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U S Nuclear Regulatory Commission
ATTN: Document Control Desk
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Prairie Island Nuclear Generating Plant Units 1 and 2
Dockets 50-282 and 50-306
License Nos. DPR-42 and DPR-60

Supplement to License Amendment Request (LAR) For Extension Of Technical Specification (TS) 3.8.1, "AC Sources-Operating," Emergency Diesel Generator Completion Time (TAC Nos. MC9001 and MC9002)

By letter dated November 21, 2005, Nuclear Management Company (NMC) submitted an LAR to revise the Emergency Diesel Generator (EDG) Completion Time in TS 3.8.1 Condition B.4 from 7 days to 14 days. This letter supplements the LAR to address NRC requests for additional information (RAIs) regarding this LAR. NMC submits this supplement in accordance with the provisions of 10 CFR 50.90.

Enclosure 1 provides the NRC RAIs and NMC responses. Enclosure 2 provides additional and revised commitments in support of this LAR which supersede the commitments provided in Exhibit D of the original submittal dated November 21, 2005. Enclosure 3 provides detailed information in support of the response to Question 11.

The supplemental information provided in this letter and enclosure does not impact the conclusions of the Determination of No Significant Hazards Consideration and Environmental Assessment presented in the November 21, 2005 submittal.

In accordance with 10 CFR 50.91, NMC is notifying the State of Minnesota of this LAR by transmitting a copy of this letter and enclosures to the designated State Official.

Summary of Commitments

The Enclosure 2 of this letter provides new and revised commitments which supersede the commitments listed in Exhibit D of NMC letter L-PI-05-036, dated November 21, 2005.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on JUN 1 6 2006

Thomas J. Palmisano
Site Vice President, Prairie Island Nuclear Generating Plant Units 1 and 2
Nuclear Management Company, LLC

Enclosures (3)

cc: Administrator, Region III, USNRC
Project Manager, Prairie Island, USNRC
Resident Inspector, Prairie Island, USNRC
State of Minnesota

Enclosure 1

1. In another amendment request, PINGP proposed to revise SR 3.8.1.3 to reduce testing of emergency diesel generators (EDGs) D5 and D6 from the current 5100 kW to at or above 4000 kW because of problems at or near rated load for these EDGs during the monthly testing. Considering the above mentioned request, address how EDGs D5 or D6 can adequately demonstrate the ability to provide back-up power for the Unit 1 inoperable EDG bus during the extended allowed outage time (AOT).

Nuclear Management Company, LLC (NMC) response:

The other amendment request referred to in the question is, "License Amendment Request (LAR) to Reduce Monthly Test Load for Emergency Diesel Generators (EDGs) D5 and D6", dated March 13, 2006. The LAR dated March 13, 2006 did cite EDG test problems above 4000 kW, however, in each of the events cited, the EDG could have performed its required safety function if it had been required to operate with the observed degradation. For each of the events, the Nuclear Management Company (NMC) elected to shut down the engine and investigate prior to reaching the automatic engine trip setpoint. Based on the inspection of removed engine parts and input from engine experts, these engines would have been available to perform their safety function if required.

The purpose of the March 13, 2006 LAR, as stated on page 7 of Exhibit A is that:

> Through this LAR, NMC proposes a better method for managing EDG operating events. Continuing to remove these engines from service for unnecessary repairs increases plant vulnerability instead of decreasing vulnerability. The proposed TS operability testing at or above 4000 kW will allow resolution of EDG issues through the corrective action program and maintenance program in a deliberate planned fashion instead of removing the engines from service for each emergent EDG operating event.

The subject LAR from which these Requests for Additional Information (RAIs) emanate, "License Amendment Request (LAR) For Extension Of Technical Specification (TS) 3.8.1, "AC Sources-Operating," Emergency Diesel Generator Completion Time", dated November 21, 2005, stated the design basis for the EDGs on page 5 of Exhibit A as:

> Each EDG, as a backup to the normal standby AC power supply, is capable of sequentially starting and supplying the power requirements of one of the redundant sets of engineered safety features for its reactor unit. In addition, in the event of a station blackout (SBO) condition, each EDG is capable of sequentially starting and supplying the power requirements of the hot shutdown

> loads for its unit, as well as the essential loads of the blacked out unit, through the use of manual bus tie breakers interconnecting the buses.

Because the LAR dated March 13, 2006 proposes to reduce the test load for the Unit 2 EDGs, the following discussion was provided on pages 7 and 8 of Exhibit A:

> The safety function of the EDGs is to supply power to its associated unit during a design basis accident (DBA) concurrent with a loss of offsite power (LOOP). The PINGP [Prairie Island Nuclear Generating Plant] EDGs also provide the alternate AC source specified in 10 CFR 50.63 during an SBO in the opposite unit.
>
> If the offsite sources should fail, backup power is provided by two EDGs in each unit sized and connected to serve the engineered safety features equipment of the unit. Each EDG is sized to start and carry the engineered safety features load required for the design basis accident (DBA) and concurrent LOOP. For PINGP Unit 2 the "worst case" loads, provided in the PINGP Updated Safety Analysis Report (USAR) Table 8.4.-2, are 3609 kW.
>
> In addition for PINGP, in the event of an SBO condition, each EDG is capable of sequentially starting and supplying the LOOP loads for its unit as well as the essential loads of the blacked out unit. The limiting Unit 2 LOOP loads are given in USAR Table 8.4-4. The maximum predicted LOOP-SBO load on D5 or D6 is approximately 3652 kW.
>
> NMC conservatively chose 4000 kW as the proposed Unit 2 EDGs test loading in SR [Surveillance Requirement] 3.8.1.3 which, as discussed above, is well above the safety function load (3609 kW) and the LOOP-SBO load (3652 kW).

This LAR is not requesting a change to the testing requirements for the Unit 1 EDGs (D1 and D2). The Prairie Island Nuclear Generating Plant (PINGP) Updated Safety Analysis Report (USAR) provides the Unit 1 EDG loads equivalent to the loads for the Unit 2 EDGs provided above. For PINGP Unit 1 the "worst case" loads, provided in USAR Table 8.4.-1, are 2479 kW (0 – 5 minute transient, 2453 kW steady). The limiting Unit 1 LOOP loads are given in USAR Table 8.4-3. The maximum predicted LOOP-SBO load on D1 or D2 is approximately 2624 kW.

These results for both Unit 1 and Unit 2 are summarized in Table 1-1.

Table 1-1
Diesel Generator Capability and Loads

	D1/D2 (Unit 1) (kW)	**D5/D6 (Unit 2) (kW)**
Rating	2750 3000 1000 hour rating 3250 30 min rating	5400 5940 2 hr rating
LOCA[a] + LOOP	2453 steady 2479 0-5 min transient	3609
U1 LOOP + U2 SBO	2624	
U2 LOOP + U1 SBO		3652
Excess SBO	2750-2624 =126	5400-3652 = 1748 4000-3652 = 348
Excess LOOP	U1 LOOP+LOCA load is less than U1 LOOP+U2 SBO load	U2 LOOP+LOCA load is less than U2 LOOP+ U1 SBO load

a- Loss of Coolant Accident (LOCA)

Reducing the SR load from the current 5100 kW to at or above 4000 kW (SR 3.8.1.3) for generators (EDGs) D5 and D6 will still provide assurance that the diesel generators are capable of providing at least 3652 KW during the Unit 1 SBO event. The U1 SBO event is the bounding load event that D5 or D6 may be required to support in the unlikely event of a LOOP and both Unit 1 EDGs fail to accept load.

No physical changes are being made to the U2 EDGs to reduce the excess capacity. The engines are designed to supply 5400 kW and NMC will continue testing the engines between 5100-5300 kW unless conditions prevent an engine from being tested at this power range. The requested change allows the Surveillance Requirement to be reduced to “greater than 4000 kW”. This power level would still assure margin between the required surveillance testing load and the largest postulated load the generators could see during a postulated event.

In conclusion, if a Unit 1 EDG is in an extended Completion Time as proposed in the November 21, 2005 LAR, the Unit 2 EDGs will continue to have adequate capacity and

capability to provide the backup power for the Unit 1 safeguards buses at the TS operability test load of 4000 kW proposed in the March 13, 2006 LAR.

2. Describe the excess capacity of each EDG (that will be used as an alternate power source) beyond its normally available safe shutdown capacity for the loss of offsite power (LOOP) condition. The description should be sufficient to establish that the alternate power source can power the LOOP loads of the inoperable EDG bus.

NMC response:

The EDGs for each unit are the alternate power source for an SBO on the opposite unit. An SBO occurs when the both EDGs for one unit fail to start following a LOOP. The LOOP is assumed to affect both units, thus each EDG may be required to supply power to the LOOP loads for its associated unit plus SBO loads from the opposite unit experiencing an SBO. Plant design features and procedures assure that some LOOP loads are not powered when the event becomes an SBO. Thus, the plant licensing basis does not require the alternate power source to power the LOOP loads of the inoperable EDG bus, but rather SBO as demonstrated below in Tables 2-1 and 2-2. This approach was previously approved by the NRC in the Safety Evaluation for the PINGP submittals in response to 10CFR 50.63, dated September 18, 1990, which stated on pages 4 and 5:

> The NRC's basic position on the use of EDGs as AAC [alternate AC] power sources on the basis of excess capacity is that such excess capacity should not be attained by load shedding in the non-blackout (NBO) unit which results in a degradation of its normally available safe shutdown capability for the loss-of-offsite-power (LOOP) condition. Any actions that would add to the burden of operators that are already in a high stress environment, such as load switching or disablement of information readouts or alarms in the control room, are considered to be a degradation of normal safe shutdown capability for LOOP in the NBO unit. The staff position is therefore that the normal equipment compliment should remain available with adequate EDG capacity for use should it become necessary. The NBO unit should have the capability for hot shutdown/hot standby forced cooling, cooldown and depressurization as required. While additional events are not explicitly being postulated, it is not prudent to diminish the capability of the NBO unit to mitigate problems should they arise. It is not in the interest of safety to reduce the capability to handle various eventualities in one unit for the purpose of meeting the SBO rule in the other unit. Each unit must meet the SBO rule on its own merits without reducing another unit's capability to respond to its own potential problems.

And on page 6 concluded:

> To determine if the existing EDG capacities were consistent with the staff's position (as stated above), the staff referred to the Prairie Island UFSAR

[Updated Final Safety Analysis Report now know as the USAR at PINGP]. Chapter 8, page 8.4-2, stated that each EDG is capable of supplying the power requirement of one complete set of engineered safety features for one reactor unit while providing sufficient power to allow the second unit to be placed in a safe shutdown condition. The review of the loads given in Table 8.4-1 of the UFSAR indicates that each of the existing EDGs has sufficient capacity to supply the SBO loads in the blacked-out and the required LOOP loads in the non-blacked out unit. The licensee's submittal stated that vital loads will be loaded onto the EDG of the non-blacked out unit following a loss of offsite power. Therefore, based on the FSAR [Final Safety Analysis Report] and the licensee's submittal the staff has concluded that there is sufficient capacity and capability in the existing EDGs to comply with the staff's position on crosstied AAC power source capacities. In addition the proposed new EDGs will have a capacity that is almost twice the existing EDG capcity. Based on the above review, the staff assessment of the proposed AAC power source, both existing and proposed (after implementation of the modifications), indicates that it falls into the fully capable AAC power source category cited in section 2.2.1 of this safety evaluation report (SER).

(The modification discussed in the NRC Safety Evaluation was the addition of the Unit 2 Societe Alsacienne de Constructions Mecaniques de Mulhouse (SACM) EDGs which was completed in 1993.)

The LOOP loads on each safeguards train is provided in USAR Tables 8.4-3 and 8.4-4 for Units 1 and 2, respectively. The LOOP loads are assumed to occur in Mode 3 because the Mode 3 loadings bound all other non-power (non-Mode 1) loading and meet the NUMARC criteria for safe shutdown loads. The SBO loads are similar to the LOOP loads except that the SBO unit's EDG auxiliaries would not be operated, nor would the 121 Cooling Water (CL) pump (commonly known as the service water system at other nuclear plants) for a Unit 2 SBO. USAR Tables 8.4-3 and 8.4-4 have been revised to show the SBO loads Units 1 and 2 in Tables 2-1 and 2-2 below. The loading shown in these tables is more conservative than required by NUMARC 87-00 because it includes more than the "essential" loads.

Table 2-1
UNIT 1 SBO LOADS

EQUIPMENT DESCRIPTION	TRAIN A LOAD (kW)	TRAIN B LOAD (kW)
[12] Auxiliary Feedwater (AFW) pump	0	234
11 [12] Component Cooling Water (CC) pump	199	199
11 [12] Battery Charger	39.15	39.15
12 [11 & 13] Charging pumps	91.39	190.98
D1 [D2] EDG Auxiliary Equipment	0	0

EQUIPMENT DESCRIPTION	TRAIN A LOAD (kW)	TRAIN B LOAD (kW)
11 [12] Boric Acid Transfer pump	11.47	11.47
11 & 13 [12 & 14] Containment Recirculation fans	24.74	24.74
11 & 13 [12 & 14] Containment Fan Coil Units (1 Fast, 1 Slow)	74.44	74.44
11 [12] Reactor Vessel Support Cooling fan	19.12	19.12
Pressurizer Heaters Group A (5) [B (5)]	192.00	192.00
121 [122] Air Compressor	79.17	79.17
121 [122] Waste Gas Compressor	19.12	19.12
121 [122] Aux Building Special Vent Exhaust fan & filter	0	0
121 [122] Control Room Water Chiller & Aux Equip	0	0
Equipment & Room coolers and fans	22.2	24.13
Lighting Trans Panel 1rpa8 [1rpb8]	0	0
Inverters (3)	18.78	18.78
Boric Acid Heat Tracing	0	0
Boric Acid Tank Heaters (2)	15.00	15.00
12 [22] Cooling Water Pump Jacket Heaters (2)	0	0
12 [22[Cooling Water Pump Air Start Compressor	0	0
Miscellaneous Equipment	5.83	8.47
Transferable Loads on LOOP Unit	0	0
Estimated Transformer Loss (2% of 480 V Load)	12	14
Estimated Cable Loss (3% of 4160 & 480 V Load)	24	35
TOTAL UNIT 1 LOAD (kW)	**847.41**	**1198.57**

TABLE 2-2
UNIT 2 SBO LOADS

EQUIPMENT DESCRIPTION	TRAIN A LOAD (kW)	TRAIN B LOAD (kW)
21 AFW pump	234	0
21 [22] CC pump	199	199
121 CL pump (Transferable Between Trains)	0	0
21 [22] Battery Charger	39.15	39.15
22 [21 And 23] Charging pump	99.16	198.32
D5 [D6] Supply And Return fans	76.40	76.40
D5 [D6] EDG Aux Equipment (fuel oil pump, Cool/Radiator fans)	0	0

EQUIPMENT DESCRIPTION	TRAIN A LOAD (kW)	TRAIN B LOAD (kW)
21 [22] Boric Acid Transfer pump	11.47	11.47
Boric Acid Heat Tracing	0	0
21 & 23 [22 & 24] Containment Recirculation fans	22.40	22.40
21 & 23 [22 & 24] Containment Fan Coil Units (1 Fast, 1 Slow)	74.44	74.44
Pressurizer Heaters Group A (5) [B (5)]	192.00	192.00
21 [22] Reactor Vessel Support Cooling fan	21.67	21.67
121 [122] Control Room Water Chiller & Aux Equip	0	0
Equipment & Room Coolers And Fans	9.49	9.95
12 [22] Cooling Water Pump Jacket Heaters (2)	0	0
12 [22] Cooling Water Pump Air Start Compressor	0	0
Inverters (3)	18.78	18.78
21 Boric Acid Tank Heater A and [B]	7.5	7.5
Miscellaneous Equipment	5.45	10.63
Transferable Loads on LOOP Unit	0	0
Estimated Transformer Loss (2% of 480 V Load)	12	14
Estimated Cable Loss (3% of 4160 V & 480 V Load)	30	26
TOTAL UNIT 2 LOAD (KW)	**1,052.91**	**921.71**

Following an SBO in one unit, the operators are directed by procedure to provide power to the safeguards buses from the non-SBO unit through bus-ties. The LOOP loads from USAR Table 8.4-3 and 8.4-4 are combined with the SBO loads from Tables 2-1 and 2-2 above for a LOOP on one unit and an SBO on the other unit. The results are shown in Table 2-3 below.

