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SOUTHERN COMPANY

July 30, 2012

Docket Nos.: 50-348

NL-12-1571

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, D. C. 20555-0001

<u>Joseph M. Farley Nuclear Plant Unit 1</u>
<u>Notice of Enforcement Discretion</u>

Ladies and Gentlemen:

On July 26, 2012, pursuant to the Nuclear Regulatory Commission (NRC) Inspection Manual, Part 9900, Southern Nuclear Operating Company (SNC) requested that a Notice of Enforcement Discretion (NOED) be granted for Joseph M. Farley Nuclear Plant (FNP) Unit 1. The need for a NOED occurred due to an unforeseen emergent plant condition, the mechanical failure of the 1B diesel generator (DG). The duration of the repair was expected to take longer than the Technical Specification (TS) Limiting Condition for Operation (LCO) 3.8.1 Required Action B.4 time limit of 10 days.

To prevent unit shutdown and the unnecessary transient associated, a NOED was requested for one-time enforcement discretion of LCO 3.8.1 for a duration of no longer than 66 hours. Surveillance verified operability of the 1B DG, enabling exit of LCO 3.8.1 at 23:32 CDT on July 28, 2012.

Subsequent discussion with the NRC staff resulted in an impasse with regard to the Branch Technical Position (BTP) 8-8 "Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions" and its requirement to have a second DG available. FNP was not able to procure a DG of required size, develop procedures, and train personnel in the time remaining for the LCO. As a result, the NRC staff denied SNC's request during a telephone call at 17:00 CDT on July 26, 2012, due to requirements contained in BTP 8-8.

During that telephone call, SNC made a commitment to provide a written NOED request within two working days of the NRC decision. The Enclosure to this letter satisfies that commitment by providing SNC's written NOED request for FNP.

This letter contains no NRC commitments. If you have any questions, please contact Doug McKinney at (205) 992-5982.

Sincerely,

Mark J Ajluni

M. J. Ajluni
Nuclear Licensing Director

MJA/jls/lac

Enclosure: Request for Enforcement Discretion

cc: Southern Nuclear Operating Company
Mr. S. E. Kuczynski, Chairman, President & CEO
Mr. D. G. Bost, Executive Vice President & Chief Nuclear Officer
Mr. T. A. Lynch, Vice President – Farley
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U. S. Nuclear Regulatory Commission
Mr. V. M. McCree, Regional Administrator
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Mr. E. L. Crowe, Senior Resident Inspector – Farley

Alabama Department of Public Health
Dr. D. E. Williamson, State Health Officer

Joseph M. Farley Nuclear Plant Unit 1

Enclosure

Request for Enforcement Discretion

Background

On July 16, 2012 at 21:52 Farley entered voluntary Limiting Condition for Operation (LCO) 3.8.1 and took 1B diesel generator (DG) out of service for the 24-month maintenance activities. Five days into the Required Action Statement (RAS) maintenance was completed and the DG entered a post maintenance run. Approximately two hours into the run, just after reaching full load, the diesel tripped on high crank case pressure. Based on initial inspections, abnormal indications were seen on seven of twelve cylinders. Metallic debris believed to be from the piston was found in the lube oil strainer.

An Issue Response Team was formed to investigate the cause of the 1B DG trip. It was determined that the cause of the damage was related to overheating of the engine due to mechanical failure of the intercooler heat exchanger thermostatic bypass valve. The intercooler heat exchanger thermostatic bypass valve did not function properly which prevented adequate cooling of the intercooler system.

Required Action B.4 Completion Time requires that the 1B DG be restored to Operable status in 10 days and Required Action H requires, if the required action and Completion Time is not met, to be in Mode 3 in six hours and be in Mode 5 in thirty-six hours.

To prevent unit shutdown, an emergency Technical Specification (TS) was submitted. Subsequent discussion with the Nuclear Regulatory Commission (NRC) staff resulted in a question that could not be resolved with a deterministic approach. The emergency TS request was based on a deterministic approach. This Notice of Enforcement Discretion (NOED) request uses a significantly different approach based on risk and use of state-of-the-art probabilistic risk assessment (PRA) modeling. This approach is very different because it requests less time, is risk-based, and has different compensatory measures.

