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NINE MILE POINT
NUCLEAR STATION

December 29, 2010

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

ATTENTION: Document Control Desk

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

License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Response to NRC Request for Additional Information (TAC No. ME3736)

REFERENCES:

(a) Letter from S. Belcher (NMPNS) to Document Control Desk (NRC), dated March 30, 2010, License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Technical Specification 3.8.1, AC Sources – Operating

(b) Letter from T. A. Lynch (NMPNS) to Document Control Desk (NRC), dated June 1, 2010, License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Response to NRC Acceptance Review Comments (TAC No. ME3736)

(c) Letter from R. V. Guzman (NRC) to S. L. Belcher (NMPNS), dated November 9, 2010, Request for Additional Information Regarding Nine Mile Point Nuclear Station, Unit No. 2 – Re: Extension of Completion Time for Inoperable Diesel Generator, Electrical Engineering Review (TAC No. ME3736)

Nine Mile Point Nuclear Station, LLC (NMPNS) hereby transmits supplemental information requested by the NRC in support of a previously submitted request for amendment to Nine Mile Point Unit 2 (NMP2) Renewed Operating License NPF-69. The initial request, dated March 30, 2010 (Reference a), as supplemented by Reference (b), proposed to modify Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Time for an inoperable Division 1 or Division 2 diesel generator

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(DG) from 72 hours to 14 days. The supplemental information, provided in the Attachment to this letter, responds to the request for additional information (RAI) documented in the NRC's letter dated November 9, 2010 (Reference c).

Pursuant to 10 CFR 50.91(b)(1), NMPNS has provided a copy of this supplemental information to the appropriate state representative. This letter contains no new regulatory commitments.

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

Very truly yours,

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

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

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Oswego, this 29 day of December, 2010.

WITNESS my Hand and Notarial Seal:

Lisa M. Doran
Notary Public

My Commission Expires:

9/12/2013
Date

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

SB/DEV

Attachment: Nine Mile Point Unit 2 – Response to NRC Request for Additional Information Regarding the Proposed Extension of the Completion Time for an Inoperable Diesel Generator from 72 Hours to 14 Days

cc: Regional Administrator, Region I, NRC
Project Manager, NRC
Resident Inspector, NRC
A. L. Peterson, NYSERDA

ATTACHMENT

NINE MILE POINT UNIT 2

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING THE PROPOSED EXTENSION OF THE

COMPLETION TIME FOR AN INOPERABLE DIESEL GENERATOR

FROM 72 HOURS TO 14 DAYS

Nine Mile Point Nuclear Station, LLC
December 29, 2010

ATTACHMENT

NINE MILE POINT UNIT 2
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING THE PROPOSED EXTENSION OF THE COMPLETION TIME FOR AN INOPERABLE DIESEL GENERATOR FROM 72 HOURS TO 14 DAYS

By letter dated March 30, 2010, as supplemented by letter dated June 1, 2010, Nine Mile Point Nuclear Station, LLC (NMPNS) requested an amendment to the Nine Mile Point Unit 2 (NMP2) Renewed Facility Operating License NPF-69. The proposed amendment would modify Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Time for an inoperable Division 1 or Division 2 diesel generator (DG) from 72 hours to 14 days. This attachment provides supplemental information in response to the request for additional information documented in the NRC's letter dated November 9, 2010. Each individual NRC question is repeated (in italics), followed by the NMPNS response.

RAI-1

In the LAR dated March 30, 2010, the licensee stated that the proposed amendment would modify TS Section 3.8.1, "AC Sources -Operating," to extend the Completion Time (CT) for an inoperable Division 1 or Division 2 DG from 72 hours to 14 days. The detailed description of the proposed change, Section 2.1 in the LAR, has the following statement:

The proposed amendment includes the following revision to TS 3.8.1:

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

From: "6 days from discovery of failure to meet LCO [limiting condition for operation]"
To: "17 days from discovery of failure to meet LCO"

Provide justification for the change related to TS 3.8.1 Condition A.