TABLE 2-3
LOOP-SBO EDG loads

Case	Unit 1 LOOP – Unit 2 SBO		Unit 1 SBO – Unit 2 LOOP	
	Train A (kW)	Train B (kW)	Train A (kW)	Train B (kW)
Unit 1 loads	1370	1702	847	1199
Unit 2 loads	1053	922	2602	2453
Total	2423	2624	3449	3652
D1/D2 rating	2750	2750		
D5/D6 rating			5400	5400
D5/D6 LAR dated 3/13/2006 proposed load			4000	4000

Table 2-3 demonstrates that each EDG is capable of supplying the associated unit's LOOP loads and the opposite unit's SBO load within the continuous rating of the EDG. The assumed loads in Mode 3 bound the loads in other non-power modes. Emergency and abnormal operating procedures provide guidance for managing EDG loads within the EDG ratings while transitioning to other modes.

The excess capacity on the Unit 1 EDGs does not change due to this LAR dated November 21, 2005. Utilizing the continuous ratings of 2750 on the Unit1 EDGs, these EDGs will still have 126 kW excess capacity during the highest postulated load condition on the engines.

3. Describe those compensatory measures needed when the alternate AC source becomes inoperable during the extended AOT.

NMC response:

The alternate AC source for the PINGP units is the opposite unit EDGs. As proposed in Enclosure 2 of this letter, NMC has committed to compensatory measures during the extended Completion Time, including a provision that the opposite unit's EDGs will not be removed from service (except for required emergent corrective maintenance or TS required surveillance testing) while an EDG is in an extended Completion Time.

In addition, if one or both of the opposite unit's EDGs involuntarily becomes unable to perform its safety function, the appropriate TS Required Actions would be implemented, and if necessary, additional risk management actions would be implemented. Development of configuration-specific risk management actions is required by regulation per 10CFR50.65 (a)(4). When the risk level associated with emergent equipment unavailability are calculated to be higher than a predefined value, PINGP's configuration risk management program specifically requires implementation of additional risk management actions beyond those associated with normal work controls. The specific risk management actions that are implemented depend upon the overall set of unavailable equipment making up the risk-significant configuration.

4. Clarify the PINGP bus transfer schemes. Specifically address transfers for safety loads.

NMC response:

The fast bus transfer scheme is for the non-safeguards portion of the 4 kV electrical distribution system. The non-safety related buses are Buses 11, 12 13, and 14 for Unit 1 and Buses 21, 22, 23 and 24 for Unit 2. Loads served by these buses are reactor coolant pumps, main feedwater pumps, other non-safeguards motors and 4 kV/480 V stepdown transformers which supply the non 1E 480 V electrical distribution system.

Under normal at power operation the non-safeguard buses are powered from the unit's Main Station Auxiliary Transformer. The fast bus transfer places the non-safeguards buses on the Reserve Station Auxiliary transformer. The fast bus transfer is accomplished upon a lock out of the main generator (G) or the generator transformer (GT). Upon G or GT lock out, the main source breaker to the bus is opened and as long as no undervoltage or underfrequency condition exists on the reserve source, the reserve source breaker goes closed. The reserve breaker closure signal is accomplished by completion of the breaker closing coil circuit through a normally open contact of the G or GT lock out relay.

Each unit has two safeguards buses, Buses 15 and 16 for Unit 1 and Buses 25 and 26 for Unit 2. The normal and alternate sources of power to these buses come from the off-site distribution system (grid). Each bus has an EDG which will provide power to the bus in the event the normal and alternate sources of power are not available.

The selection of what source powers the bus is provided by the associated bus Load Sequencer. The Load Sequencer monitors the voltage of the offsite sources. If a degraded condition is detected on the normal source, the load sequencer will perform a slow transfer of the safeguards bus to the alternate offsite source. This transfer will take place provided the alternate source is not also in a degraded voltage condition. This slow transfer is accomplished automatically by the Load Sequencer in the following steps:

1. All source breakers connect to the bus are tripped;
2. All loads connected to the bus are rejected;
3. The alternate source breaker to the bus is closed; and
4. Restoration of the bus loads is performed in 5 second steps.

If the alternate source is not available, the Load Sequencer will connect the associated EDG to the bus at step 3 of the above sequence when it reaches rated voltage and frequency. The five second step, or permissive, ensures that starting transients have subsided prior to the starting of the next load. The restoration sequence ensures adequate bus voltage and overcurrent protection for the source providing the safeguards bus during load restoration. This restoration sequence provides a slow transfer of the power to the safeguards bus which leads to improved reliability of the safeguards power distribution system.

Motors and loads which are operating prior to the loss of voltage will restart when the Load Sequencer provides the start permissive and the motor was initially started from the control room. The exception to this start is for the Charging pumps which will require manual restart. The safety injection (SI) pump breaker and 480 volt feeder breaker will close upon restoration of power to the associated safeguards bus.

Motors not running prior to the loss of voltage would not start upon restoration of bus voltage, until subsequent manual or automatic action is initiated.

Under safety injection conditions, each safety-related motor will start when the associated start permissive in the sequencer logic occurs, providing the motor has met all auto start requirements.

5. Discuss and provide information on the reliability and availability of offsite power sources relating to the proposed change. The discussion should include duration, cause, date and time of each LOOP (partial or complete) event. Also, provide the current reliability and availability of all EDGs at PINGP.

NMC response:

Offsite power sources to PINGP have been reliable over the more than 30 years of plant operation for each unit. Only two instances of complete loss of offsite power have occurred (both were weather-related – see Table 5-1 below). In both cases, at least a weak source of offsite power did remain available to power some non-safeguards equipment (although no credit for these available offsite sources was taken in the development of the plant-specific LOOP frequency for the LAR risk assessment). In both of these events, all of the onsite EDGs functioned as expected to support safeguards equipment until offsite power was restored to the site.

Table 5-1 below provides details of a review of site records for events other than planned maintenance and testing activities which have impacted the availability of at least one offsite source to at least one safeguards bus. The review included available Licensee Event Reports (LERs) and other reportable event reports, Limiting Condition for Operation (LCO) entry logs, work orders and Corrective Action Program (CAP) documents. The two LOOP events that have occurred are well documented. However, data records for losses of individual offsite sources are not as well-documented, and event data reporting and recordkeeping practices at PINGP have evolved over time. Therefore, an exhaustive records search was not attempted. The table below should constitute most of the offsite source loss events that have occurred since plant startup. The two events described in the preceding paragraph are identified as "complete" LOOP events, while those in which at least one credited offsite source remained available to at least one safeguards 4 kV bus are identified as "partial" LOOP events. Note that the table includes events in which human error played a role in the loss of offsite source(s).

TABLE 5-1
Partial and Complete Losses of Offsite Power at PINGP

Unit	Date	Time	Partial or Complete	Duration	Description/Cause
1	2/28/1975	1400	Partial	momentary	Momentary loss of power to Bus 15 when D1 EDG was removed from the bus following surveillance testing. Voltage restoration operated correctly, but power was

Unit	Date	Time	Partial or Complete	Duration	Description/Cause
					lost long enough to trip several loads off the bus.
2	4/6/1977	829	Partial	31 minutes	Loss of CT-12 supply to Unit 2 safeguards bus (Bus 26, due to personnel error during relay testing) while CT-11 was out of service.
2	4/5/1978	949	Partial	10 minutes	Electrical lockout of 4 kV safeguards Bus 26 due to personnel error during preventive maintenance.
1, 2	9/12/1978	1549	Partial	35 minutes	With both units at 100% power, a lightning strike on the Spring Creek line caused switchyard breaker 6H5 to open. No.10 transformer then tripped on sudden pressure, leaving only 1 offsite power source (CT-11 transformer). The EDGs (D1 and D2 only at the time) started and ran unloaded (no loading was required).
1	11/30/1978	1326	Partial	2 minutes	Electrical lockout of 4 kV safeguards Bus 16 due to personnel error during relay testing.
1, 2	4/16/1979		Partial		During substation switching operations, an error was made which caused failure of No.10 transformer. This left the plant with one source of offsite power.
1,2	6/11/1979	1529	Partial	1.5 hours	With Unit 2 at power and Unit 1 in startup following a refueling outage, substation 345 kV Bus 1 was lost due to a spurious differential current relay lockout. This resulted in the loss of one source of offsite power to the safeguards 4 kV buses (CT-11

Unit	Date	Time	Partial or Complete	Duration	Description/Cause
					transformer).
1, 2	7/15/1980	2030	Complete	1.0 hours	Adverse weather conditions caused faults on the Blue Lake line and both Red Rock lines, which caused loss of 345 kV Bus 1 and CT1 transformer.
1	7/8/1981		Partial	15 minutes	During starting of the 122 Cooling Tower pump, Bus CT-11 transferred to CT-12 on undervoltage. Bus CT-12 subsequently tripped leaving a single source of power available to Unit 1. The CT-11 bus undervoltage relay was subsequently found to have an incorrect setpoint.
1	11/171983	900	Partial	6 hours	While EDG D1 was unavailable due to Appendix R modifications, the bus-tie breaker between Buses 15 and 26 was racked out, leaving Bus 15 with only one source of offsite power (due to personnel error).
2	7/18/1984	934	Partial	1.9 hours	Electrical lockout of 2RY transformer resulted in initiation of voltage restoration schemes on safeguards 4 kV Buses 25 and 26.
1,2	9/18/1984	921	Partial	39 minutes	During protective relay test tripping, a relay technician inadvertently opened a wrong set of trip switches, resulting in loss of Blue Lake line and automatic voltage restoration on all 4 safeguards 4kV buses.

Unit	Date	Time	Partial or Complete	Duration	Description/Cause
1,2	2/6/1985	2105	Partial	2 hours	During restoration of 1R transformer, No.10 transformer locked out due to a faulty ground distance relay, resulting in automatic voltage restoration on Buses 15, 16, and 26.
2	3/24/1986	1039	Partial	2.5 hours	While No.10 Transformer was out of service for maintenance, 2R transformer was isolated from Buses 25 and 26 due to personnel error during substation work. Both EDGs (D1 and D2 only at that time) started (ran unloaded) and automatic voltage restoration occurred as designed.
1	7/27/1987	1541	Partial	1.8 hours	Severe weather (tornado in plant vicinity) caused No. 10 transformer lockout, D1 EDG auto-start.
1	7/31/1987	407	Partial	1.4 hours	No.10 transformer and 1R transformer locked out by relay technician, resulting in loss of 1R source to Unit 1 Buses 15 and 16 and auto-start of both EDGs.
2	9/7/1995	452	Partial	11.9 hours	2RY transformer locked out, leaving Unit 2 with one operable path from the grid.
2	10/13/1995	1036	Partial	1.7 hours	2R transformer source to Buses 25 and 26 inoperable.
1, 2	6/29/1996	1418	Complete	5 hours	With both units at 100% power, high winds caused the loss of three of the four 345 kV transmission lines. Both generating units tripped. The plant's four EDGs (2 for each unit) started and loaded. One 345 kV and one 161 kV transmission line remained energized from offsite power. However, the offsite system voltage at the plant was at or below 330 kV for several hours into the event. The offsite source

Unit	Date	Time	Partial or Complete	Duration	Description/Cause
					became stable five hours after the event began.
2	11/17/1997	1204	Partial	3.2 hours	Sudden pressure lock out of No. 10 transformer - lost one of two offsite paths to Bus 26
1, 2	1/21/1998	1322	Partial	9 hours	Loss of No. 10 transformer. The 1R transformer source to Buses 15 and 16 was taken out of service per procedure in response to the event.
1	1/5/1999	1311	Partial	8.6 hours	Loss of 1R transformer (due to 1M transformer failure).
1	11/4/1999	1136	Partial	1.6 hours	While racking in CT11-1 (during breaker preventive maintenance (PM) work), worker inadvertently bumped relay causing Breaker CT-BT-112 to open, deenergizing Bus16.
1	6/18/2001	204	Partial	16 hours	Grid disturbance due to severe weather caused breaker CT11-1 to open, resulting in a loss of the normal offsite source to Bus 16.
1	8/3/2001	1726	Partial	55.6 hours	1R transformer was deenergized due to Bus 12 fire (Unit 1 forced outage).
2	7/26/2003	2139	Partial	28.2 hours	Ground fault on underground 13.8 kV feeder resulted in loss of power to Bus 26 when substation breakers opened to clear the fault. Voltage restoration operated as designed.
1,2	8/19/2005	719	Partial	3.2 hours	CT1 transformer failed, resulting in CT12 path from grid outside voltage limits and loss of Cooling

Unit	Date	Time	Partial or Complete	Duration	Description/Cause
					Tower source to Buses 16 and 25.
2	8/27/2005	1708	Partial	1.0 hours	During restoration of CT1 transformer, it locked out, resulting in loss of 345 kV Bus 1 and 2R transformer source to Bus 25 and Bus 26

During an April 18, 2006 conference call with the NRC Staff, the second part of this request was clarified by NRC to mean (paraphrasing) "reliability and availability of all EDGs at PINGP since plant startup". However, data is not readily available to fulfill the entire scope of this request. As described above for individual offsite power sources, event data reporting and recordkeeping practices at PINGP have evolved over time. In the specific case of the EDGs, plant operating and maintenance practices have changed over time as well, such that the EDG failure history that exists for early in plant life is not representative of their current reliability and availability. In addition, due to required monthly testing and periodic maintenance on these complex components, the volume of data to be sifted through over such a long time frame is large. Therefore, recovering this information would be prohibitively resource-intensive and provide little additional benefit.