1. Identify the Technical Specification or other License Conditions that will be violated.

Technical Specification (TS) 3.8.1, "AC Sources - Operating" requires two diesel generator sets per unit to be capable of supplying the onsite Class 1E power distribution subsystem(s) in Modes 1 through 4.

Farley Nuclear Plant (FNP) entered TS 3.8.1 Condition B on July 16, 2012 at 21:52 hours for a planned maintenance outage. All Required Actions of TS 3.8.1 were met and are currently being met within the allotted Completion Times. The 10-day allowed outage time expires at 21:52 on July 26, 2012.

The proposed enforcement discretion addresses the 10-day Completion Time specified for Condition B of TS 3.8.1, "AC Sources – Operating." Specifically, the 10-day allowed completion time for Condition B.4 (i.e., One Diesel Generator inoperable) would be extended an additional 66 hours on a one-time only basis.

NRC Inspection Manual Part 9900: "Technical Guidance" states that an NOED request may be considered by the staff only if it is not possible to resolve the situation with an emergency license amendment provided that the licensee has not abused the emergency provisions of 10 CFR 50.91 by failing to apply for an amendment (including an exigent or emergency amendment) in a timely manner.

SNC meets this provision of Part 9900 because a timely emergency license amendment was requested on July 23, 2012, approximately three days before the TS 3.8.1 Required Action B.4 expires at 21:52 on July 26, 2012. At the time of the emergency amendment request, five days (120 hours) extension to the TS Completion Time was requested based on a deterministic basis with risk insights for compensatory measures. Since the emergency amendment request, the repair efforts have progressed so that now 66 hours is being requested for the NOED which is based on a quantitative risk analysis. SNC plans to withdraw the emergency amendment request submitted on July 23, 2012 (NL-12-1552) and July 25, 2012 (NL-12-1567). SNC could not have foreseen the need for an emergency TS or this NOED request. The failure of the DG was without warning and halfway through the LCO period, shorting the time available for repair. In addition, the repairs have been challenging. Now that the extent of damage is known and the DG is nearly assembled, a success path is known. Trending of the 1-2A and 2B DG will be performed.

2. **Identify the circumstances surrounding the situation including the likely causes, the need for prompt action, the action taken in an attempt to avoid the need for an NOED, and the identification of any relevant historical events.**

The Unit 1B DG was declared inoperable on July 16, 2012 at 21:52 for a scheduled maintenance outage. During this outage, a 24-month preventative maintenance (PM) task was performed. Five days into the Required Action Statement (RAS) maintenance was completed and the DG entered a post maintenance run. Approximately two hours into the run just after reaching full load the diesel tripped on high crank case pressure. Based on initial inspections, abnormal indications were seen on seven of twelve cylinders. Metallic debris believed to be from the piston was found in the lube oil strainer.

An Issue Response Team was formed to investigate the cause of the 1B DG trip. A troubleshooting plan was developed and possible fault tree paths identified. Damage due to overheating was only observed in the # 12 cylinder.

It was determined that the root cause of the damage was overheating of the engine due to mechanical failure of the intercooler heat exchanger bypass valve. The thermostatic bypass valve did not function properly which prevented adequate cooling of the intercooler system. As a corrective action the valve was repaired.

Prompt action is needed to avoid undesirable transients potentially associated with a Unit 1 shutdown due to TS compliance for an issue with negligible risk as indicated by the risk assessment and compensatory measures.

Actions taken to avoid the need for a Notice of Enforcement Discretion (NOED) include efforts to develop a comprehensive troubleshooting plan and 24-hour work coverage during the maintenance, troubleshooting, repair, and testing activities. Additional maintenance, engineering, management, and vendor personnel were brought to the Farley site to support efforts to return the diesel generator to service. Parts were quickly identified and brought to the site to support a timely repair schedule. A monitoring program was developed to confirm proper operation of the 1B DG. The nature of the failure resulted in a major teardown and inspection of the diesel. Monitoring helps ensure that it was assembled correctly and allows for trending.

The following parameters will be measured at 30 minute increments during the maintenance runs of the 1B DG with installed plant equipment: generator bearing temperatures, generator bearing oil levels, lube oil filter and strainer dP, lube oil pressure, lube oil sump level, lube oil temperature, crankcase vacuum, Service Water pressure, jacket water pressure and temperature, jacket water expansion tank level, fuel oil pressure, fuel oil filter dP, scavenging air pressure, cylinder exhaust temperatures, turbo charger oil levels, intercooler pump discharge pressure, fuel rack position on all cylinders, air box intercooler inlet and outlet temperatures, Service Water temperatures, outside air temperatures, and phase current reading on the output of the generator.