Response RAI-1

Limiting Condition for Operation (LCO) 3.8.1 requires operability of two sources of AC electrical power: the offsite circuits and the diesel generators (DGs). With this LCO, it could be possible to enter Condition A for an inoperable offsite circuit and before restoring the offsite circuit, a DG could become inoperable (Condition B). With the DG inoperable, the offsite circuit could be restored. Then, before restoring the DG, an offsite circuit could again become inoperable, and so on. Under this scenario, it would be theoretically possible to operate indefinitely without ever meeting the LCO. As described in the current TS Bases, the intent of the third Completion Time (CT) in TS 3.8.1, Condition A, Required Action A.3, is to preclude entry into and exit from the Actions for Conditions A and B for an indefinite period of time without meeting the LCO. The third CT provides a limit on the amount of time that the LCO would not be met for combinations of Conditions A and B. The second CT included in TS 3.8.1, Condition B, Required Action B.4, for an inoperable DG serves the same purpose.

Consistent with the Improved Standard TS (NUREG-1434), these CT limits are determined by adding the maximum CTs from the two Conditions that could extend the CT. These maximum CTs are currently 72 hours (3 days) for the first CT of Required Action A.3 (one inoperable offsite circuit), and 72 hours (3 days) for the first CT of Required Action B.4 (one inoperable DG), yielding a total of 6 days. To reflect the proposed 11-day extension of the CT for an inoperable DG, both the third CT in Required Action A.3

and the third CT in Required Action B.4 are revised to 17 days (3 days for one inoperable offsite circuit plus 14 days for one inoperable DG). These changes to the Condition A and Condition B Required Actions maintain internal consistency and integrity of the TS and are consistent with similar previously approved license amendments (e.g., Donald C. Cook Nuclear Plant – ML052720032; Columbia – ML061000672; Prairie Island Nuclear Generating Plant – ML071310023).

RAI-2

In its letter dated June 1, 2010 (Response to NRC Acceptance Review Comments Item No.7), the licensee provided justification for the extended CT based on a 2-year inspection and 6-year overhaul. Since the licensee has provided justification for the allowed outage time (AOT) extension for 8 days and considering the proposed 2 days to account for uncertainties, the licensee is requested to provide a revised TS for an extension of 10 days (i.e. 8 plus 2 days).

Response RAI-2

As described in the NMPNS letter dated June 1, 2010, the durations of planned 2-year inspections and 6-year overhauls (currently performed during plant outages) has ranged from 5 to 8 days. The NMPNS practice is to schedule planned online maintenance activities so that they are completed within one-half of the TS CT. This practice is acknowledged in Regulatory Guide (RG) 1.177 (Section A.2.3.1). Extending the TS CT to 14 days for an inoperable Division 1 or Division 2 DG to perform planned online maintenance is consistent with this practice. When more than half of the TS CT for a DG outage is used for planned maintenance, there is less time available than desired to resolve unexpected conditions or unknown deficiencies discovered during performance of the maintenance or during subsequent post-maintenance testing. Such emergent conditions can require significant additional time for completion of troubleshooting and repairs. The following are examples of maintenance activities or emergent condition repairs that could potentially require an extended time to complete:

- Diesel fuel oil storage tank inspections
- Heat exchanger inspections, including eddy current testing, with the potential for re-tubing
- Governor or voltage regulator modifications or repairs
- Generator inspections, repairs (e.g., re-winding), or replacement
- Replacement of pistons or cylinder liners
- Bearing replacement

NRC reviewed and approved emergency license amendments and notices of enforcement discretion (NOEDs) relating to repairs of emergent DG conditions requiring an extended completion time (up to or in excess of 14 days) have included the following:

Bearing replacement: Columbia Generating Station – NRC letter dated February 21, 2003, Accession No. ML030520647; Fermi, Unit 2 – NRC letter dated March 29, 2001, Accession No. ML010890156; Clinton Power Station, Unit 1 – NRC letter dated January 18, 2001, Accession No. ML010190071

Piston and bearing replacement: Fermi, Unit 2 – NRC letter dated February 6, 2006, Accession No. ML060360004

Generator repairs: James A. FitzPatrick Nuclear Power Plant – NRC letter dated June 8, 2009, Accession No. ML091550348; South Texas Project, Unit 2 – NRC letter dated December 30, 2003, Accession No. ML033640434

The proposed extension of the TS CT for an inoperable Division 1 or Division 2 DG from 72 hours to 14 days provides a reduction in unnecessary burden, because it:

- Averts unplanned plant shutdowns and minimizes the potential need for enforcement discretion requests;

- Increases the time to perform troubleshooting, repair, and testing of an inoperable DG during Modes 1 through 3, which will enhance the safety and reliability of equipment and personnel; and

- Allows additional time to perform routine maintenance activities on the DGs in Modes 1 through 3, enhancing the ability to focus quality resources on the activity, improve maintenance efficiency, and improve DG availability during plant refueling outages.