EDG data is readily available in the form of Maintenance Rule and Probabilistic Risk Assessment (PRA) reliability and unavailability data collection records. In lieu of a detailed review of site records for historical diesel generator failures and unavailability periods, NMC proposes to provide more recent data from these sources which should meet the intent of the question.

The reliability and unavailability probability values used in the PINGP PRA model as the basis for the LAR were based on a 10 year operating history (8/1/1994 to 9/1/2004). The unavailability values developed for corrective maintenance (CM) and PM over this period are discussed in the response to Question 13. The reliability values over this period were determined through a review of EDG performance history derived from operator log entries, surveillance test procedure records, LCO log entry records, and maintenance records (work orders) for failures, start demands and run hour demands. As described for EDG unavailability in the response to Question 13, failures and demands occurring on EDGs during outages were included in the data, since these components are able to supply the opposite unit 4 kV buses through bus-tie breakers if necessary. EDG failure history over the PRA data collection period is shown in Table 5-2 below.

TABLE 5-2
EDG Failure History 1994 - 2004

EDG	Date	Work Order Number	Analysis	Failure	Failure Mode
D1	9/6/01	0111255	CR 20017417	D1 ventilation fans did not start in auto.	Run
D1	10/1/97	9711638	CR 19970728	Oil leak on D1 piping	Run
D2	1/23/96	9600538	CR 2010381	CL control valve failed (CV-31506)	Start
D5	3/14/01	0013218	NCR 20004830 and NCR 20010378	D5 Rack Positioner Deviating Display failure (2ZI-5107)	Start
D5	3/13/00	0001311	NCR 20000720	D5 voltage regulator failure	Start
D6	9/14/04		CAP 88522 and MRE 340	D6 radiator fan not running	Run
D6	12/11/01		CR 200186994	Stop jacks on E1 side B actuated on D6	Start
D6	5/26/00	0004237		D6 Fuel Rack LVDT reading full open	Start
D6	10/11/94	9406330	NIR 1193	Fuel oil pump failure	Run

The results of the PRA EDG failure data analysis are shown in Table 5-3 below.

TABLE 5-3
EDG Failure Rate Analysis

Component Failure Mode	Failures	Hour/ Demands	Failure Rate
D1 and D2 FTS[a]	1	238	4.20E-03/demand
D1 and D2 FTR[b]	2	1037	1.93E-03/hour
D5 and D6 FTS	4	251	1.59E-02/demand
D5 and D6 FTR	2	809	2.47E-03/hour

a – Failure to Start

b – Failure to Run

The PINGP Maintenance Rule program also monitors the reliability and availability of the EDGs, in terms of functional failures (MRFFs) and unavailability hours per unit time. Table 5-4 shows the MRFFs that the Maintenance Rule program has recorded against the EDGs that are more recent than the PRA data shown in Table 5-2 above.

TABLE 5-4
Recent EDG-Related Maintenance Rule Functional Failures (MRFFs)

System	SSC/Function	Date of Event	Failure Description
D2	D2 EDG	8/12/2005	CV-31506 (CL Supply for D2 EDG) air supply regulator failed to open. This prevented CV-31506 from opening to cool the diesel generator. The failure was caused by foreign material caught in the solenoid valve for CV-31506.
D5	D5 EDG	4/11/2005	D5 could not complete the monthly slow start surveillance test, because of increasing crankcase pressure, but per Root Cause Evaluation would have met accident performance criteria.

Table 5-5 below shows the current unavailability monitoring results for the EDGs from the Maintenance Rule program:

TABLE 5-5
PINGP Maintenance Rule Program
EDG Unavailability Monitoring - April 2006

Emergency Diesel Generator	Unavailability Performance Criteria (hours/rolling 24 months)	Current Unavailability Level (hours/rolling 24 months)
D1	< 444	337.0
D2	< 444	350.6
D5	< 448	399.5
D6	< 448	348.4

A significant portion of the EDG unavailability is due to regular preventive maintenance tasks, and a majority of this occurs during the 18-month scheduled overhaul activity. These are large, complex maintenance outages with many required subtasks. As stated in the LAR, Section 4.2, a significant portion of online maintenance activities is associated with preparation and return to service activities, such as tagging, fluid system drain-down, fluid system fill and vent, and cylinder block heat-up tasks. Since each of these 18-month PM activities consumes the majority of the current LCO Completion Time, as stated in the LAR, a longer completion time would likely improve maintenance efficiency, and total EDG unavailability may be reduced over the longer term.

6. Consistent with Regulatory Guide 1.177 address what compensatory measure will be taken to ensure that:

A. No maintenance or testing will affect the reliability of the train associated with OPERABLE DG;

B. Discretionary maintenance on the main auxiliary or startup transformers associated with the unit will be controlled;

C. Communication with the system load dispatcher is maintained to ensure that grid load changes during extended AOT are not such that unacceptable voltage would occur following a unit trip; and

D. Elective maintenance will not be performed when grid stress conditions are high such as during extreme summer temperatures and/or high demand.

NMC response:

(6A) The LAR dated November 21, 2005, Exhibit A, Page 10 of 33 stated:

> In the event that an EDG is inoperable in operating Modes 1, 2, 3, and 4, existing TS 3.8.1 Condition B.2 requires that redundant required features that depend on the remaining operable EDG as a source of emergency power be verified to be operable. This provides assurance that a loss of offsite power event will not result in a complete loss of safety function during the period when one of the required EDGs is inoperable.

Condition B.2 allows 4 hours to restore the redundant required feature to operable status or declare the required feature supported by the inoperable EDG inoperable. With two redundant required features inoperable, TS actions may require plant shutdown. Thus, in accordance with current TS 3.8.1 Condition B.2, appropriate TS controls are provided to maintain the reliability of the train associated with the operable EDG while an EDG is in an extended Completion Time.

The commitments provided in the LAR dated November 21, 2005, Exhibit D have been revised and included as Enclosure 2 with this letter. The revised commitments address the remaining parts of this question as follows:

(6B) The second commitment was revised to state, "No elective maintenance will be scheduled in the switchyard that would challenge offsite power availability and no elective maintenance will be scheduled on the main, auxiliary or startup transformers associated with the unit during the proposed extended EDG Completion Time." Thus, in accordance with this revised commitment, discretionary maintenance on the main auxiliary and startup transformers associated with the unit will be controlled.

(6C) The third commitment was revised to state, "The system dispatcher will be contacted once per day to ensure no significant grid perturbations are expected during the extended EDG Completion Time. The system dispatcher will be informed of the EDG status, the power needs of the facility and requested to inform PINGP if conditions change such that unacceptable voltage would occur following a unit trip." Thus, in accordance with this revised commitment, communication with the system load dispatcher is maintained to ensure that grid load changes during an extended Completion Time are not such that unacceptable voltage would occur following a unit trip.

(6D) The first commitment was revised to include the statement, "An extended EDG Completion Time will not be entered to perform elective maintenance when grid stress conditions are high such as during extreme summer temperatures or high demand." Thus, in accordance with this revised commitment, elective maintenance will not be performed when grid stress conditions are high such as during extreme summer temperatures and/or high demand.

7. **Discuss what, if any, contingency plans will be developed to restore the inoperable EDG in the event of unanticipated adverse weather or degraded grid conditions occurring during the AOT which can significantly increase the probability of losing offsite electrical power.**

NMC response:

Generally, entry into an extended Completion Time for an EDG would only be required due to a major overhaul or an equipment failure requiring significant repairs. Restoration of the EDG under these circumstances is unlikely to provide a success path within the time frame associated with unanticipated adverse weather conditions or short-term grid stability issues. For longer-term grid stability issues, further compensatory measures will be provided. Specifically,

- In accordance with the revised commitment contained in the response to Question 6(C), PINGP will be in contact with the transmission system operator during the EDG Completion Time. If PINGP is notified that significant grid perturbations or unacceptable post-trip voltage conditions are expected to occur

during the EDG Completion Time, all planned work except that necessary to restore the inoperable EDG will be discontinued and the EDG will be returned to service as soon as possible.

8. **Provide more detail regarding those measures which assure operating crews are briefed on the EDG work plan and procedural actions regarding: LOOP and SBO, 4kV safeguards bus cross-tie, and Reactor Coolant System bleed and feed. Discuss when any needed briefings will be performed (upon or prior to assuming the watch for the first time, after having scheduled days off while the AOT is in effect, etc.) Discuss whether such a briefing will include both normal and emergency operating procedures.**

NMC response:

The crew turnover briefing content and schedule are reviewed each shift to assure communications are complete. The crew shift turnover briefing includes the shift manager, shift supervisor, control room operators, and the non-licensed operators. The shift turnover briefing includes the description of which EDG is inoperable, the scope of work and the schedule for return to service.

When an EDG is inoperable, the surveillance procedure that verifies operability of the offsite AC paths to the associated unit buses is performed within one hour and every six hours thereafter for the duration of the EDG inoperability. In Enclosure 2, NMC commits to establish procedures that include briefing the operating crews on the LOOP and SBO, 4 kV safeguards bus cross-tie and Reactor Coolant System (RCS) bleed and feed. The surveillance procedure that verifies operability of the offsite AC paths will be revised prior to implementation of this proposed license amendment to include a control room supervisor signoff that the crew has been briefed (within one hour and every six hours thereafter for the duration of the EDG inoperability) on the safeguards bus restoration procedure, the applicable steps of the safeguards bus cross-tie procedures and the applicable steps of the procedure which addresses RCS feed and bleed operations.

9. **Regulatory Guide 1.174 Tier 2 evaluation is intended to establish an early evaluation to identify and preclude potentially high risk plant configurations. The Configuration Risk Management Program (CRMP) can be used to determine such configurations. Tier 3 evaluation is the establishment of a CRMP at the time of the plant equipment outage. The need for this third tier stems from the difficulty of identifying all possible risk- significant configurations under Tier 2 that will be encountered over extended periods of plant operations. Please provide details of the Tier 2 evaluation for the requested emergency diesel generator (EDG) completion time (CT) extension request; i.e., identify for the 14-day outage time any high risk plant configurations that may occur and the compensatory measures/commitments to ensure these configurations do not occur during the extended CT.**

NMC response:

Regulatory Guide 1.177 (RG 1.177) Section 2.3 describes one possible method for performing a Tier 2 evaluation for risk-informed TS Completion Time Extension LARs. This method involves evaluation of combinations of equipment out of service (including the specific equipment for which the LAR is requesting the Completion Time extension) against the Tier 1 Incremental Conditional Core Damage Probability (ICCDP) acceptance guideline (ICCDP < 5E-7). For combinations of equipment unavailability (configurations) found to exceed this risk threshold, a discussion of the controls in place to prevent these configurations from occurring, or the compensatory measures that will be put in place to limit the risk increase, during the Completion Time extension period is required.

An evaluation of potential risk-significant configurations that may be encountered during the extended Completion Time period (should other risk-significant equipment experience unplanned unavailability) was performed. Table 9-1 below shows the trains of equipment unavailability that, in combination with a given EDG, will result in the calculated ICCDP for either unit exceeding the RG 1.177 Tier 1 criteria (5E-7), assuming the configuration exists for the 14 day duration.

TABLE 9-1
Tier 2 Evaluation Results
EDG Unavailability Configurations That Exceed RG 1.177 Tier 1 ICCDP Limit

EDG Assumed Unavailable	**D1 EDG**	**D2 EDG**	**D5 EDG**	**D6 EDG**
Additional Unplanned Unavailability of Any of These Trains of Equipment With EDG Results in Either Unit 1 or Unit 2 ICCDP > 5E-7 (Assumes 14-Day Configuration Duration):	11 AFW pump	11 AFW pump	11 AFW pump	11 AFW pump
	11 safeguards (S/G) Screenhouse Roof Exhaust fan	11 SI pump	21 S/G Screenhouse Roof Exhaust Fan	11 S/G Screenhouse Roof Exhaust fan
	22 SI pump	Bus 15, Sequencer, Auto VR	12 CL Pump & auxiliaries	11 SI pump
	Bus 121	Bus 15/25 Manual VR	22 AFW pump	12 CL pump & auxiliaries
	Bus 16, Sequencer, Auto voltage restoration (VR)	Bus 25, Sequencer, Auto VR	22 CL pump & auxiliaries	22 AFW pump
	Bus 16/26 Manual VR	Bus 26, Sequencer, Auto VR	Bus 121	22 CL Pump & auxiliaries
	Bus 221	D1 EDG & auxiliaries	Bus 15, Sequencer, Auto VR	Bus 15, Sequencer, Auto VR
	Bus 25, Sequencer, Auto VR	D5 EDG & auxiliaries	Bus 16, Sequencer, Auto VR	Bus 15/25 Manual VR
	Bus 26, Sequencer, Auto VR	D6 EDG & auxiliaries	Bus 16/26 Manual VR	Bus 16, Sequencer, Auto VR
	D2 EDG & auxiliaries		Bus 221	Bus 25, Sequencer, Auto VR
	D5 EDG & auxiliaries		Bus 25, Sequencer, Auto VR	CL-43-2 CLOSE (12 CL discharge check)
	D6 EDG & auxiliaries		Bus 26, Sequencer, Auto VR	CL-43-3 CLOSE (121 CL discharge check)
	Motor Control Center (MCC) 1K2		CL-43-2 CLOSE (12 CL discharge check)	D1 EDG & auxiliaries
	MCC 2K2		CL-43-3 CLOSE (121 CL discharge check)	D2 EDG & auxiliaries
			D1 EDG & auxiliaries	D5 EDG & auxiliaries
			D2 EDG & auxiliaries	
			D6 EDG & auxiliaries	
			MCC 1K2	
			MCC 2K2	

The following discussion applies to the results shown in Table 9-1. In each case, the reason why the equipment configuration is risk-significant is described, as well as the available controls and compensatory measures that will prevent voluntary entry into these configurations during the Completion Time extension period:

A. 11 a nd 22 AFW pumps: The availability of these turbine-driven pumps is important when an EDG is unavailable because they can provide auxiliary feedwater flow to the steam generators of their respective unit regardless of the availability of AC power. The 11 AFW pump is also important to Unit 2 risk on a loss of offsite power because, if it is not available, the flow from the 12 AFW pump (motor-driven) is assumed in the PRA model to be required to support the Unit 1 steam generators. (Note that all LOOP initiating events are treated as dual unit initiators in the PINGP PRA model.) The 22 AFW pump is less important to Unit 1 due to the 21 AFW pump dependency on Train A DC power (see response to Question 15).

