event of sufficient magnitude to fail a DG would fail all DGs, and so the out-of-service status of the DG is not relevant to a seismic evaluation. The dominant contributor from seismic events is a non-recoverable LOOP where the DGs are undamaged. The licensee has included this event in its risk assessment. The NRC staff did not perform detailed review of the seismic PRA quality, since seismic risk other than LOOP is demonstrated as not significant to the regulatory decision.

Other Hazards

The PRA model does not explicitly address other external hazards such as high winds, tornadoes, external floods, or transportation and nearby facility accidents. In the IPEEE, these hazards were screened using the progressive screening methodology described in NUREG-1407. Based on conformance of the NMP2 design with the 1975 SRP criteria, these hazards were determined to not be significant.

The licensee identified the addition of a hydrogen gas storage facility at the NMP site (common for Units 1 and 2). This new facility was evaluated and determined to have negligible impact on CDF and was, therefore, screened from further consideration in the NMP2 PRA model.

PRA Risk Results and Insights

The DGs are modeled in the PRA as impacting mitigation of initiating events, and therefore the DG outage can be directly modeled in the PRA by assuming it is unavailable and unrecoverable (no mitigation credit for the out-of-service DG). The licensee assumed that each DG would incur an additional 14 days of unavailability each 2 years, representing one major maintenance (overhaul) activity. Although additional unavailability due to the extended CT was not assumed, the licensee demonstrated by sensitivity analyses that there is significant margin to the acceptance guidelines to accommodate up to an additional 14 days (28 days total). No other maintenance activities are assumed to occur during the 14-day outage. The ICCDP and ICLERP are based on the entire 14-day duration of the proposed extended CT.

The licensee's risk analysis credits a committed modification to provide backup cooling water to its Division 3 DG from the plant diesel-driven fire pumps.

The licensee's methodology is consistent with the guidance of RG 1.177, Section 2.3.4 and Section 2.4 and is, therefore, acceptable to the NRC staff.

The licensee presented risk results for internal events and for internal fire events. The results are as follows:

Risk Measure	**TOTAL**	**Acceptance Guidance**
ICCDP	2.2E-7 (Division 1 DG) 3.3E-7 (Division 2 DG)	< 5E-7 (RG 1.177)
ICLERP	1.9E-8 (Division 1 DG) 2.4E-8 (Division 2 DG)	< 5E-8 (RG 1.177)
ΔCDF	2.9E-7/year	< 1E-6/year (RG 1.174)
ΔLERF	2.2E-8/year	< 1E-7/ year (RG 1.174)

The calculated risk metrics demonstrate that the acceptance guidelines of RG 1.174 (for very small changes in ΔCDF and ΔLERF) and RG 1.177 (for ICCDP and ICLERP) are met.

Uncertainty and Sensitivity Analysis

The licensee identified assumptions in the PRA models which introduce uncertainty in the results. Most were related to the frequency of LOOP events, including conservative treatment of the 2003 loss of grid event in the northeastern United States, grid stability (addressed by compensatory measures), and seasonal variation in LOOP frequency. Other sources of uncertainty were failure data (data is current through January 2010) and human reliability for actions relevant to the DG (identified as conservatively addressed in the model).

The licensee performed sensitivity studies which confirmed the results being insensitive to seasonal variations in LOOP frequency (based on a conservative assessment consistent with the NRC Information Notice 2006-06, "Loss of Offsite Power and Station Blackout Are More Probable During Summer Period"), changes in assumptions regarding maintenance of other equipment, and increases in the total DG unavailability.

Shutdown Risk

The licensee conservatively does not credit the avoidance of additional risk during plant shutdowns on the assumption that significant DG maintenance would now be performed during plant operations rather than during outage periods.

3.4.3.2 Tier 2: Avoidance of Risk-Significant Plant Configuration

The licensee identified concurrent equipment outages to be avoided during any DG outage exceeding 72 hours, based on evaluation of the risk profile:

- The other two DGs are operable (addressed by TS 3.8.1.1 Condition E)
- No planned maintenance or testing activities on specific offsite power sources (addressed by TS 3.8.1.1 Condition D)
- High Pressure Core Spray (HPCS) system available (addressed by TS 3.8.1.1 Condition B, Required Action B.2, TS 3.5.1, and TS 3.5.3)
- Reactor Core Isolation Cooling (RCIC) system available (addressed by TS 3.5.1 and TS 3.5.3)
- Residual Heat Removal (RHR) and Low Pressure Core Spray (LPCS) systems available (addressed by TS 3.8.1.1 Condition B, Required Action B.2)
- Standby Liquid Control System available (addressed by TS 3.8.1.1 Condition B, Required Action B.2)
- Diesel-driven fire pumps available for backup cooling water to Division 3 DG

For the diesel-driven fire pump, the licensee has made appropriate commitments to procedurally require availability of the backup cooling capability for the Division 3 DG.

Although the existing TS would permit concurrent outages of one DG along with the associated safety train of the above equipment, Required Action B.2 of TS 3.8.1.1 assures that the opposite train is not concurrently unavailable with the DG, which assures that the safety function of these systems is maintained in the event of a LOOP. This TS requirement, combined with the licensee commitment for availability of both trains during extended DG outages, provides an acceptable level of assurance of availability of important equipment to satisfy the Tier 2 requirements.