The NRC has approved a number of standard license amendments that permanently extended the CT for an inoperable DG to 14 days, based on similar justifications (e.g., Donald C. Cook Nuclear Plant – ML052720032; Columbia – ML061000672; Prairie Island Nuclear Generating Plant – ML071310023; Fermi Unit 2 – ML071830105).

RAI-3

During the period of the extended CT (14 days), the NRC staff expectation is that sufficient defense-in-depth for the onsite power system is provided. Therefore, a supplemental AC (alternating current) source should be provided for the DG under maintenance for the plant to be in cold shutdown. The capacity of the source should be adequate to support a design basis loss-of-offsite power (LOOP) and station blackout (SBO) loads. The licensee has proposed to use the high-pressure core spray (HPCS) DG as an alternate power source for plant shutdown with some plant modifications for operation of HPCS diesel generator. The NRC staff has the following questions related to this application of the HPCS DG.

a. *In LAR Section 3.1.1, item 4, the licensee proposed using the diesel driven fire water pump to provide a source of cooling water to the HPCS DG in the event it is used for plant shutdown upon loss of onsite and offsite power. Provide details on the support systems required for the diesel driven water pump to operate for an extended duration. Specifically, address the capability of the DC control power system and fuel oil requirements.*

Response RAI 3.a

The diesel engine driven fire pump is located in a separate room in the NMP2 screenwell building. The pump takes suction from the service water intake tunnel in the screenwell building, whose source of water is Lake Ontario (an unlimited supply).

The engine start system is self-contained, consisting of two separate starting circuits that provide power to a DC starting motor. The DC power is supplied by two sets of lead-acid storage batteries located within the diesel engine driven fire pump room. An alternator maintains battery voltage during engine operation. A separate battery charger is provided to maintain the batteries in a fully charged condition when the pump is in the normal standby mode. The engine starting circuit is designed such that a loss of AC power will not inhibit automatic starting of the engine. On a loss of AC power, the engine control panel will receive control power from the batteries.

The engine cooling system is a closed loop system cooled by a heat exchanger that is supplied from the discharge side of the diesel engine driven fire pump. Combustion air is drawn from the screenwell building atmosphere, and engine exhaust gases are discharged to the atmosphere via a silencer mounted on the roof of the diesel engine driven fire pump room.

Fuel for the diesel engine is supplied from a diesel fuel oil storage tank located adjacent to the engine. A minimum useable volume of 350 gallons is maintained in the storage tank. This volume of fuel provides for approximately 21 hours of uninterrupted diesel engine operation. Makeup fuel can be readily added to the storage tank, if needed, to extend operation of the diesel engine driven fire pump.

As described in the NMP2 Updated Safety Analysis Report (USAR), Section 9A.3.6.2.6, the diesel engine driven fire pump is maintained in a state of readiness by performance of the following:

- At least once per 31 days, verifying that the fuel tank contains at least 350 gallons of fuel.
- At least once per 31 days, starting the diesel engine driven fire pump from ambient conditions and operating for greater than or equal to 30 minutes on recirculation flow.
- At least once per 92 days, verifying that a sample of diesel fuel from the fuel storage tank is within acceptance limits for viscosity, water, and sediment.
- At least once per 18 months, verifying that the diesel engine driven fire pump starts and maintains the fire suppression water system pressure greater than or equal to 125 psig.
- At least once per 18 months, subjecting the diesel engine to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

As also described in NMP2 USAR Section 9A.3.6.2.6, the diesel engine driven fire pump starting batteries and charger are maintained in a state of readiness by performance of the following:

- At least once per 7 days, verifying that electrolyte level of each cell is above the plates, pilot cell specific gravity is within acceptance limits, and overall battery voltage with the battery on float charge is within acceptance limits.
- At least once per 92 days, verifying that all cell parameters for all battery cells are within acceptance limits, and the difference between the pilot cell with the highest specific gravity compared to the pilot cell with the lowest specific gravity is within a specified amount.