   Unavailability of the turbine-driven AFW pumps is effectively controlled by existing TS. Plant operation with inoperability of this equipment in combination with an inoperable EDG would not be allowed to continue longer than 72 hours (plant shutdown would then be required).

B. Th e 11 and 21 Safeguards Screenhouse Roof Exhaust fans: These fans are important to Unit 1 and Unit 2 risk with an EDG unavailable because they provide support for all three safeguards CL pumps. At least one fan must be available to support the operation of any of the three safeguards CL pumps. The risk increase is greater for Unit 2 with a Unit 2 EDG unavailable because the Unit 1 EDGs (which would then be required to support Unit 2 loads on a dual-unit LOOP event) require CL for operation (the Unit 2 EDGs are air-cooled).

   Unavailability of the safeguards CL pumps will be controlled by a new commitment (see paragraph D below). The 11 and 21 Safeguards Screenhouse Roof Exhaust fans are required support equipment for operability of each of the safeguards CL pumps.

C. 11 and 22 SI pumps: The availability of these pumps is important for LOOP events which do not transition to SBO (one train of AC power remains available). The SI pump associated with the train of electrical power opposite to the train associated with the EDG that is assumed to be out of service under the Completion Time extension is important, as it is also opposite to the train which supplies power to the motor-driven AFW pump on that unit. For sequences in which the turbine-driven AFW pumps and the opposite unit same train EDG fails to operate, the only remaining source of decay heat removal is through bleed and feed operation using the available SI pump.

   Unavailability of the SI pumps is effectively controlled by existing TS. Plant operation with inoperability of this equipment in combination with an inoperable

EDG would not be allowed to continue longer than 72 hours (plant shutdown would then be required).

D. 12, 121 and 22 CL Pumps: The safeguards CL pumps are risk-significant, particularly to Unit 2, on LOOP events in which one of the Unit 2 EDGs is assumed to be out of service under the Completion Time extension. The Unit 1 EDGs require CL to operate, whereas the Unit 2 EDGs do not. Therefore, with one Unit 2 EDG unavailable when a dual-unit LOOP event occurs, the risk significance of the availability of the safeguards CL pumps is increased relative to Unit 2.

   Unavailability of the safeguards CL pumps is controlled by existing TS. However, one CL pump may be inoperable during normal plant operation, as long as both trains have one operable CL pump. Extended unavailability of the safeguards (and non-safeguards) pumps is monitored by both the site Maintenance Rule program and the Mitigating System Performance Index (MSPI) program, and these programs (required by regulation) will act to limit excessive unavailability over the long term; however, further compensatory measures will be implemented to ensure that inoperability of this equipment in combination with an inoperable Unit 2 EDG (during the Completion Time extension period) will not occur due to elective maintenance. Specifically:

   - Three safeguards CL pumps will be operable when a Unit 2 EDG is in an extended Completion Time, except required emergent corrective maintenance or TS required surveillance testing on safeguards CL pumps or Unit 2 EDGs may be performed if required.

E. CL -43-2 and CL-43-3 (12 and 121 CL pump discharge check valves): The CL system supplies water to plant loads through a ring-header arrangement. Normally, two non-safeguards pumps supply the required flow to the loads on both units. On a dual-unit LOOP event, the PRA model assumes that these pumps lose power, and the safeguards CL pumps (12, 121, and 22 pumps), which are normally in standby status, must automatically start to provide flow. As described in paragraph D above, the safeguards CL pumps are made more risk significant relative to Unit 2 when a Unit 2 EDG is unavailable. Similarly, the open function for their discharge check valves is important. However, the close function is also important for these valves because its failure (for non-running pumps following the LOOP event) would render multiple CL pumps unavailable to supply flow to the ring header.

   Unavailability of the safeguards CL pumps is effectively controlled by existing Technical Specifications and will be further controlled by a new commitment. Check valves CL-43-2 and CL-43-3 are required support equipment for operability of each of the safeguards CL pumps. Plant operation with inoperability of this equipment in combination with an inoperable EDG will be

controlled by the measures described in paragraph D above (for the safeguards CL pumps).

F. 480 V AC Bus 121 and MCC 1K2: These Unit 1, Train B 480 V AC buses are important to Unit 1 risk on LOOP (non-SBO) core damage sequences in which EDG D1 is initially assumed to be unavailable (under the Completion Time extension), and EDG D5 fails to start or run, resulting in a loss of Train A AC power to the site. MCC 1K2, which is powered from Bus 121, supplies power to two of the three Charging pumps (11 and 13) for Unit 1 (the 12 Charging pump is supplied from Train A AC power). In addition, MCC 1K2 supplies power to the CL motor-operated inlet valve associated with the 12 CC Heat Exchanger (12 CCHX). If the 12 CCHX is in standby and the 11 CCHX is in operation, and flow from the 11 CC pump is lost, this valve must open on 12 CC pump start for availability of Train B CC to Unit 1. If Train A AC power is lost to the site, and either 480 V Bus 121 or MCC 1K2 is unavailable, then all Unit 1 Charging pumps and CC pumps (and CCHXs) are unavailable, resulting in loss of Reactor Coolant Pump (RCP) seal cooling and eventually an unrecoverable RCP seal LOCA.

   Unavailability of Bus 121 and MCC 1K2 is effectively controlled by existing Technical Specifications. Plant operation with inoperability of this equipment in combination with an inoperable EDG would not be allowed to continue longer than 8 hours (plant shutdown would then be required).

G. 480 V AC Bus 221 and MCC 2K2: These Unit 2, Train B 480 V AC buses are important to Unit 2 risk on LOOP for the same reasons that Bus 121 and MCC 1K1 are important to Unit 1, as described in paragraph F above.

   Unavailability of Bus 221 and MCC 2K2 is effectively controlled by existing Technical Specifications. Plant operation with inoperability of this equipment in combination with an inoperable EDG would not be allowed to continue longer than 8 hours (plant shutdown would then be required).

H. Either unit, either train safeguards 4 kV AC power buses, including load sequencers, voltage restoration logic and bus-tie breakers: Unavailability of this equipment has the potential to significantly increase the likelihood of SBO, because it removes the possibility for restoration of power to that train of equipment from the opposite unit's offsite power supply or diesel generator supply.

   Unavailability of 4kV safeguards buses is tightly controlled by existing TS and is normally only performed when the associated unit is shut down. Plant operation with inoperability of this equipment in combination with an inoperable EDG would not be allowed to continue longer than 8 hours (plant shutdown would then be required). However, during periods of unit shutdown, existing TS allow one 4 kV safeguards bus to be inoperable and the operable bus to have as few as one

operable offsite source (path). Therefore, further compensatory measures will be implemented to ensure that inoperability of this equipment in combination with an inoperable EDG (during the Completion Time extension period) will not occur due to elective maintenance. Specifically:

- The LCO statement requirements of TS 3.8.1 and TS 3.8.9, for safeguards AC buses, will be met on the opposite unit (regardless of Mode) during the extended EDG Completion Time (required emergent corrective maintenance or TS required surveillance testing on EDGs, offsite paths or safeguards AC buses may be performed).

I. Same unit, opposite train (to the unavailable EDG) EDG and auxiliary equipment: Unavailability of this train of equipment has the potential to significantly increase the likelihood of SBO upon a LOOP to the associated unit.

Unavailability of opposite train EDG when one EDG is already unavailable with the associated unit at power is tightly controlled by existing TS. Plant operation with inoperability of both EDGs would not be allowed to continue longer than 2 hours (plant shutdown would then be required). Unavailability of both EDGs on a unit is only allowed under certain conditions when the unit is shut down.

J. Opposite unit, either train (to the unavailable EDG) EDG and auxiliary equipment: Unavailability of this equipment has the potential to increase the likelihood of SBO upon a LOOP to the associated unit.

Unavailability of opposite unit diesel generators is effectively controlled by existing TS. Operation of either unit with simultaneous inoperability of one EDG on both units is currently not allowed to continue longer than 7 days (plant shutdown would then be required). Under the proposed Completion Time extension to LCO 3.8.1.B, plant operation with this condition would not be allowed to continue longer than 14 days. However, during periods of unit shutdown, existing TS 3.8.2 allows one EDG on the shutdown unit to be inoperable without an associated Completion Time requirement. Therefore, a new compensatory measure will be implemented to ensure that inoperability of this equipment in combination with an inoperable EDG (during the CT Extension period) will not occur due to elective maintenance. Plant operation with inoperability of an opposite unit EDG in combination with an inoperable EDG will be controlled by the measures described in paragraph H above.

K. Switch yard maintenance: errors that may occur during switchyard maintenance have the potential for disruption of single or multiple offsite sources to the plant safeguards 4 kV buses (raising the likelihood of a LOOP to the plant).

Unavailability of offsite sources is effectively controlled by existing TS and will be controlled by a new commitment. Operation of a unit with simultaneous inoperability of one offsite power source and one EDG is currently not allowed to

continue longer than 12 hours (plant shutdown would then be required). Also, as stated in the LAR submittal, plant procedures (to be established) will require that the condition of the grid and the switchyard be evaluated prior to entering the extended EDG Completion Time for elective maintenance, and that elective maintenance not be performed in the switchyard that would challenge offsite power availability during the proposed extended EDG Completion Time.

Unavailability of diesel generators only impacts the mitigation of the loss of offsite power initiating event, by performing the function to restore power to safeguards equipment. Therefore, equipment unavailability configurations providing the highest increase in risk when a diesel generator is unavailable are those that provide or support a redundant and/or diverse means of performing this function. The increase in risk due to concurrent equipment unavailability not on the list above is less significant.

In addition, NMC has implemented unavailability monitoring performance criteria for key risk-significant equipment at PINGP that is shared between the units during shutdown conditions, including the safeguards 4 kV buses themselves (except for Bus 27, which powers only the 121 CL pump and plays no role in restoring power to the opposite unit), under the plant Maintenance Rule program. These criteria include, as a significant part of their basis, the risk-significance of the unavailability of the bus cross-tie capability (to the at-power unit) while the bus is unavailable for maintenance. The current Maintenance Rule unavailability performance criteria associated with the 4 kV AC buses is shown below:

- Buses 15, 25, and 26: < 480 hours per unit outage
- Bus 16: < 360 hours per unit outage

The Bus 16 criterion is more limiting because it supports the 12 AFW pump, which can be cross-tied to Unit 2 and is especially important in the event of a Unit 2 loss of Train A DC power initiating event (see discussion of risk-significant asymmetries between the units in the response to Question 15).

10. In Section 4.4.3 of the license amendment request, Tier 3 credits the capability at Prairie Island Nuclear Generating Plant (PINGP) to perform a configuration dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of maintenance activities that remove equipment from service. Risk is re-assessed if an equipment failure, malfunction or emergent condition produces a plant configuration that has not previously been assessed. Does this configuration dependent assessment credit recovery of the out-of-service equipment? If "yes" describe how the CRMP will correctly assess and manage risk during online performance of EDG maintenance. For example, if the manufacturer's recommended maintenance is performed at power instead of during shutdown, the EDG will not be recoverable in the same amount of time as previously assumed.

NMC response:

The Configuration Risk Management Program (CRMP) in use at PINGP does not credit recovery of out of service equipment.

11. Please provide the detailed Human Reliability Analysis (HRA) for the manual action to cross-tie the 4kV buses between the units. Please provide importance measures for the action (e.g. Fussell-Vesely). How was dependency of this operator action on other operator actions addressed in the model? Describe the operator training content and periodicity for this action. Has the cross-tie capability ever been demonstrated? Please provide a sensitivity of risk if this value is assumed to be an order of magnitude higher.

NMC response:

The operator action to cross tie the 4 kV buses upon loss of all power to a unit (SBO) is specified in an emergency procedure, "Loss of all safeguards AC power". This action is performed entirely from the control room and is not dependent upon successful completion of other operator actions.

Section 8.4.4 of the PINGP USAR states that this action can be performed within 10 minutes of recognition that an SBO event has occurred. Therefore, the required operator actions to perform this task have been tested (successfully) on the simulator in order to validate this 10-minute requirement. The most recent validation was performed in mid-2003. In addition, the lineup to power one unit from the other unit's bus, through the bus-tie breakers, is demonstrated every refueling outage as part of the initial setup for the integrated SI test, although the bus is supplied from offsite power to the opposite unit, rather than from the opposite unit's EDG.

Training on the loss of safeguards power, including simulator-based training, is provided to the Operations staff annually in accordance with the 6-year training plan. As a part of this task, the operators are given a loss of offsite power scenario with varying effects on the safeguards electrical system, including loss of diesel generators and grid disturbances. Over the past four years, the training on this procedure has been more frequent than the annual requirement. In addition, this training is reinforced in simulator exam scenarios and dynamic simulator evaluations.

The basic event in the PRA model used to represent the manual operator action to cross-tie between the 4 kV safeguards buses is 0AMNVLTRXXY. The current failure probability for this event is 4E-03. The importance measures for this event can be found in Table 11-1 below. These measures were taken from the baseline model used to perform the risk metric calculations for the EDG extended Completion Time LAR dated November 21, 2005.

Table 11-1
0AMNVLTRXXY Importance Measures

Unit	Fussel-Vesely	Risk Achievement Worth
1	1.13E-02	3.81
2	1.54E-02	4.82

This event models the manual voltage restoration to a unit experiencing an SBO from the opposite unit not experiencing an SBO. The event involves restoring power to the blacked out unit using the 4 kV safeguards bus-ties between units using the emergency procedure for loss of all safeguards AC power.

The human reliability analysis (HRA) was performed using Version 3.0 of the EPRI HRA calculator. This calculator uses the Caused Based Decision Tree Methodology (CBTM) together with tables from NUREG/CR-1278. The HRA for 0AMNVLTRXXY can be found in Enclosure 3 to this letter.

A sensitivity study was performed for the case where the 4 kV bus-tie failure probability (0AMNVLTRXXY) was increased by an order of magnitude from 4E-3 to 4E-2. The change in core damage frequency (ΔCDF) and the change in large early release frequency (ΔLERF) were recalculated and the results are presented in Tables 11-2 and 11-3 below. In addition, the ICCDP and the incremental conditional large early release probability (ICLERP) were also recalculated for the case where a single EDG is unavailable for PM. The results of this sensitivity study can be found in Table 11-4 below. Tables 11-2 through 11-4 correspond to Tables 2 through 4 in the LAR dated November 21, 2005, Exhibit A. Note that the results for the "Baseline" case shown in the tables include the order of magnitude increase in bus cross-tie operator human error probability (HEP).