The following parameters will be measured at 30-minute intervals during the maintenance runs of the 1B DG with temporary measuring devices such as temperature guns, installed recorders: Lube oil thermostatic bypass valve temperatures, jacket water thermostatic bypass valve temperatures, intercooler thermostatic bypass valve temperatures, and electronic governor output signals.

Specific instruments are identified for each of these readings as well as acceptance criteria. Depending on the parameter, various actions are specified to take if the acceptance criterion is exceeded up to and including engine shutdown.

SNC will monitor the cylinder exhaust temperature on the 1-2A DG and 2B DG, until the thermostatic valves are replaced.

There are no previous historical events at FNP that are relevant to this NOED.

3. Include information to show that the cause and proposed path to resolve the situation are understood by the licensee such that there is a high likelihood that planned actions to resolve the situation can be completed within the proposed NOED timeframe.

During the investigation it was determined that the 1B DG failure was due to mechanical failure of the intercooler heat exchanger thermostatic bypass valve. This failure resulted in overheating of the engine and damage to the #12 cylinder liner and piston. As a result of these findings, the damaged cylinder liner and piston have been replaced. In addition, SNC conducted additional inspections of the other cylinders, measurements of the liner, and oil sampling to verifying the cause and to justify reassembly.

All 12 piston and liners have been inspected by either boroscope or by disassembly. The following components have been investigated and eliminated as a cause of the event:

> Intercooler shaft driven pump, fuel rack linkages, fuel racks, fuel injector nozzles, fuel Injector pumps, lube oil, turbocharger, grid disturbance, jacket water cooling, and fuel oil.

Failure of the intercooler heat exchanger thermostatic bypass valve for the 1B DG was the first failure in the last 13 years, there have been only three instances of corrective maintenance related to these valves for the 1-2A DG, 1B DG, and the 2B DG. Two of those instances occurred on the 1-2A DG, with the most recent one in 1999. The 1B DG is the third event. Overall, failure of this valve is infrequent.

SNC has completed inspections and repair work for the 1B DG and the critical path is lube oil flush. However, the diesel generator reassembly and maintenance testing involves several major activities. Steps to return the diesel to operable status include:

1.	Lube oil flush completed	7/26
2.	Jacket water system returned to service	7/26
3.	Lube oil system returned to service	7/26
4.	Start first maintenance run (5 minute, 10 minute, 30 minute, 6-hour run with special fuel additive , 20-hour run without fuel additive, 5-hour DG load run, 4-hour post maintenance run)	7/26
5.	Complete maintenance runs	7/28
6.	Commence Operability surveillance test	7/28
7.	Exit LCO	7/28

Note: 1B DG will be considered available prior to starting the surveillance test.

These activities will be worked around-the-clock until 1B DG Operability is restored. A small amount of contingency (approximately 18 hours) is provided to prevent time pressure from impacting productivity and quality of workmanship.

4. Provide the safety basis for the request, including an evaluation of the safety significance and potential consequences of the proposed course of action.

The safety basis for this request for enforcement discretion is based on the fact that continued operation of the plant during the period of enforcement discretion will not cause risk to exceed the level determined acceptable during normal work controls: therefore, there is no net increase in radiological risk to station personnel and the public.

a. Use the zero maintenance PRA model to establish the plant's baseline risk and the estimated risk increase associated with the period of enforcement discretion. For the plant-specific configuration the plant intends to operate in during the period of enforcement discretion, the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) should be quantified and compared with guidance thresholds of less than or equal to an ICCDP of 5E-7 and an ICLERP of 5E-8. These numerical guidance values are not pass-fail criteria.