- At least once per 18 months, verifying that the batteries, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration, and that battery and terminal connections are clean, tight, and free of corrosion.

The capability also exists to cross-connect the Nine Mile Point Unit 1 (NMP1) and NMP2 fire water main loops. These loops are interconnected in two places with normally closed valves. The cross-connection can be accomplished by either manually opening a valve located near the NMP2 345 kV switchyard or by opening a motor-operated valve remotely from the NMP1 control room. The NMP1 diesel engine driven fire pump capacity (2500 gpm at a net discharge head of 115 psig) is similar to the NMP2 pump (2500 gpm at a net discharge head of 113 psig) and is maintained in a similar state of readiness, as described in the NMP1 Updated Final Safety Analysis Report (UFSAR), Appendix 10A, Section 2.5.2.3. Fuel for the NMP1 diesel engine driven fire pump is supplied from a fuel day storage tank containing a minimum useable volume of 150 gallons. This volume of fuel provides for approximately 9 hours of uninterrupted diesel engine operation. An underground fuel storage tank containing a minimum useable volume of 1000 gallons is also provided, from which fuel can be transferred to the day tank via either an electric pump or a hand pump. This fuel supply provides approximately 62 hours of additional operating time for the NMP1 diesel engine driven fire pump.

b. *In LAR Section 3.1.1, item 2, the licensee proposed a 60 kVA portable generator as a temporary back-up source of AC power to either Division 1 or Division 2 battery charger, so that the SBO coping can be extended beyond the 4 hours. Provide details on the frequency of the surveillance testing of the portable diesel generator and a time line for aligning this power source to the battery chargers.*

Response RAI 3.b

The 60 kVA, 480/240 VAC portable generator is currently stored on site. Surveillance testing for this portable generator consists of:

- Monthly: No-load operation for a period of 30 to 45 minutes, and
- Every 6 months: Operation at 50% to 85% of rated load for a period of 30 to 45 minutes.

NMP2 has a detailed technical procedure for the connection of a portable 60 kVA, 480/240 VAC generator to a Division 1 or Division 2 battery charger. Once the battery charger is energized from this portable generator, the main divisional DC bus can be powered along with charging power for the associated divisional battery. An outline of the major procedure steps for aligning this power source is provided below.

1. Tools and equipment are assembled. This material is available on site and can be pre-staged ahead of the divisional diesel outage. Major tools and equipment include:

   - 60 kVA portable generator
   - 480 to 575 VAC transformer
   - 700 feet of 4/0 AWG single conductor
   - 4/0 AWG cable lugs

- Tools and material for cable stripping, crimping and connection

2. Open AC feeder breakers to the battery charger and DC output breakers from the charger.

3. Disconnect and isolate normal AC power feed cables that supply the battery charger.

4. Run 4/0 AWG jumper cables from the portable diesel generator to the 480/575 VAC transformer and from the transformer to the AC supply for the battery charger, making necessary connections.

5. Set the battery charger FLOAT adjustment potentiometer to minimum setting (to prevent current limiting condition of the charger).

6. Start the portable generator and energize the temporary transformer.

7. Close in the DC bus breaker from the charger, and then close in charger AC input breaker.

8. Slowly adjust charger output voltage to 135 VDC while maintaining current equal to or less than 300 amps. The portable generator is now supplying the divisional battery charger with AC power. Associated divisional DC loads are energized and the battery is charging.