Table 11-2
ΔCDF and ΔLERF Results for Increased PM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 criteria
Base Line CDF	1.65E-05	1.89E-05	NA
Base Line LERF	5.74E-07	5.74E-07	NA
New CDF	1.69E-05	1.94E-05	NA
New LERF	5.74E-07	5.74E-07	NA
Delta CDF	3.78E-07	4.18E-07	<1E-6
Delta LERF	< 5E-10	< 5E-10	<1E-7

Table 11-3
ΔCDF and ΔLERF Results for Increased PM and CM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 criteria
Base Line CDF	1.65E-05	1.89E-05	NA
Base Line LERF	5.74E-07	5.74E-07	NA
New CDF	1.71E-05	1.97E-05	NA
New LERF	5.74E-07	5.74E-07	NA
Delta CDF	5.95E-07	7.24E-07	<1E-6
Delta LERF	< 5E-10	< 5E-10	<1E-7

Table 11-4
ICCDP and ICLERP for EDG Inoperable for Preventive Maintenance

Unit	EDG Inoperable	ICCDP	ICLERP
1	D1	4.07E-07	< 5E-10
	D2	4.74E-07	< 5E-10
	D5	1.90E-07	< 5E-10
	D6	1.97E-07	< 5E-10
2	D1	1.90E-07	< 5E-10
	D2	1.34E-07	< 5E-10
	D5	7.59E-07	< 5E-10
	D6	6.81E-07	< 5E-10

The results presented in Tables 11-2 and 11-3 show that the delta CDF and delta LERF results are all less than the RG 1.174 values for annual average CDF and LERF.

The results presented in Table 11-4 show that, in most cases, the calculated ICCDP when an EDG is unavailable for PM are less than the 5E-07 criteria listed in RG 1.177. The two exceptions are the ICCDP values for Unit 2 EDGs D5 and D6. For these two cases only, the results slightly exceed the RG 1.177 limit.

12. At the February 2, 2006, meeting the licensee stated that the PRA model only had the site Loss of Offsite Power (LOOP) initiating event, but not a separate initiating event for a unit LOOP. Depending upon how the initiating event data was developed, this could be conservative or could miss some LOOP risk (non-conservative). Please provide details on how LOOP initiating event (IE) frequency was developed. Were plant-centered LOOP events screened out from the data? If yes, what would be the IE frequency if unit LOOP events had not been screened out? Please provide a sensitivity analysis with unit LOOP events included or otherwise justify that the LOOP risk has been appropriately identified for the EDG CT extension.

NMC response:

The PINGP PRA model is conservative with respect to modeling of the LOOP initiating event. All LOOP initiating events are assumed to be dual-unit events, that is, the LOOP events require diesel generator supplied backup power, and voltage restoration, through either automatic action via the load sequencer logic, or manual action via the bus-tie breakers, to re-power each 4 kV safeguards bus. No credit for the potential availability of an offsite power source to any 4 kV safeguards bus at the site is given in the PRA model.

Although the LOOP event impacts both units simultaneously, due to the plant design, it is highly likely that at least one EDG power supply will be available to supply power to each bus. Each unit has 2 safety-related EDG sets, one dedicated to each safeguards 4 kV bus on that unit, with the ability to cross-tie the train-related EDG to supply power from the opposite unit. In addition, the two EDG sets on Unit 1 are of a different design and manufacturer than are the EDG sets on Unit 2. Also, the Unit 1 EDGs employ a safety-related CL system, while the Unit 2 EDGs are air-cooled.

Therefore, for LOOP events that do not progress to SBO on a given unit (that is, diesel generator power is available to at least one 4 kV safeguards bus on that unit over a full 24-hour mission time), credit is given in the model for the possible restoration of offsite power to certain non-safety-related 4 kV buses to support non-safety-related cooling water (service water) pump operation. This recovery action is significant in sequences involving loss of the diesel powered CL pumps.

A site-specific LOOP initiating event frequency was calculated, based on recent plant experience (years 1994-2003 were included in the calculation used for the EDG Completion Time LAR dated November 21, 2005). However, the PINGP LOOP frequency is also influenced by industry experience for this important initiating event. Industry LOOP and near-LOOP events over the period 1994-2003 (from EPRI TR-1009889) were screened for events applicable to the PINGP site. A review of these results against the information in then draft NUREG/CR-INEEL/EXT-04-02326 was used to confirm applicable LOOP events and categorization of the events. This document was also used in the development of the portion of the overall LOOP frequency attributable to consequential LOOP events (see discussion in response to

Question 19). The overall industry prior mean over the data collection period included plant-centered, grid-related (which included, as separate events applicable to PINGP, the 9 units which lost all offsite power during the August, 2003 Northeastern United States grid failure), weather-related and severe weather-related losses. Although a majority of plant-centered losses involve loss of offsite power to only a single unit (at multiple-unit sites), no attempt to screen out these events based on this criterion was made. The plant-specific frequency was then updated with the industry data using a Bayesian update technique. As expected, the final, updated PINGP LOOP frequency (3.07E-2/yr) was found to be higher than the industry average (2.82E-2/yr), because one LOOP event occurred at the site within that data collection period (a dual-unit LOOP, see Response to Question 5).

13. Please provide a detailed breakdown of the historical and estimated EDG unavailability on all 4 EDGs for preventative and corrective maintenance. How long is periodic EDG maintenance, currently performed while shut down, expected to take? Please justify and explain why 14 days are needed for the CT.

NMC response:

During an April 18, 2006 conference call with the NRC Staff, this request was clarified to mean (paraphrasing) "provide a discussion of the baseline and sensitivity EDG preventive and corrective maintenance unavailability values assumed in the LAR risk calculations (where the sensitivity values are those assumed when under the proposed extended EDG Completion Time)".

<u>Baseline (pre-Completion Time extension) CM and PM unavailability values:</u>

The EDG CM values used in the risk analysis provided in the submittal were based on plant-specific data collection over a recent 10-year period (8/1/1994 to 9/1/2004). All historical work orders and electronic (TS LCO) log entries over that time frame were reviewed, as well as available Maintenance Rule data, for applicable EDG unavailability associated with CM activities. Since the EDGs are credited for providing support to the opposite unit through the train-related bus-tie breaker, applicable maintenance activities occurring during unit outages were also included in the data collection effort, and the total exposure period was considered to be the entire 10-year time frame (unit shutdown time was not subtracted from the data). Due to the significant differences between the Unit 1 (D1and D2) and Unit 2 (D5 and D6) diesel generator design and maintenance schedules, maintenance unavailability data for the two groups of EDG sets were not pooled together. Table 13-1 below, provides a summary of the results of the corrective maintenance data collection and analysis:

Table 13-1
EDG Corrective Maintenance Unavailability Estimates

Component	Hours Unavailable	Exposure Hours	Unavailability Estimate
D1 and D2	1,143.7	175,320	6.52E-03
D5 and D6	2,108.6	175,320	1.20E-02

The EDG PM values used in the risk analysis provided in the submittal were also based on a plant-specific data collection over the same 10-year period (8/1/1994 to 9/1/2004). The value includes not only preventive maintenance, but also all unavailability associated with surveillance and other testing performed on the EDGs. This is significant for PINGP Unit 1 EDGs, which have mechanical governors. Unavailability time is conservatively counted whenever the speed droop governor setting on the EDG set is adjusted away from normal during load testing (including during the TS required monthly test). The D5 and D6 diesel generators have an electronic governor system and are not subject to this type of unavailability during routine testing.

The majority of the unavailability associated with preventive maintenance comes from the regular overhaul activities performed on an 18-month interval. All historical work orders and electronic (TS LCO) log entries over that time frame were reviewed, as well as available Maintenance Rule data, for applicable EDG unavailability associated with PM activities. As described above, the total exposure period for EDG maintenance was considered to be the entire 10-year time frame (unit shutdown time was not subtracted from the data), and data for the two groups of EDG sets were not pooled together. Table 13-2, below, provides a summary of the results of the preventive maintenance data collection and analysis:

Table 13-2
EDG Preventive Maintenance Unavailability Estimates

Component	Hours Unavailable	Exposure Hours	Unavailability Estimate
D1 and D2	2,584.9	175,320	1.47E-02
D5 and D6	2,159.5	175,320	1.23E-02

<u>Sensitivity (post-Completion Time extension) values:</u>

The risk analysis presented in the November 21, 2005 LAR submittal included calculation of both delta CDF and delta LERF, as well as ICCDP and the ICLERP. The sensitivity values for CM and PM were included in both calculations.

The delta CDF and delta LERF calculations compare the baseline CDF and LERF values (metrics calculated assuming baseline, pre-Completion Time extension values) against new metrics calculated assuming an increase in the PM unavailability term for each EDG based on having the ability to utilize the proposed Completion Time extension. Also, although an increase in the unavailability due to corrective maintenance is not expected under the Completion Time extension, an assumed increase in the CM unavailability term was also included as a sensitivity study.

For the delta CDF and delta LERF calculations, it was assumed that the existing PM unavailability will increase as a result of performing the major overhauls on line, to 9.9 days per year, to account for a 14 day major overhaul once per refueling cycle for each EDG. The assumption was made that, if the 14 day Completion Time is used for PM, the normal PM will not be performed again during the fuel cycle. The refueling cycle length was assumed to be 18 months, with an assumed total planned and unplanned outage duration of 30 days, which yields a cycle length of 518 days.

$$PM\ Term\ Value = \left(\frac{14\ days}{518}\right) = 2.70E-02\ yr\ or\ 9.9\ days/year$$

In the PRA sensitivity analysis, the existing PM unavailability terms for EDGs D1, D2, D5 and D6 were increased to 2.70E-02 to model the increased PM frequency. The resulting values are shown in Table 13-3 below.

Table 13-3
Increased PM Terms

Diesel Generator	Original PM Value	Revised PM Value
D1	1.47E-02	2.70E-02
D2	1.47E-02	2.70E-02
D5	1.23E-02	2.70E-02
D6	1.23E-02	2.70E-02

As described in the original LAR dated November 21, 2005, as a sensitivity study, consideration was given to the potential for an increase in the CM term as well. For this sensitivity, the existing CM term was scaled by the ratio of the proposed and current Completion Times or 14/7 (a factor of two). The resulting values are shown in Table 13-4 below.

Table 13-4
Increased CM Terms

Diesel Generator	Original CM Value	Revised CM Value
D1	6.52E-03	1.30E-02
D2	6.52E-03	1.30E-02
D5	1.20E-02	2.40E-02
D6	1.20E-02	2.40E-02

Expected duration of EDG maintenance

The 18-month PM activities for each of the four EDGs requires approximately 5 days to perform and is normally performed while the unit is on-line. Performance of the Unit 2 EDG PM in conjunction with replacement of 4 pistons and cylinder lines requires approximately 6.5 days and has also been performed while the unit is on-line. Major EDG overhaul such as replacement of Unit 1 EDG cylinder liners requires approximately 10 days to perform or total engine rebuild of the Unit 2 EDGs requires approximately 12 days. With the current PINGP TS limitations, the major overhaul activities must be performed during a unit shutdown.

Explanation and justification for extending EDG Completion Time

Explanation and justification for extending the EDG Completion Time from 7 days to 14 days is provided in the LAR submitted November 21, 2005, Exhibit A, Sections 3.5 and 4.2.

Section 3.5 states in part:

> Routine EDG preventive maintenance activities typically require 4 to 6 days to perform which often gives rise to NMC and NRC concern that the TS Completion Time of 7 days will not be met. The preventive maintenance completion date can be extended by emergent maintenance issues which challenge the 7 day Completion Time.
>
> Special EDG maintenance overhaul activities, such as periodic cylinder liner replacement, require more than 7 days to perform. Thus, these activities must be scheduled to be performed during a plant refueling outage to avoid plant shutdown due to the current 7 day Completion Time. Extending the EDG Completion Time to 14 days will allow more on-line special overhauls which will improve EDG availability during plant refueling outages and should reduce the risk due to EDG unavailability occurring concurrently with other activities and equipment outages during a refueling outage. This change provides flexibility to improve the quality of EDG maintenance activities and the quality of outage

activities by reducing the competing resource demands.

Section 4.2 states in part:

> The extended TS Completion Time for EDGs improves effectiveness of the allowed maintenance period. A significant portion of on-line maintenance activities is associated with preparation and return to service activities, such as, tagging, fluid system drain down, fluid system fill and vent, and cylinder block heat-up. The duration of these activities is relatively constant. Longer Required Action Completion Time durations allows more maintenance to be accomplished during a given on-line maintenance period and therefore would improve maintenance efficiency. Thus the total EDG unavailability may be reduced with this proposed change.
>
> This change will allow some maintenance activities to be performed on-line which would otherwise require performance during a refueling outage. On-line preventive maintenance and scheduled overhauls provide the flexibility to focus more quality resources on any required or elective diesel generator maintenance. For example, during refueling outages, resources are required to support many systems; during on-line maintenance, plant resources can be more focused on the diesel generator overhaul.
>
> Performance of more diesel generator maintenance on-line will improve EDG availability during plant refueling outages. Performing more EDG overhaul activities on-line should reduce the risk and synergistic effects on risk due to EDG unavailability occurring concurrently with other activities and equipment outages during a refueling outage.

In summary, NMC anticipates that extending the EDG Completion Time will reduce NMC and NRC concerns that the TS Completion Time will not be met, improve the quality of EDG maintenance and plant outage activities, reduce EDG unavailability, and reduce EDG unavailability during plant outages.

14. How was common cause failure treated when calculating risk for corrective maintenance? For preventative maintenance? Were common cause failure differences between corrective and preventive maintenance factored into the risk assessment of CDF and LERF increases (Tables 2 and 3 of the license amendment request)?

NMC response:

The original submittal did not provide information with respect to probabilistic assessment results for an extended EDG Completion Time for corrective maintenance. Supplemental information for this case is provided as follows.

Table 14-1
ICCDP and ICLERP for EDG
When EDG is Inoperable for Corrective Maintenance

Unit	DG Inoperable	ICCDP	ICLERP
1	D1	1.78E-07	< 5E-10
	D2	2.07E-07	< 5E-10
	D5	2.18E-07	< 5E-10
	D6	2.34E-07	< 5E-10
2	D1	2.38E-07	< 5E-10
	D2	1.67E-07	< 5E-10
	D5	3.22E-07	< 5E-10
	D6	*2.75E-07*	< 5E-10

The results from Table 14-1 show the ICCDP and the ICLERP assuming that an EDG is unavailable due to CM. The CM values assume elevated common cause failure (CCF) probabilities associated with the remaining operable EDG on each unit. It was assumed that the CCF for the remaining operable EDG on each unit is increased to the beta factor for the first 32 hours of the extended Completion Time of 14 days. For the remainder of the extended Completion Time, the nominal EDG failure rates were used.