3.4.3.3 Tier 3: Risk-Informed Configuration Risk Management

The licensee identified its CRMP which ensures that the risk impact of equipment out-of-service is properly evaluated prior to performing any work activity. The program provides for proceduralized risk-informed assessment of equipment unavailability using a blended approach of defense-in-depth and PRA insights, and requires assessment for both planned and unplanned activities, including emergent conditions resulting in configurations not previously assessed. The CRMP, therefore, provides an acceptable process for evaluation of configuration risk during an extended DG outage to satisfy the Tier 3 requirements.

3.4.3.4 Risk Evaluation Conclusion

The risk impact of the proposed 14-day CT for DGs, as reflected in ΔCDF, ΔLERF, ICCDP, and ICLERP, is consistent with the acceptance guidelines specified in RG 1.174, RG 1.177, and NRC staff guidance outlined in Chapter 16.1, "Risk-Informed Decisionmaking: Technical Specifications," of NUREG-0800. The Tier 2 evaluation identified the applicable risk-significant plant equipment outage configurations needing compensatory measures that will be implemented by the licensee during any extended DG outage. The licensee's CRMP satisfies the CRMP requirements of RG 1.177. Therefore, the NRC staff finds that the risk analysis methodology and approach used by the licensee to estimate the risk impacts and manage configuration risk during the extended DG outage are reasonable and of sufficient quality.

Based on the above, the NRC staff finds the proposed changes to extend the DG CT from 72 hours to 14 days to be acceptable.

3.5 Licensee Regulatory Commitments

The licensee made the following regulatory commitments related to the proposed amendment as shown in Attachment 2 of NMPNS letter dated July 25, 2011. This supplemental letter updated the list of regulatory commitments originally provided in Attachment 1 of NMPNS letter dated March 30, 2010, and subsequently revised in Attachment 2 of NMPNS letter dated January 14, 2011. The licensee has identified the following Regulatory Commitments in Attachment 2 of its letter dated July 25, 2011:

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 LAR]

2. Prepare or revise appropriate procedures and training 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: [90 days following NRC approval of the license amendment]

    a. The other two DGs are operable and no planned maintenance or testing activities are scheduled on those two DGs. Should the Division 3 DG become inoperable after entering the extended DG CT, plant shutdown will be initiated if the Division 3 DG cannot be restored to operable status within 24 hours (unless the applicable TS Condition is exited by restoring the Division 1 or Division 2 DG to operable status).

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 operable and no planned maintenance or testing activities are scheduled.

d. The RCIC system is operable 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 NMP 1 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 RHR pumps and the LPCS pump are operable 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 operable 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).

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 safety relief valves (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 (high winds, tornado, or heavy snow/ice) with the potential to degrade or limit offsite power availability are present, or if official weather forecasts are predicting such conditions 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. 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 prestaged within the protected area near the NMP2 control building.

m. Four portable power supplies are available for use to facilitate operation of safety relief valves to maintain RPV pressure control for an extended SBO condition and are verified to be functional.

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitments are provided by the licensee's administrative processes, including its commitment management program. The NRC staff has determined that the commitments do not warrant the creation of regulatory requirements which would require prior NRC approval of subsequent changes. The NRC staff may choose to verify the implementation and maintenance of these commitments in a future inspection or audit.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment. The State official provided comments via e-mail, and the comments were considered in the staff's review of the licensee's application. The comments and the NRC staff's response can be viewed in ADAMS (Accession No. ML113030012).

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (July 13, 2010 (75 FR 39980)). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above that (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.

Principal Contributors: S. Som
A. Howe
G. Waig

Date: October 31, 2011

October 31, 2011

Mr. Kenneth Langdon
Vice President Nine Mile Point
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

SUBJECT: NINE MILE POINT NUCLEAR STATION, UNIT NO. 2 - ISSUANCE OF AMENDMENT REGARDING EXTENSION OF COMPLETION TIME FOR AN INOPERABLE DIVISION 1 OR DIVISION 2 DIESEL GENERATOR (TAC NO. ME3736)

Dear Mr. Langdon:

The Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 138 to Renewed Facility Operating License No. NPF-69 for the Nine Mile Point Nuclear Station, Unit No. 2 (NMP2), in response to your application dated March 30, 2010, as supplemented on June 1, 2010, December 29, 2010, January 14, 2011, February 25, 2011, April 27, 2011, and July 25, 2011. The proposed amendment would modify NMP2 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 from 72 hours to 14 days. The proposed amendment represents a risk-informed licensing change.

A copy of the related Safety Evaluation is enclosed. A Notice of Issuance will be included in the Commission's next regular biweekly *Federal Register* notice.

Sincerely,
/RA/

Richard V. Guzman, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-410

Enclosures:
1. Amendment No. 138 to NPF-69
2. Safety Evaluation

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ADAMS Accession No.: ML112200155
*SE provided by memo. No substantial changes made. **Concurrence via e-mail NRR-106

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