The estimated time to perform Steps 2 through 8 is 2.5 hours, which is well within the four-hour coping time of the Station Blackout (SBO) analysis.

c. *In the NMP2 Updated Safety Analysis Report (USAR), Table 8.3-5 and Table 8.3-6 provide the maximum total load for LOOP with unit trip condition as 3083 kW for Division 1 (and 3009 kW for Division 2). The licensee has determined the net Division 3 DG load (when cross-connected to Division 1 or Division 2 emergency bus) is reduced to 2748 kW. Provide the basis for removing one service water (SW) pump for a design basis LOOP condition as specified in USAR tables. Also provide details on any procedurally required loads that are manually added to bring the plant to a cold shutdown.*

Response RAI 3.c

Tables 8.3-5 and 8.3-6 of the NMP2 USAR summarize DG loading conditions as a function of time following a loss of offsite power (LOOP) event. These tables are based on the individual loads tabulated in USAR Table 8.3-1 for the Division 1 DG and USAR Table 8.3-2 for the Division 2 DG. As indicated by Note 2 for both Tables 8.3-1 and 8.3-2, following a design basis LOOP event, one service water (SW) pump is automatically started within the first 42 seconds, with a second SW pump assumed to be manually started at greater than or equal to 70 seconds. This assumption maximizes the Division 1 and Division 2 DG loading for the design basis LOOP event.

If a LOOP occurs while the Division 1 or Division 2 DG is in the extended CT and the other DG (Division 2 or Division 1) becomes unavailable or fails to operate, an SBO condition is created. Under the SBO condition, with the Division 3 DG cross-connected to the Division 1 or Division 2 emergency bus, the divisional SW cross-tie valve will close and the non-essential header isolation valves will close,

thereby restricting SW flow to only the safety-related header. Under this alignment, a single operating SW pump provides cooling to the operating Division 3 DG, Division 1 (or 2) safety-related unit coolers, and the Division 1 (or 2) RHR pump seal cooler, with the SW flow rate expected to be less than 2000 gpm. Since SW pump damage could be incurred if the SW pump flow is too low, the existing SBO special operating procedures caution the operators to establish SW flow through the divisional RHR heat exchanger if necessary to maintain SW pump flow greater than 2500 gpm. The service water pumps are each rated at 10,000 gpm; thus, adequate SW flow through the RHR heat exchanger is available to support decay heat removal. It is not necessary or advisable to operate a second SW pump under this condition since low pump flows and potential pump damage could occur, and adequate SW flow is provided by a single operating pump.

As described in NMPNS letter dated March 30, 2010 (Enclosure, Section 3.1.1), and in the Response to RAI 3.b above, the SBO four-hour coping duration, established in accordance with 10 CFR 50.63, can be extended by using a 60 kVA, 480/240 VAC portable generator to supply the Division 1 or Division 2 battery charger. The Division 1 battery charger can then supply the respective divisional Uninterruptable Power Supply (UPS) which provides the Reactor Core Isolation Cooling (RCIC) system control power and instrumentation. The use of the RCIC system to maintain Mode 3 (Hot Shutdown) conditions would be the preferred method for maintaining stable plant conditions until offsite power is restored. The RCIC system is available for reactor water inventory control and reactor pressure control from normal operating pressure to 60 psig, at which time the RCIC steam supply is automatically isolated.

Achieving a cold shutdown condition during SBO conditions is not required by the SBO Rule (10 CFR 50.63). However, the following describes possible approaches for achieving cold shutdown under the postulated SBO conditions.

- Division 1 Energized from Division 3 DG

  In this electrical lineup, the normal method of shutdown cooling is not available. The common suction line to the RHR system contains two containment isolation valves, one powered by Division 1 and the other powered by Division 2. Since Division 1 would be the preferred divisional power source for restoration utilizing the Division 3 DG so that RCIC system control power can be maintained without the use of the 60 kVA portable generator, the inboard containment isolation valve, powered from Division 2, cannot be opened and will not be accessible for manual operation. The RHR pump cannot be aligned from the common shutdown cooling suction path in this condition.

  If the plant must be brought to the cold shutdown condition, an alternate shutdown cooling lineup can be established which utilizes an RHR pump with a suction path from the suppression pool. The return path to the reactor vessel is through the Low Pressure Coolant Injection (LPCI) valve. To achieve this injection path, the reactor pressure vessel must be depressurized using the safety relief valves (SRVs). This opens a return path back to the suppression pool. Cooling necessary to bring the plant to cold shutdown can be achieved using one SW pump with flow through the RHR heat exchanger, and the Division 1 RHR pump. Although an alternate flow path is utilized, the same shutdown cooling heat removal capability is maintained.