Existing PINGP TS 3.8.1.Required Action B.3.1 requires that the possibility of common mode failure be ruled out soon after an EDG becomes inoperable by verifying no common cause or demonstrating the operability of the remaining EDG within 24 hours. If a common mode failure exists, both affected EDGs would be considered inoperable and TS 3.8.1 Required Action E.1 would be entered which allows 2 hours to restore an EDG to operability. If an EDG is not restored to operability within 2 hours, the affected unit is required to be in Mode 3 within 6 hours in accordance with TS 3.8.1 Condition F. Thus, operating with this condition is precluded for extended periods beyond 32 hours.

The CCF exposure time for the remaining operable EDG is dependent only on TS 3.8.1.Condition B.3.1 required actions and is independent of the EDG Completion Time. Thus, there is no increase in risk due to the CCF aspects of an EDG inoperable due to CM beyond 32 hours. Therefore, the ICCDP and ICLERP calculations for an EDG unavailable due to CM should be calculated assuming nominal EDG failure rates after the initial 32 hours of the extended Completion Time. These CM risk metrics were not used in the PINGP EDG extended Completion Time request; only the PM metrics apply to this request.

The ICCDP and ICLERP values calculated under the assumption that an EDG is unavailable due to PM assumed that CCF of the remaining operable EDG was set to

zero and the single failure probabilities of the remaining operable EDG were adjusted to reflect a smaller CCF group. As can be seen in Table 14-1 above, the ICCDP and the ILERP values are higher than those calculated assuming an EDG is unavailable due to PM (provided in Table 4 of the LAR November 21, 2005 submittal). In all cases however, the calculated ICCDP and ICLERP values are less than the values suggested RG 1.177, "An Approach for Plant Specific Risk-Informed Decisionmaking: Technical Specifications", August 1998..

Common cause failure differences were not factored into the delta CDF and delta LERF calculations in Tables 2 and 3 of the LAR dated November 21, 2005. Nominal common cause failure values were used in all delta CDF and delta LERF calculations. In these risk metrics, the change in the average annual CDF and LERF is calculated by increasing the preventive and corrective maintenance terms of the EDGs to account for the increased on-line maintenance unavailability that could result from the increased Completion Time. Since none of the EDGs have been considered unavailable due to PM or CM, nominal common cause failure rates are used.

As an addition to this question, a minor error was discovered that resulted in changes to previously reported delta CDF and delta LERF results in Table 2 of the original LAR and ICCDP and ICLERP results in Table 4 of the original LAR submitted November 21, 2005. The corrected original LAR submittal Table 2 and Table 4 can be found below as Table 14-2 and Table 14-3.

Table 14-2
Corrected Table 2 (from November 21, 2005 LAR)
ΔCDF and ΔLERF Results for Increased PM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 criteria
Base Line CDF	1.47E-05	1.63E-05	NA
Base Line LERF	5.74E-07	5.74E-07	NA
Delta CDF	1.80E-07	2.22E-07	<1E-6
Delta LERF	<5.0E-10	<5.0E-10	<1E-7

Table 14-3
Corrected Table 4 (from November 21, 2005 LAR)
ICCDP and ICLERP for EDG Inoperable for Preventive Maintenance

Unit	EDG Inoperable	ICCDP	ICLERP
1	D1	1.50E-07	< 5E-10
	D2	1.79E-07	< 5E-10

Unit	EDG Inoperable	ICCDP	ICLERP
	D5	1.99E-07	< 5E-10
	D6	2.15E-07	< 5E-10
2	D1	2.04E-07	< 5E-10
	D2	1.32E-07	< 5E-10
	D5	2.97E-07	< 5E-10
	D6	2.50E-07	< 5E-10

From observation of the corrected original November 21, 2005 LAR Table 2 above (Table 14-2), the calculated delta CDF and delta LERF values are less than the RG 1.174 values and the ICCDP and ICLERP values in the corrected original November 21, 2005 LAR Table 4 above (Table 14-3) are less than the RG 1.174 limits.

15. Why is the core damage frequency (CDF) at unit 2 higher than at unit 1? Why are the large early release frequency (LERF) values exactly the same? Please provide a summary of the differences between the units as they impact the calculation of these risk metrics.

NMC response:

A discussion of the Unit 1 and Unit 2 CDF and LERF results was provided in Exhibit E of the LAR submittal dated November 21, 2005.

The primary reason for the higher CDF for Unit 2 is the larger contribution of the loss of DC power Train A initiating event due to an asymmetry between the units' electrical power supplies to the AFW pumps. Both Unit 1 and Unit 2 main feedwater systems are dependent upon Train A DC (main feedwater is lost to the steam generators (SGs) if Train A DC is lost due to feedwater regulating valve and regulating bypass valve failure closed). In addition, the discharge of the motor-driven AFW pumps for both units have the ability to be cross-tied (via local manual operations) to supply AFW to the opposite unit if necessary. However, on Unit 2, the motor-driven AFW pump (21 AFW pump) is powered from the Train A 4 kV safeguards bus (Bus 25), which, in turn, is supplied with control power for breaker operation from Train A DC power. Therefore, on a Unit 2 loss of DC power Train A initiating event, it is possible for Unit 2 to lose all main feedwater and its dedicated motor-driven AFW pump, leaving only the turbine-driven pump and the Unit 1 motor-driven pump through the local, manual crosstie. This is not the case for Unit 1. The Unit 1 motor driven AFW pump (12 AFW pump) is powered from the Train B 4 kV safeguards bus (Bus 16), which is supplied with control power for breaker operation from Train B DC power.

The fact that the baseline LERF metrics for both units are reported as the same value is coincidence; although the LERF metric tends to be more uniform than the CDF metric

because it is only dominated by certain containment bypass events (intersystem LOCA (ISLOCA) and steam generator tube rupture (SGTR)), while the CDF metric is significantly influenced by a number of different initiating events. The piping arrangements that dominate the ISLOCA contribution to both CDF and LERF are substantially symmetrical between the units, as are the SGTR initiating event frequencies and the systems and operator actions credited in the mitigation of the SGTR event. The primary asymmetry between the units that impacts CDF (described above, the loss of DC power Train A initiating event) does not influence the LERF metric significantly because one train of containment systems remains available to provide containment pressure and temperature control, and all containment penetrations with DC power dependencies are either closed or fail in the closed position on loss of DC power.

16. Please provide a discussion on the effects of the proposed CT extension on dominant accident sequences (sequences that contribute more that 5% to risk, for example) to show that the proposed change does not create risk outliers or exacerbate existing risk outliers. Please provide core damage contributions by initiating event and by sequence type for the base case and the extended CT case.

NMC response:

The EDG at PINGP function only to supply a backup source of power to the plant 4 kV safeguards buses. This function is only required when both the normal and auxiliary sources of offsite power to those buses are lost. Loss of both offsite sources to any one bus, but not to the other buses, is not the event of concern. A more likely and more risk significant scenario is a loss of all offsite power (LOOP) to one unit or to both units at the site. Transient (including consequential anticipated transients without scram (ATWS) events), main steamline break, main feedwater line break, LOCA and SGTR initiating events do not require the functions provided by the EDGs. Seismic events would require a plant response similar to that of transients. Internal fire events also behave similar to transient events.

Therefore, extension of the Completion Time for the EDGs at PINGP will only affect those accident sequences that are initiated as a result of a LOOP. In addition, no new accident sequences are created; the only change that is possible is that the frequency of those sequences that involve EDG unavailability due to preventive maintenance will be increased slightly. Overall, this results in a slight increase in the core damage contribution from LOOP-initiated sequences relative to other sequences. This can be seen in Tables 16-1 and 16-2 below, where core damage contribution by initiating events from the baseline model are compared to that from the extended Completion Time model.

Table 16-1
Unit 1 Initiating Event CDF Contribution

Initiating Event	Baseline (per yr)	Extended Completion Time (per yr)
Normal Transient	4.10E-07	4.10E-07
Inadvertent "S" Signal	8.23E-08	8.23E-08
Loss of Main Feedwater	1.75E-06	1.75E-06
Loss of CL	5.19E-07	5.19E-07
Loss of CC	1.43E-07	1.43E-07
Loss of Train A DC	6.26E-08	6.26E-08
Loss of Train B DC	2.56E-08	2.56E-08
Loss of Instrument Air	5.74E-08	5.74E-08
Main Steamline Break	1.76E-08	1.76E-08
LOOP	1.45E-06	1.63E-06
ISLOCA	2.59E-07	2.59E-07
Large LOCA	2.80E-07	2.80E-07
Medium LOCA	3.76E-07	3.76E-07
Small LOCA	6.68E-06	6.68E-06
Random RCP Seal Failure	2.84E-07	2.84E-07
SGTR	2.10E-06	2.10E-06
Internal Flooding	2.44E-07	2.44E-07
Total	**1.47E-05**	**1.49E-05**

Table 16-2
Unit 2 Initiating Event CDF Contribution

Initiating Event	Baseline (per yr)	Extended Completion Time (per yr)
Normal Transient	6.98E-07	6.98E-07
Inadvertent "S" Signal	1.38E-07	1.38E-07
Loss of Main Feedwater	1.83E-06	1.83E-06
Loss of CL	5.18E-07	5.18E-07
Loss of CC	1.40E-07	1.40E-07
Loss of Train A DC	1.04E-06	1.04E-06

Initiating Event	Baseline (per yr)	Extended Completion Time (per yr)
Loss of Train B DC	5.55E-10	5.55E-10
Loss of Instrument Air	5.74E-08	5.74E-08
Main Steamline Break	1.80E-08	1.80E-08
LOOP	1.66E-06	1.88E-06
ISLOCA	2.59E-07	2.59E-07
Large LOCA	2.80E-07	2.80E-07
Medium LOCA	3.76E-07	3.76E-07
Small LOCA	6.68E-06	6.68E-06
Random RCP Seal Failure	2.84E-07	2.84E-07
SGTR	2.10E-06	2.10E-06
Internal Flooding	2.44E-07	2.44E-07
Total	**1.63E-05**	**1.65E-05**

The dominant accident sequences for the PINGP units (both baseline and Completion Time Extension cases) are shown in Tables 16-3 through 16-6 below.

Table 16-3
Unit 1 Dominant Accident Sequences (Baseline)

CD Sequence	Frequency	Class	Class Description	% CDF	Description
1SLOCA-SEQ3	6.68E-06	SLH	LOCA, Late core damage (CD) at High RCS Pressure	45%	Small LOCA, failure of primary and secondary depressurization or shutdown cooling, failure of Emergency Core Cooling System (ECCS) recirculation
1TRANS-SEQ4	1.87E-06	TEH	Transient, Early CD at High RCS Pressure	13%	Transient with loss of secondary heat sink, failure of high head RCS injection
1SGTR-SEQ3, 1SGTR-SEQ5	1.79E-06	GLH	SGTR, Late CD at High RCS Pressure	12%	SGTR, failure of RCS depressurization to prevent SG overfill, failure of RCS cooldown and depressurization for long term

CD Sequence	Frequency	Class	Class Description	% CDF	Description
					recovery
1SLOCA-SEQ6	9.56E-07	SEH	LOCA, Early CD at High RCS Pressure	6%	Small LOCA with failure of high head injection, failure of RCS depressurization (to establish ECCS low head recirculation conditions)
1SBO-SEQ8	7.72E-07	BEH	SBO, Early CD at High RCS Pressure	5%	SBO with failure to restore offsite power in time to prevent core uncovery (6 hours)

Table 16-4
Unit 2 Dominant Accident Sequences (Baseline)

CD Sequence	Frequency	Class	Class Description	% CDF	Description
2SLOCA-SEQ3	6.68E-06	SLH	LOCA, Late CD at High RCS Pressure	41%	Small LOCA, failure of primary and secondary depressurization or shutdown cooling, failure of ECCS recirculation
2TRANS-SEQ4	2.66E-06	TEH	Transient, Early CD at High RCS Pressure	16%	Transient with loss of secondary heat sink, failure of high head RCS injection
2SGTR-SEQ3, 2SGTR-SEQ5	1.79E-06	GLH	SGTR, Late CD at High RCS Pressure	11%	SGTR, failure of RCS depressurization to prevent SG overfill, failure of RCS cooldown and depressurization for long term recovery
2SLOCA-SEQ6	1.37E-06	SEH	LOCA, Early CD at High RCS Pressure	8%	Small LOCA with failure of high head injection, failure of RCS depressurization (to establish ECCS low head recirculation conditions)
2SBO-SEQ8	8.41E-07	BEH	SBO, Early CD at High RCS Pressure	5%	SBO with failure to restore offsite power in time to prevent core uncovery (6 hours)

Table 16-5
Unit 1 Dominant Accident Sequences (Completion Time Extension)

CD Sequence	Frequency	Class	Class Description	% CDF	Description
1SLOCA-SEQ3	6.68E-06	SLH	LOCA, Late CD at High RCS Pressure	45%	Small LOCA, failure of primary and secondary depressurization or shutdown cooling, failure of ECCS recirculation
1TRANS-SEQ4	1.87E-06	TEH	Transient, Early CD at High RCS Pressure	13%	Transient with loss of secondary heat sink, failure of high head RCS injection
1SGTR-SEQ3, 1SGTR-SEQ5	1.79E-06	GLH	SGTR, Late CD at High RCS Pressure	12%	SGTR, failure of RCS depressurization to prevent SG overfill, failure of RCS cooldown and depressurization for long term recovery
1SLOCA-SEQ6	9.59E-07	SEH	LOCA, Early CD at High RCS Pressure	6%	Small LOCA with failure of high head injection, failure of RCS depressurization (to establish ECCS low head recirculation conditions)
1SBO-SEQ8	8.87E-07	BEH	SBO, Early CD at High RCS Pressure	6%	SBO with failure to restore offsite power in time to prevent core uncovery (6 hours)

Table 16-6
Unit 2 Dominant Accident Sequences (Completion Time Extension)

CD Sequence	Frequency	Class	Class Description	% CDF	Description
2SLOCA-SEQ3	6.68E-06	SLH	LOCA, Late CD at High RCS Pressure	40%	Small LOCA, failure of primary and secondary depressurization or shutdown cooling, failure of ECCS recirculation
2TRANS-SEQ4	2.66E-06	TEH	Transient, Early CD at High RCS Pressure	16%	Transient with loss of secondary heat sink, failure of high head RCS injection

CD Sequence	Frequency	Class	Class Description	% CDF	Description
2SGTR-SEQ3, 2SGTR-SEQ5	1.79E-06	GLH	SGTR, Late CD at High RCS Pressure	11%	SGTR, failure of RCS depressurization to prevent SG overfill, failure of RCS cooldown and depressurization for long term recovery
2SLOCA-SEQ6	1.37E-06	SEH	LOCA, Early CD at High RCS Pressure	8%	Small LOCA with failure of high head injection, failure of RCS depressurization (to establish ECCS low head recirculation conditions)
2SBO-SEQ8	9.87E-07	BEH	SBO, Early CD at High RCS Pressure	6%	SBO with failure to restore offsite power in time to prevent core uncovery (6 hours)

Tables 16-3 through 16-6 clearly show that the impact on the dominant accident sequence breakdown is very minimal under the Completion Time extension case. No accident sequence experiences a large increase in CDF. Only the SBO sequence with extended loss of offsite power (1SBO-SEQ8 and 2SBO-SEQ8) increases by more than 1E-7/yr. The Small LOCA sequence with failure of high head injection and failure to establish RCS conditions to support recirculation (1SLOCA-SEQ6 and 2SLOCA-SEQ6) increases by about 2E-9/yr due to a slight increase in the likelihood of loss of RCP seal cooling from loss of one train of AC power in conjunction with hardware failures on the other train of equipment. Comparison of the Unit 1 and Unit 2 results in both the baseline and CT extension cases show no significant differences between the units relative to dominant accident sequences.