<u>Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) Determination</u>

The Farley Unit 1 zero maintenance internal events probabilistic risk assessment (PRA) model, revision 9, and the Farley Fire PRA model developed for NFPA-805 transition with credit for committed plant modifications were used to estimate the impact on risk of the period of enforcement discretion. Core Damage Frequency (CDF), Large Early Release Frequency (LERF), Incremental Conditional Core Damage Probability (ICCDP), and Incremental Conditional Large Early Release Probability (ICLERP) were estimated as listed below:

ICCDP and ICLERP were calculated using the following equations:

$$ICCDP = (CDF_{Equip\ OOS} - CDF_{Baseline}) \times (\text{Duration in hrs}/8760)$$
$$ICLERP = (LERF_{Equip\ OOS} - LERF_{Baseline}) \times (\text{Duration in hrs}/8760)$$

The acceptance criteria for ICCDP and ICLERP are
ICCDP < 5E-7 and ICLERP < 5E-8

The maximum allowable duration of a NOED is estimated as follows:

$$\text{Duration (hrs)} \leq \min[(5E\text{-}7*8760)/(CDF_{Equip\ OOS} - CDF_{Baseline}), (5E\text{-}8*8760)/(LERF_{Equip\ OOS} - LERF_{Baseline})]$$

1) Duration based only on internal event PRA risk

$(CDF_{Equip\ OOS} - CDF_{Baseline})_{Internal}$ = 1.44E-05 - 7.34E-06 = 7.06E-06
$(LERF_{Equip\ OOS} - LERF_{Baseline})_{Internal}$ = 1.47E-07 - 1.16E-07 = 3.10E-08
$Duration_{internal} \leq$ min[(5E-7*8760)/ 7.06E-06, (5E-8*8760)/ 3.10E-08] = min(620, 14129) = 620 hours

2) Duration based only on fire event PRA risk

$(CDF_{Equip\ OOS} - CDF_{Baseline})_{fire}$ = 9.64E-05 - 3.80E-05 = 5.84E-05
$(LERF_{Equip\ OOS} - LERF_{Baseline})_{fire}$ = $(CDF_{Equip\ OOS} - CDF_{Baseline})_{fire} \times CCFP$
= 5.84E-05 x 2.41E-02 = 1.41E-06

Where, Conditional Containment Failure Probability (CCFP) as defined in the average fire PRA model is computed as:

$CCFP_{fire} = LERF_{fire\text{-}average\ model} / CDF_{fire\text{-}average\ model}$
= 1.26E-06 / 5.24E-05 = 2.41E-02

$Duration_{fire} \leq$ min[(5E-7*8760)/5.84E-05, (5E-8*8760)/1.41E-06] = min(75, 310) = 75 hours

3) Duration based on internal and fire events PRA combined risk

$(CDF_{Equip\ OOS} - CDF_{Baseline})_{internal+fire}$ = 7.06E-06 + 5.84E-05 = 6.55E-05
$(LERF_{Equip\ OOS} - LERF_{Baseline})_{internal+fire}$ = 3.10E-08 + 1.41E-06 = 1.44E-06
$Duration_{fire} \leq$ min[(5E-7*8760)/ 6.55E-05, (5E-8*8760)/1.44E-06] = min(66, 304) = 66 hours*

*Note: 66 hours is a bounding duration since it includes 30 hours of DG 1B test run time during which time the 1B DG would be considered available. The actual risk incurred for the period of enforcement discretion is based on 36 hours. For 36 hours ICCDP and ICLERP are estimated to be 2.69E-7 and 5.92E-9, respectively.

b. Discuss the dominant risk contributors (cut sets/sequences) and summarize the risk insights for the plant-specific configuration the plant intends to operate in during the period of enforcement discretion. This discussion should focus primarily on risk contributors that have changed (increased or decreased) from the baseline model as a result of the degraded condition and resultant compensatory measures, if any.

Internal Events Results

Table b-1 shows the changes in contribution from the internal initiating events when 1B DG is out of service. As shown on Table b-1, contributions from loss of offsite power related initiating events increases significantly when 1B DG is out of service.