- Division 2 Energized from Division 3 DG

  This electrical lineup, when used in conjunction with the 60 kVA portable generator, would provide the most operational flexibility in terms of the ability to achieve cold shutdown. The 60 kVA portable generator would be used to supply the Division 1 battery charger. This lineup allows RCIC system operation to continue while the shutdown cooling lineup is established. The RCIC system and/or SRV operation can be used to reduce reactor pressure to less than the shutdown cooling system isolation interlock.

  The normal mode of shutdown cooling is available in this lineup because power is provided to the inboard containment isolation valve in the common suction line. The outboard containment isolation valve in the common suction line powered from Division 1, which does not have power, can be manually opened providing a suction path for the Division 2 RHR pump. All other valves necessary to perform the system lineup are powered from Division 2. The 60 kVA portable generator supplying the Division 1 battery charger will maintain Division 1 battery voltage so that the Division 1 UPS power remains available. The UPS power provides the logic and instrumentation necessary to satisfy the Division 2 RHR pump suction path and pressure isolation interlocks so that the pump start permissives can be met. Cooling necessary to bring the plant to cold shutdown can be achieved using one SW pump with flow through the RHR heat exchanger, and the Division 2 RHR pump.

d. *The acceptance criteria for HPCS DG loading per TS SR 3.8.1.12(a) is 2730 kW. Provide results from surveillance testing that validate the capability of Division 3 (HPCS) DG to support the higher postulated LOOP loads.*

Response RAI 3.d

The testing performed in accordance with TS Surveillance Requirement (SR) 3.8.1.12 demonstrates that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, 2 hours of which is at a load equivalent to 105% to 110% of the continuous rating of the DG. This SR is performed at a 24-month frequency. For the Division 3 (HPCS) DG, the 2-hour load range required by SR 3.8.1.2.a is $\geq$ 2730 kW and $\leq$ 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.

e. *The USAR Section 8.3.1.1.2 states that the HPCS DG cannot maintain the voltage and frequency within 75 and 90 percent, respectively, during initial loading. For the specific core spray pump load this was acceptable. Provide details on voltage and frequency deviations when the HPCS DG is manually loaded with plant cold shutdown loads, and the capability of running loads to withstand the voltage/frequency perturbations.*

Response RAI 3.e

The HPCS system pump motor is the largest single load powered by the Division 3 emergency bus. With a rating of 3050 hp, it comprises about 94% of the load supplied by the Division 3 DG. As described in NMP2 USAR Section 8.3.1.1.2, due to the large size of the HPCS system pump motor load, the Division 3 DG cannot maintain the Division 3 emergency bus voltage and frequency within 75% of rated voltage and 90% of rated frequency during initial loading. This momentary transient does not have any significant effect on operation of the HPCS system equipment.

As described in NMPNS letter dated March 30, 2010 (Enclosure, Section 3.1.1), as supplemented by NMPNS letter dated June 1, 2010 (Response to Comment 8), cross-connection of the Division 3 DG to either the Division 1 or Division 2 emergency bus to power selected safe shutdown loads is a manual action that would be controlled by the Shift Manager in accordance with the existing NMP2 SBO special operating procedures. In this alignment, the large Division 1 or Division 2 pump motors would each be manually started, as necessary, with sufficient time allowed between motor starts to allow bus voltage and frequency to stabilize. The first pump started would be a service water (SW) pump (560 hp), to provide cooling water to the operating Division 3 DG. Sometime thereafter, a residual heat removal (RHR) system pump (900 hp) would be started. The SW and RHR pump motors are significantly smaller than the HPCS motor load. As such, the magnitude of the frequency and voltage transients when starting these pump motors would be expected to be smaller than the frequency and voltage transient experienced when starting the HPCS pump motor.