17. In section 4.4.2 of the LAR, it states "It is the intent of management at PINGP to limit the use of the extended Completion Time to no more than once per EDG per refueling cycle." The staff notes that the risk assessment uses this assumption as an input. However, this intention is not captured in the proposed revised Technical Specification pages or in the list of commitments. How do you propose to track this intention?

NMC response:

In order to perform PRA calculations supporting the EDG Completion Time LAR, assumptions on EDG unavailability must be made. As stated in Exhibit A, Section 4.4.2, it is NMC's intent that the extended Completion Time will be used once per refueling cycle. As discussed in the LAR dated November 21, 2005, Exhibit A Section 4.2, page 9, the extended Completion Time may reduce EDG unavailability as follows:

> The extended TS Completion Time for EDGs improves effectiveness of the

allowed maintenance period. A significant portion of on-line maintenance activities is associated with preparation and return to service activities, such as, tagging, fluid system drain down, fluid system fill and vent, and cylinder block heat-up. The duration of these activities is relatively constant. Longer Required Action Completion Time durations allows more maintenance to be accomplished during a given on-line maintenance period and therefore would improve maintenance efficiency. Thus the total EDG unavailability may be reduced with this proposed change.

The time that the EDGs are removed from service is tracked as part of PINGP's implementation of the Maintenance Rule and MSPI programs. The Maintenance Rule, 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants", requires monitoring of important systems, including the EDGs, and specifies performance criteria. PINGP's Maintenance Rule program includes corrective actions based on performance relative to the performance criteria. Causes for failing to meet performance criteria are found and corrected. The effectiveness of these actions is demonstrated by having the component meet goals. In the Maintenance Rule program the balance between availability and reliability is periodically assessed. All of these activities are inspected as part of the NRC Triennial Maintenance Rule Inspection.

Also, the MSPI measures EDG unavailability risk impact on a 36 month rolling average. MSPI is a new program; current plans for implementation at PINGP include an MSPI Review Board that will review failures and margins for each monitored system, including EDGs. The MSPI Review Board procedures recommend convening a Margin Review Board and taking corrective actions prior to reaching specified performance measures. Equipment unavailability and failures monitored by this program are periodically reported to the NRC.

Upon approval of this LAR, NMC will continue to schedule and perform EDG maintenance activities within the minimum practical time period. However the EDGs will be removed from service as deemed necessary to maintain their capacity and capability to perform their required safety functions.

18. The risk assessment appears to assume that the capability to cross-tie the 4 kV buses across the units is available. However, the proposed revised Technical Specification pages and the list of commitments does not address whether extended EDG CTs could be entered on both units at the same time. How do you propose to track this assumed availability of the other unit's 4 kV cross-tie capability under the proposed CT extension? Also, the risk assessment does not show plant configurations where an EDG from each unit is out of service at the same time. This implies that an extended CT would not be planned for more than one EDG at a given time. Is this the intent of PINGP? How do you proposed to track this analysis assumption?

NMC response:

NMC proposes commitments in support of this LAR provided in Enclosure 2 of this letter. The commitments in Enclosure 2 supersede the commitments originally provided in Exhibit D of the LAR and include a new commitment as follows:

> *The LCO statement requirements of TS 3.8.1 and TS 3.8.9, for safeguards AC buses, shall be met on the opposite unit (regardless of unit Mode) during the extended EDG Completion Time (required emergent corrective maintenance or TS required surveillance testing on EDGs, offsite paths or safeguards AC buses may be performed).*

Thus an EDG from only one unit will voluntarily be in an extended Completion Time at any time. This will be tracked by the plant work planners and operators.

19. Discuss and provide information on the reliability and availability of offsite power sources relating to the proposed change. Provide the basis the LOOP frequencies and non-recovery probabilities used in the probabilistic risk assessment (PRA) models. Were they adjusted as a result of the New York area blackout of August, 2003? If not, why not? How is the potential for loss of offsite power given a non-LOOP initiating event (e.g., "consequential LOOP") modeled in the PINGP PRA models? Please provide a sensitivity analysis of the risk assessment for the proposed EDG CT extension to a change in LOOP frequency.

NMC response:

Details associated with the reliability of the PINGP offsite power system are provided in response to Question 5. A description of the development of the LOOP frequency used in the EDG Completion Time extension risk analysis, including the inclusion of the Northeastern United States grid-related blackout events of August, 2003, is provided in the response to Question 12.

The potential for a non-LOOP initiating event to progress to a LOOP initiating event (consequential LOOP) was included in the LOOP initiating event frequency used in the risk assessment included with the Completion Time extension LAR submittal dated November 21, 2005. Data from then-draft NUREG/CR-INEEL/EXT-04-02326 was used to calculate the conditional probability of the consequential LOOP occurring. This conditional probability was multiplied by the initiating event frequency of each non-LOOP initiating event for one unit, with the results summed to obtain the plant specific value for PINGP. The initiating event frequencies for a single unit only were used, as the conditional probability of two non-LOOP initiating events occurring simultaneously is very low. The frequencies of consequential LOOP events were added to the LOOP frequency to obtain the overall probability of a LOOP event at PINGP (3.34E-2/yr).

A sensitivity analysis on the risk analysis results presented in the LAR was performed in which the LOOP initiating event frequency was increased to the industry mean

frequency reported in NUREG/CR-6890, Volume 1, Section 3.1 (5.61E-2/yr, a 68% increase over the LOOP frequency used in the risk analysis presented in the Completion Time extension LAR dated November 21, 2005). NUREG/CR-6890 develops two mean estimates, one for plants in operation and one for plants in a shutdown condition. The overall mean value reported is weighted based on the industry average fraction of time spent in operation versus shutdown condition during a given year.

The results of the sensitivity analysis are shown in Tables 19-1 through 19-3 below, which correspond to Tables 2, 3 and 4 from the original LAR dated November 21, 2005. Note that the "Baseline" cases include the LOOP initiating event frequency increased to the NUREG/CR-6890 value.

Table 19-1
ΔCDF and ΔLERF Results for Increased PM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 criteria
Base Line CDF	1.59E-05	1.77E-05	NA
Base Line LERF	5.74E-07	5.74E-07	NA
New CDF	1.63E-05	1.81E-05	NA
New LERF	5.74E-07	5.74E-07	NA
Delta CDF	3.09E-07	3.91E-07	<1E-6
Delta LERF	<5.0E-10	<5.0E-10	<1E-7

Table 19-2
ΔCDF and ΔLERF Results for Increased PM and CM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 criteria
Base Line CDF	1.59E-05	1.77E-05	NA
Base Line LERF	5.74E-07	5.74E-07	NA
New CDF	1.65E-05	1.84E-05	NA
New LERF	5.74E-07	5.74E-07	NA
Delta CDF	5.21E-07	6.68E-07	<1E-6
Delta LERF	<5.0E-10	<5.0E-10	<1E-7

Table 19-3
ICCDP and ICLERP for EDG
Inoperable for Preventive Maintenance

Unit	EDG Inoperable	ICCDP	ICLERP
1	D1	2.62E-07	< 5E-10
	D2	3.08E-07	< 5E-10
	D5	3.40E-07	< 5E-10
	D6	3.68E-07	< 5E-10
2	D1	3.48E-07	< 5E-10
	D2	2.25E-07	< 5E-10
	D5	5.13E-07	< 5E-10
	D6	4.29E-07	< 5E-10

The results presented in Tables 19-1 and 19-2 show that, even at the assumed higher LOOP frequency, the delta CDF and delta LERF results are all less than the RG 1.174 values for annual average CDF and LERF.

The results in Table 19-3 show that in most cases, even at the assumed higher LOOP frequency, the calculated ICCDP when an EDG is unavailable for PM is less than the 5E-07 criteria listed in RG 1.177. The only exception is the D5 EDG ICCDP for Unit 2. For this case only, the results slightly exceed the RG 1.177 limits of 5E-07.

Note that the results of a sensitivity analysis similar to the one requested in this question are provided in the response to Question 11. In that analysis, the HEP value for the operator action associated with cross-tie of the Unit 1 and Unit 2 4 kV buses (when one of the units has experienced an SBO) was increased by a factor of 10. Since this action is only required in response to a LOOP initiating event, where the EDGs on one unit are assumed to have failed or otherwise been unavailable, these sensitivity results also give insight to the impact of an increase in the LOOP frequency on the risk contribution of SBO events.

20. Please provide the results of an uncertainty analysis for the risk assessment of the proposed EDG CT extension. Alternately, provide a sensitivity analysis to key assumptions for this application.

NMC response:

The approved version of the PINGP PRA model that was used to support the EDG Completion Time extension LAR, Rev. 2.1, did not contain an uncertainty analysis.

Therefore, sensitivity analyses for key assumptions for the EDG Completion Time extension risk assessment are provided. Note that calculations presented above in support of the responses to Questions 11 and 19 contain such sensitivity analyses (for the bus cross-tie operator action HEP and the LOOP initiating event frequency, respectively). In addition, sensitivity of the overall risk metrics to the following key assumptions relative to SBO events was also investigated:

- Non-recovery probabilities for offsite power during SBO and non-SBO LOOP events
- Non-recovery probabilities for ECCS injection systems following offsite power recovery during SBO

The ECCS injection systems non-recovery probabilities following offsite power recovery (that is, not recovered in time to prevent core uncovery and core damage) is conditional upon the restoration of offsite power at any specified time after the onset of SBO. Therefore, a single sensitivity study was used to investigate the impact of an increase in all of these non-recovery probabilities simultaneously due to an increase in the assumed non-recovery probabilities for offsite power. Note that recovery of onsite power (diesel generators) is not credited in the PINGP PRA analysis.

For this sensitivity analysis, the basic events representing split fractions in the PRA model for non-recovery of offsite power were increased to NUREG/CR-6890, Volume 1, Table 4-1 (composite values for critical plant operation) values. The values used for these split fraction events in the risk assessment for the LAR submittal were based on an analysis of the data from EPRI TR-106306. In addition to the (complementary) offsite power recovery split fraction basic events, a number of other events in the PRA model that are dependent on the offsite power non-recovery event probabilities were recalculated (the only change to the calculation of these basic event probabilities was the increase in the offsite power non-recovery event probability inputs to those events).

The adjustments made to the offsite power non-recovery probabilities (and other dependent recovery probabilities) for this sensitivity analysis are shown in Table 20-1.

Table 20-1
Basic Event Values Adjusted to Perform Sensitivity Analysis

Basic Event	Description	Original Value	Sensitivity Value
0FAILROSP1Y	Failure to restore offsite power within 1 hour following LOOP	2.88E-01	5.30E-01
0NOTFROSP1Y	Offsite power restored within 1 hour following LOOP	7.12E-01	4.70E-01
0FAILROSP5Y	Failure to restore offsite power within 5 hours following LOOP	2.04E-01	2.26E-01

Basic Event	Description	Original Value	Sensitivity Value
0NOTFROSP5Y	Offsite power restored within 5 hours following LOOP	7.96E-01	7.74E-01
0FAILROSP6Y	Failure to restore offsite power within 6 hours following LOOP	1.71E-01	1.82E-01
0NOTFROSP6Y	Offsite power restored within 6 hours following LOOP	8.29E-01	8.18E-01
1SBOCN1COND 2SBOCN1COND	Conditional probability of core uncovery from an RCP LOCA 6 hours after SBO	3.35E-02	3.93E-02
1SBOCN2COND 2SBOCN2COND	Conditional probability of core uncovery from an RCP LOCA 5 hours after SBO	4.25E-02	4.96E-02
1SBOCN3COND 2SBOCN3COND	Conditional probability of core uncovery from an RCP LOCA 1 hour after SBO	2.83E-02	2.83E-02
0LOOP1HRRCV	Offsite power not recovered within 1 hour for LOOP with loss of secondary cooling	2.88E-01	5.30E-01
0LOOP2HRRCV	Offsite power not recovered within 2 hours for LOOP with loss of secondary cooling	1.73E-01	3.18E-01
0LOOP8HRRCV	Offsite power not recovered within 8 hours for LOOP with loss of secondary cooling	3.40E-02	6.70E-02

Tables 20-2 through 20-4, which correspond to Tables 2, 3, and 4 from the original November 21, 2005 LAR submittal, provide the key results of the cases run for Question 20. Note that the "Baseline" case includes the offsite power non-recovery probability values (and the other PRA model events dependent on these probabilities) increased to their sensitivity values (as shown in Table 20-1 above).

Table 20-2
Offsite Power Non-Recovery Sensitivity
ΔCDF and ΔLERF Results for Increased PM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 criteria
Base Line CDF	1.64E-05	1.82E-05	NA
Base Line LERF	5.74E-07	5.74E-07	NA
New CDF	1.67E-05	1.86E-05	NA
New LERF	5.74E-07	5.74E-07	NA
Delta CDF	3.51E-07	4.47E-07	<1E-6

Delta LERF	< 5E-10	< 5E-10	<1E-7

Table 20-3
Offsite Power Non-Recovery Sensitivity
ΔCDF and ΔLERF Results for Increased PM and CM

Risk Parameter	Unit 1 (per yr)	Unit 2 (per yr)	RG 1.174 criteria
Base Line CDF	1.64E-05	1.82E-05	NA
Base Line LERF	5.74E-07	5.74E-07	NA
New CDF	1.69E-05	1.89E-05	NA
New LERF	5.74E-07	5.74E-07	NA
Delta CDF	5.91E-07	7.59E-07	<1E-6
Delta LERF	< 5E-10	< 5E-10	<1E-7

Table 20-4
Offsite Power Non-Recovery Sensitivity
ICCDP and ICLERP for EDG
Inoperable for Preventive Maintenance

Unit	EDG Inoperable	ICCDP	ICLERP
1	D1	3.02E-07	< 5E-10
	D2	3.52E-07	< 5E-10
	D5	3.88E-07	< 5E-10
	D6	4.19E-07	< 5E-10
2	D1	3.94E-07	< 5E-10
	D2	2.58E-07	< 5E-10
	D5	5.83E-07	< 5E-10
	D6	4.90E-07	< 5E-10

The results presented in Table 20-2 and 20-3 show that, even at the assumed higher offsite power non-recovery probabilities from NUREG/CR-6890, the delta CDF and delta LERF results are all less than the RG 1.174 guidance for annual average CDF and LERF.