To assess performance of the Division 3 DG in the cross-connected configuration, a transient stability analysis of motor starting on the Division 3 DG was performed using eTAP software. The analysis started a SW pump motor and then a RHR pump motor 10 seconds later (to allow voltage and frequency to stabilize). The results indicate that the minimum calculated transient voltage and frequency levels during the SW pump motor start, and during the subsequent RHR pump motor start with the SW pump running, would be within the criteria of 75% of minimum starting voltage and 90% of nominal frequency for individual motors. The maximum calculated transient voltage and frequency levels during the pump motor starts would be within standard 10% allowances for steady state motor operation. The transient duration for these motor starts (on the order of a few seconds) is similar to that of the Division 1 and Division 2 DGs starting similar loads.

The calculated transient voltage and frequency response of the Division 3 DG in the cross-connected configuration was compared with the results obtained from an eTAP transient stability simulation of the sequenced starting of the same loads on the Division 1 and Division 2 DGs. As expected, the largest transient voltage and frequency for Division 1 and Division 2 occurs during starting of the RHR pump motor on either the Division 1 or Division 2 DG, since the RHR pump motor is significantly larger than the SW pump motor. A minimum transient voltage of approximately 88% and a maximum transient voltage of approximately 106% are calculated during starting of a RHR pump motor on a Division 1 or Division 2 DG. The calculated minimum frequency transient response during starting of any emergency load on the Division 1 or Division 2 DGs is approximately 99.5% of nominal frequency.

The eTAP transient stability simulation results are consistent with the results that would be expected based on qualitative assessment. Since the Division 3 DG has a smaller capacity than the Division 1 and Division 2 DGs, there is a larger-magnitude transient voltage and frequency response when starting the

SW and RHR pumps; however, the simulation results demonstrate that both large motors would successfully start with margin. At no time would voltage decrease to less than 75% of nominal or frequency to less than 95% of nominal, consistent with Regulatory Guide 1.9, Revision 2, Regulatory Position C.4 (the current NMP2 licensing basis, as documented in USAR Table 1.8-1). Thus, operation of the permanently connected Division 1 or Division 2 loads would not be adversely affected when powered by the Division 3 DG in the cross-connected configuration.

RAI-4

Since the extended CT is based on implementing compensatory measures and administrative controls in accordance with the configuration risk management program when entering an extended CT, as listed in the regulatory commitments, the TSs should be revised such that if any regulatory commitment, including the operability of the HPCS and its support systems, such as the diesel-powered fire pump motors, is not met during the extended CT period, the CT will revert back to 72 hours from the time of noncompliance. Provide the revised TS(s) as necessary.

Response RAI-4

It is not necessary to establish TS requirements to implement the compensatory measures and configuration risk management controls identified for the proposed DG CT extension amendment.

The requirements for TS limiting conditions for operation (LCOs) are established in 10 CFR 50.36, which states:

> "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 definition of "remedial actions" is described in the Improved Standard Specifications (NUREG-1434), which states:

> "ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times."

The Tier 2 compensatory measures and configuration risk management controls identified for the proposed DG CT extension amendment do not meet the requirements for inclusion in the TS as ACTION statements. These measures and controls are in support of a PRA-based analysis and are pre-requisites for entering the extended DG CT. They are not remedial actions to be taken if the LCO is not met, and they do not have specified completion times.

Regulatory Guide (RG) 1.177 provides the option to address Tier 2 compensatory measures and configuration risk management controls in the TS or in plant procedures. For the Tier 2 compensatory measures and configuration risk management controls identified during the performance of the probabilistic risk assessment (PRA) for the proposed NMP2 license amendment, NMPNS considers it

appropriate to treat these measures and controls as regulatory commitments and to incorporate them into the TS Bases, as shown in Attachment 3 of the March 30, 2010 NMPNS submittal, and into plant procedures. This approach is consistent with the improved TS format, content, and usage rules, which are intended to avoid inclusion of extraneous requirements that are not related to the proper operation and control of plant systems and equipment.

The proposed TS Bases changes (Attachment 3 of the March 30, 2010 NMPNS submittal) require that the Tier 2 compensatory measures and configuration risk management controls be implemented prior to removing a Division 1 or Division 2 DG for planned maintenance utilizing the extended CT (greater than 72 hours and up to 14 days). For an unplanned entry into an extended CT, these measures and controls must be implemented without delay. If one or more of these measures and controls were to be not met while in the extended CT, the condition would be entered into the corrective action program, applicable TS Required Actions would be followed, the risk would be managed in accordance with the NMPNS configuration risk management program (described in Section 3.2.6 of the Enclosure to the March 30, 2010 NMPNS submittal), and the actions to restore the measure(s) or control(s) would be initiated without delay.

Operability requirements applicable to the HPCS system are contained in Technical Specification (TS) 3.5.1 for the HPCS system and in TS 3.8.1 for the Division 3 (HPCS) DG. Both the HPCS system and the HPCS DG are required to be operable in Modes 1, 2, and 3. As specified in TS 3.8.1, if the HPCS DG became inoperable during the time that the Division 1 or Division 2 DG was already inoperable, Required Action E.1 would require that the HPCS DG be restored to operable status within 24 hours. At the end of this 24-hour period, the HPCS system could be declared inoperable in accordance with the Applicability Note for TS 3.8.1, and Condition E could be exited with only one required DG remaining inoperable. However, with a Division 1 or Division 2 DG remaining inoperable and the HPCS system declared inoperable, a redundant required feature failure would exist. Then, in accordance with TS 3.8.1, Required Action B.2, the required features supported by the Division 1 or Division 2 DG would need to be declared inoperable within 4 hours. These required features would include the low pressure emergency core cooling system (ECCS) injection/spray subsystems supported by the Division 1 or Division 2 DG. With both the HPCS system and one division of low pressure ECCS injection/spray subsystems declared inoperable, TS 3.5.1, Required Action H, would require immediate entry into LCO 3.0.3, which would require initiation of a plant shutdown. Thus, with a Division 1 or Division 2 DG already out of service and declared inoperable, the longest time that the HPCS DG could subsequently be inoperable prior to initiating a TS-required plant shutdown would be 28 hours.

The specified safety function of the HPCS system is to spray water into the reactor pressure vessel to adequately cool the core and prevent excessive fuel damage for postulated loss of coolant accidents (LOCAs). The HPCS DG supports this specified HPCS system function by providing an onsite source of AC electrical power to the HPCS system in the event that offsite power is lost concurrent with a LOCA. The capability to cross-connect the HPCS DG to either the Division 1 or Division 2 emergency bus for the purpose of powering selected safe shutdown loads under station blackout (SBO) conditions is not a specified safety function of the HPCS DG but rather is a defense-in-depth feature for a postulated non-design basis event. The NMP1 and NMP2 diesel engine driven fire pumps can provide a source of cooling water to the HPCS DG to support this feature. This capability is a backup to the normal source of HPCS DG cooling provided by operation of a service water pump powered by the Division 1 or Division 2 emergency bus to which the HPCS DG is cross-connected. Thus, consistent with the NMP2 TS

Definition for OPERABLE – OPERABILITY, the NMP1 and NMP2 diesel engine driven fire pumps are not necessary attendant equipment that is required for the HPCS system and the HPCS DG to perform their specified safety functions. On this basis, operability requirements for the diesel engine driven fire pumps do not meet the conditions for inclusion in the TS.

Requirements for maintaining operability of the NMP1 and NMP2 diesel engine driven fire pumps are described in the NMP1 Updated Final Safety Analysis Report (UFSAR), Appendix 10A, Section 2.5.2.3 for the NMP1 pump, and in NMP2 USAR Section 9A.3.6.2.6 for the NMP2 pump. These TS-like fire protection water supply requirements were re-located from the TS to the safety analysis reports in accordance with the guidance in NRC Generic Letter (GL) 88-12, "Removal of Fire Protection Requirements from Technical Specifications." For both NMP1 and NMP2, if the diesel engine driven fire pump is not functional, it must be restored to service within 7 days or an alternate backup pump or water supply must be provided. When either the NMP1 or NMP2 diesel engine driven fire pump is out of service, the typical action taken is to open the cross-connection between the NMP1 and NMP2 fire water main loops (see the Response to RAI 3.a). It is not likely that both diesel engine driven fire pumps would be out of service simultaneously. Changes to fire protection program requirements are controlled in accordance with the provisions of NMP1 License Condition 2.C(7) and NMP2 License Condition 2.F.