The results in Table 20-4 show that in most cases, even at the assumed higher offsite power non-recovery probabilities from NUREG/CR-6890, the calculated ICCDP when an EDG is unavailable for PM is less than the 5E-07 guidance of RG 1.177. The only exception is the D5 EDG ICCDP for Unit 2. For this case only, the results slightly exceed the RG 1.177 guidance.

The results of these sensitivity studies demonstrate the low risk significance of the EDG Completion Time extension. This is due to the robust design of the electrical system, including a dedicated EDG for each safeguards 4 kV bus, the ability to cross-tie the train-related buses across units, and the ability of each EDG to handle the total load expected for both units (on that train) during a single or dual unit LOOP event.

21. The proposed Technical Specification change would increase the EDG CT from 7 to 14 days. The proposed change also seeks to increase the LCO "total time" to 21 days, but no basis for this increase has been provided. The risk assessment does not appear to consider the risk of combinations of LCO parts (e.g., offsite power source; EDG) that combine for a 21 day LCO total time. Please provide a justification for the requested increase in "total time" and a risk assessment of the possible combinations of LCO parts that could result in the 21 day total time.

NMC response:

The second Completion Time "total time" was increased in the proposed TS revisions to be consistent with the guidance of NUREG-1431, Standard Technical Specifications, Westinghouse Plants", Revision 1.0 which provided the guidance for conversion of the PINGP TS and the use of second Completion Times in the PINGP TS. The second Completion Time applies "from discovery of failure to meet LCO" for both TS 3.8.1 Condition A.2 and Condition B.4.

The total allowed time in the second Completion Time is the simple addition of the Completion Time for each of the conditions which can be entered within the same specification, that is, for PINGP TS 3.8.1 with the proposed Completion Time extension, the second Completion Time total time is the addition of 7 days from Condition A and 14 days proposed for Condition B. The 7-day Completion Time for Condition A has been previously approved for the PINGP TS and does not require further justification. The 14-day Completion Time has been justified by a risk assessment in the LAR submittal dated November 21, 2005.

The 7-day Completion Time and 14-day Completion Time can be simply added regardless of the means by which they were developed. The NRC has previously approved this approach in the approval of Technical Specifications Task Force (TSTF) Standard Technical Specifications Traveler TSTF-430, "AOT Extension to 7 Days for LPI and Containment Spray (BAW-2295-A, Rev. 1)". This traveler stated:

The "modified time zero" Completion Times in Specification 3.6.6, Conditions A and C are revised from 10 days to 14 days. The "discovery of failure to meet the LCO" Completion Times are an administrative limit intended to prevent plants from successively entering and exiting ACTIONS associated with different systems governed by one LCO without ever meeting the LCO (i.e., "flip flopping"). The "discovery of failure to meet the LCO" Completion Times are the sum of the Conditions which can be successively entered, in this case Specification 3.6.6, Conditions A and C. These administrative limits are calculated without regard to the method used to determine the component Completion Times. Therefore, an extension of one of the component Completion Times will result in a corresponding extension of the "discovery of failure to meet the LCO" Completion Time. This portion of the change is consistent with the Staff's approval of Grand Gulf Nuclear Station, Unit 1, Amendment 151, dated July 16, 2002.

Thus the addition of the 7-day Completion Time from TS 3.8.1 Condition A.2 to the proposed 14-day Completion Time for Condition B.4 provides the correct total time limit of 21 days in accordance with the guidance of NUREG-1431, Revision 1, NRC approved TSTFs and the cited NRC approved LAR.

Table of Acronyms

AFW	Auxiliary Feedwater
ATWS	Anticipated Transient Without Scram
CAP	Corrective Action Program
CBTM	Caused Based Decision Tree Methodology
CC	Component Cooling Water
CCF	Common Cause Failure
CCHX	Component Cooling Water Heat Exchanger
CD	Core Damage
CDF	Core Damage Frequency
CM	Corrective Maintenance
CRMP	Configuration Risk Management Program
DBA	Design Basis Accident
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOOS	Equipment Out of Service
EPRI	Electric Power Research Institute
HRA	Human Reliability Analysis
ICCDP	Incremental Conditional Core Damage Probability
ICLERF	Incremental Conditional Large Early Release Frequency
ISLOCA	Intersystem Loss of Coolant Accident
LAR	License Amendment Request
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LERF	Large Early Release Frequency
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MCC	Motor Control Center
MRFF	Maintenance Rule Functional Failures
MSPI	Mitigating System Performance Index
NMC	Nuclear Management Company
PINGP	Prairie Island Nuclear Generating Plant
PM	Preventive Maintenance
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
S/G	Safeguards
SACM	Societe Alsacienne de Constructions Mecaniques de Mulhouse
SBO	Station Blackout
SG	Steam Generator
SGTR	Steam Generator Tube Rupture
SR	Surveillance Requirement
TS	Technical Specifications
USAR	Updated Safety Analysis Report
VR	Voltage Restoration

Enclosure 2
LIST OF COMMITMENTS

REGULATORY COMMITMENT	DUE DATE
Procedures shall be established to assure that the following provisions are invoked when an emergency diesel generator (EDG) is inoperable for an extended Completion Time in TS 3.8.1 Condition B: • The condition of the offsite power supply and switchyard will be evaluated prior to entering the extended EDG Completion Time for elective maintenance. NMC will develop a procedure to determine acceptable grid conditions for entering an extended EDG Completion Time to perform elective maintenance. An extended EDG Completion Time will not be entered to perform elective maintenance when grid stress conditions are high such as during extreme summer temperatures or high demand. • No elective maintenance will be scheduled in the switchyard that would challenge offsite power availability and no elective maintenance will be scheduled on the main, auxiliary or startup transformers associated with the unit during the proposed extended EDG Completion Time. • The system dispatcher will be contacted once per day to ensure no significant grid perturbations are expected during the extended EDG Completion Time. The system dispatcher will be ~~and~~ informed of the EDG status, ~~along with~~ the power needs of the facility and requested to inform PINGP if conditions change such that unacceptable voltage would occur following a unit trip. • The LCO statement requirements of TS 3.8.1 and TS 3.8.9, for safeguards AC buses, will be met on the opposite unit (regardless of Mode) during the extended EDG Completion Time (required emergent corrective maintenance or TS required surveillance testing on EDGs, offsite paths or safeguards AC buses may be performed). • The turbine driven AFW pump on the associated unit will not be removed from service for planned maintenance activities during the extended EDG Completion T~~t~~ime.	Implementation date of the license amendment requested in letter PI-05-036

• Assure operating crews are briefed on the EDG work plan and procedural actions regarding: o LOOP and SBO o 4 kV safeguards bus cross-tie o Reactor Coolant System bleed and feed. • Weather conditions will be evaluated prior to entering the extended EDG Completion Time for elective maintenance. An extended EDG Completion Time will not be entered for elective maintenance purposes if official weather forecasts are predicting severe conditions (tornado or thunderstorm warnings). • Three safeguards cooling water (CL) pumps will be operable when a Unit 2 EDG is in an extended Completion Time, except required emergent corrective maintenance or TS required surveillance testing on safeguards CL pumps or Unit 2 EDGs may be performed if required.	

Enclosure 3

HRA Evaluation for Event 0AMNVLTRXXY

7 pages follow

Enclosure 3
HRA Evaluation for Event 0AMNVLTRXXY

0AMNVLTRXXY, Operator Fails To Perform Manual V.R. From Opposite Unit

Cognitive Method	Date	Analyst
CBDTM/THERP	**04/23/05**	**J. F. Grobbelaar, SCIENTECH**

HEP Summary				
	P_{cog}	P_{exe}	Total HEP	Error Factor
Without Recovery	1.0e-03	2.6e-02		
With Recovery	1.4e-04	3.9e-03	4.0e-03	5

HFE Scenario Description
1. Initial Conditions: Steady state, full power operation. 2. Initiating Event: LOOP with loss of safeguards bus voltage 3. Accident sequence (preceding functional failures and successes): Reactor trip (reactor trip and bypass breakers are open). Turbine trip (both turbine stop valves are closed). Both safeguards buses are de-energized. SI is not actuated and not required. AFW flow greater than 200 gpm. Safeguards buses 15 and 16 are available for sequencer loading. Unit 1 diesel generators fail to start. Unit 2 bus tie breakers available. 4. Preceding operator error or success in sequence: Entered 1ECA-0.0 and performed steps 1 to 6 5. Operator action success criterion: Restore power to any available safeguards bus from Unit 2: 6. Consequence of failure: Core damage for affected unit

Cues and Indications	
Cue/s	Loss of safeguards bus voltage
Degree of Clarity	Very Good

Procedures and Training	
Cognitive Procedure	1ECA-0.0
Cognitive Step Number	7
Cognitive Instruction	Attempt To Restore Power To Any Available Safeguards Bus From Unit 2:
Execution Procedure	1ECA-0.0
Other Procedure	
Job Performance Measure	EA-17S
Classroom Training	Frequency: .5 per year
Simulator Training	Frequency: .5 per year

Notes

1ECA-0.0 is entered anytime power is lost to both safeguards buses after the reactor and turbine have been verified tripped (immediate, memorized actions). The operators would not enter 1E-0 first, before going to 1ECA-0.0.

JPM EA-17S is not directly applicable to this action, as the Unit 2 cross tie is set up to fail to force the operators to continue in ECA-0.0 and try other restoration actions. The JPM time of 15 minutes is therefore not applicable, as the actual time would be less.

Timing Analysis	
T_{sw}	60 Minutes
T_{delay}	9 Minutes
$T_{1/2}$	0 Minutes
T_M	1 Minutes
Time available for recovery	50 Minutes
SPAR-H Available time (cognitive)	50 Minutes
SPAR-H Available time (execution) ratio	51 Minutes
Minimum level of dependence for recovery	LD

Notes
Per the SBO event tree notebook: "Heading 1HR models the probability of an operator restoring offsite AC power within 1 hour following a SBO. It is applied to all SBO accident sequences and is not dependent on the status of the turbine driven AFW pump supplying water to the steam generator. One hour was chosen rather than the 2 hours, which was used in the IPE SBO event tree, as a catastrophic reactor coolant pump (RCP) seal LOCA could occur during the first hour following an SBO. (Reference 6) This would cause depletion of the RCS inventory and subsequent core damage". The system time window is based on the "1HR" heading in the event tree. Per the operator interviews, there is a USAR commitment to complete this action within 10 minutes, and in practice, this is accomplished within 10 minutes on the simulator. The total delay plus manipulation time is therefore 10 minutes or less. Therefore: Tsw = 60 minutes. Td = 9 minutes Tm = 1 minute

Dependencies (Related Human Interactions)
N/A

Cognitive Analysis		
Pc Failure Mechanism	**Branch**	**HEP**
P_{ca}: Availability of Information	a	neg.
P_{cb}: Failure of Attention	h	neg.
P_{cc}: Misread/miscommunicate data	a	neg.
P_{cd}: Information misleading	a	neg.
P_{ce}: Skip a step in procedure	a	1.0e-03
P_{cf}: Misinterpret Instructions	a	neg.
P_{cg}: Misinterpret decision logic	k	neg.
P_{ch}: Deliberate violation	a	neg.
Initial P_c(without recovery credited)		1.0e-03
Notes		
Cognitive Complexity	Simple	
Equipment Accessibility	Main Control Room: Accessible	

Cognitive Recovery											
	Initial HEP	**Self Review**	**Extra Crew**	**STA Review**	**Shift Change**	**ERF Review**	**Recovery Matrix**	**Dependency Level**	**Multiply HEP By**	**Override Value**	**Final Value**
Pc_a	neg.	-	-	-	-	-	NC	-	1.0		
Pc_b	neg.	-	-	-	-	-	NC	-	1.0		
Pc_c	neg.	-	-	-	-	-	NC	-	1.0		
Pc_d	neg.	-	-	-	-	-	NC	-	1.0		
Pc_e	1.0e-03	X	-	-	-	-	1.0e-01	MD	1.4e-01		1.4e-04
Pc_f	neg.	-	-	-	-	-	NC	-	1.0		
Pc_g	neg.	-	-	-	-	-	NC	-	1.0		
Pc_h	neg.	-	-	-	-	-	NC	-	1.0		
Final Pc (with recovery credited)											1.4e-04
Notes											
Self review recovery is credited based on ECA-0.0 step 10 "Attempt To Restore Power To Any Safeguards Bus From Unit 2"											

Execution Performance Shaping Factors		
Environment	Lighting	Emergency
	Heat	Normal
	Radiation	Background
	Atmosphere	Normal
Equipment Accessibility	Main Control Room	Accessible
Stress	High	
Notes		
Execution Complexity	Simple	

Execution Unrecovered								
Procedure: 1ECA-0.0,		Error Type	THERP		HEP	Stress Factor	Over Ride	Total HEP
Step No.	Instruction		Table	Item				
7.b	Place safeguards bus source breakers for available bus to "PULLOUT": Comments: Regarded as a single perceptual unit: 1) 1R source 2) CT11 source 3) DG source	EOM	20-7b	2	1.3e-02	5		1.3e-02
		EOC	20-12	3	1.3E-3			
7.d	Close 4KV bus tie breakers for available bus: Comments: Regarded as a single perceptual unit 1) Unit 2 bus tie breaker 2) Unit 1 bus tie breaker	EOM	20-7b	2	1.3e-02	5		1.3e-02
		EOC	20-12	3	1.3E-3			
11	Attempt To Restore Power To Any Safeguards Bus From Unit 2 Comments:	EOM	20-7b	2	6.5e-03	5		6.5e-03

Execution Recovered							
Critical Step No.	Recovery Step No.	Action	HEP (Crit)	HEP (Rec)	Dep.	Cond. HEP (Rec)	Total for Step
7.b		Place safeguards bus source breakers for available bus to "PULLOUT":	1.3e-02				1.9e-03
	11	Attempt To Restore Power To Any Safeguards Bus From Unit 2		6.5e-03	MD	1.5e-01	
7.d		Close 4KV bus tie breakers for available bus:	1.3e-02				1.9e-03
	11	Attempt To Restore Power To Any Safeguards Bus From Unit 2		6.5e-03	MD	1.5e-01	
		Total Unrecovered:	2.6e-02			**Total Recovered:**	3.9e-03