Table b-1; Contribution from Internal Initiating Events

	Base case		NOED Case (1B DG out of service)		Δ CDF		
Initiator	CDF	%	CDF	%	Δ CDF	%	Description
%LOSPS	5.55E-07	7.50%	3.11E-06	20.60%	2.55E-06	33.29%	SINGLE UNIT LOSP DUE TO PLANT CENTERED EVENT
%LOSPDW	5.79E-07	7.80%	2.76E-06	18.30%	2.18E-06	28.46%	DUAL UNIT LOSP DUE TO SEVERE WEATHER EVENT
%LOSPDP	5.86E-07	7.90%	2.20E-06	14.60%	1.62E-06	21.12%	DUAL UNIT LOSP DUE TO PLANT CENTERED EVENT
%LOSPDG	4.23E-07	5.70%	1.33E-06	8.80%	9.02E-07	11.78%	DUAL UNIT LOSP DUE TO GRID RELATED EVENT
%MLO	1.10E-06	14.80%	1.10E-06	7.30%	3.80E-09	0.05%	MEDIUM PIPE BREAK LOCA
%LOSSSW	6.20E-07	8.40%	6.20E-07	4.10%	0.00E+00	0.00%	LOSS OF ALL SERVICE WATER INITIATING EVENT LEADING TO LOSS OF CCW
%SI	4.66E-07	6.30%	5.84E-07	3.90%	1.17E-07	1.53%	INADVERTENT SAFETY INJECTION
%SSBO	3.31E-07	4.50%	3.83E-07	2.50%	5.18E-08	0.68%	STEAM LINE BREAK INITIATING EVENT DOWNSTREAM OF MSIVs
%GT	3.54E-07	4.80%	3.63E-07	2.40%	8.73E-09	0.11%	GENERAL TRANSIENT INITIATING EVENT
%FLOOD_ AB223SP2	2.53E-07	3.40%	2.54E-07	1.70%	3.20E-10	0.00%	SP2 FLOODING INITIATOR IN 121' PIPING PENETRATION ROOM
%LOSSACF	2.34E-07	3.20%	2.52E-07	1.70%	1.76E-08	0.23%	LOSS OF 4160V BUS F
%LOSSACG	2.34E-07	3.20%	2.34E-07	1.60%	0.00E+00	0.00%	LOSS OF 4160V BUS G
%SLO	2.01E-07	2.70%	2.05E-07	1.40%	3.87E-09	0.05%	SMALL PIPE BREAK LOCA
%FLOOD_ AB210FP	2.02E-07	2.70%	2.02E-07	1.30%	0.00E+00	0.00%	FP FLOODING INITIATOR IN CORRIDOR 210
%FLOOD_ AB228FP	1.68E-07	2.30%	1.68E-07	1.10%	0.00E+00	0.00%	FP FLOODING INITIATOR IN CORRIDOR 228
%LOSPG	1.27E-08	0.20%	1.61E-07	1.10%	1.48E-07	1.93%	LOSS OF OFFSITE POWER TO BUS G INITIATING EVENT
%FLOOD_ AB211FP	1.56E-07	2.10%	1.56E-07	1.00%	0.00E+00	0.00%	FP FLOODING INITIATOR IN CORRIDOR 211

Table b-2 below shows the top ten internal events PRA cutsets for the condition of DG 1B out of service. Except for the top five cutsets, the contribution is evenly distributed. Further review indicates that around 97% of the CDF increase results from Loss of Offsite Power (LOOP) when DG 1B is out of service.

Table b-2; Top Ten Internal Event PRA Cutsets

#	Cutset Prob	%	Event	Event Prob	Description
1	9.70E-07	6.43%	%LOSPS	1.20E-02	SINGLE UNIT LOSP DUE TO PLANT CENTERED EVENT
			#FL-SBO	1.00E+00	IE-FLAG-TRANSIENT WITH CONSEQUENTIAL LOSP
			1DGOPOPERDG1CH	3.32E-02	OPERATOR FAILS TO ALIGN DG 1C TO SUPPLY BUS 1F & SEQUENCE LOADS
			BDGGER43A501AX L	4.60E-02	DIESEL 1/2A FAILS TO RUN DUE TO RANDOM FAILURE
			COMB455	1.80E-03	HEP DEPENDENCY
			DGOPSTART2C--H	1.70E-02	OPERATOR FAILS TO START DIESEL GENERATOR 2C
			ORS_A_1------H	4.00E-03	OPERATOR FAILS TO RESTORE SYSTEMS FOLLOWING POWER RECOVERY
			SDS-ACTUATES	9.77E-01	RCP SHUT DOWN SEAL ACTUATES AND LIMITS RCP SEAL LEAKAGE TO 2 GPM OR LESS
2	7.94E-07	5.26%	%MLO	4.90E-04	MEDIUM PIPE BREAK LOCA
			OAR_B_1------H	1.62E-03	OPERATOR FAILS TO ESTABLISH HIGH HEAD ECCS RECIRC
3	2.41E-07	1.60%	%FLOOD_AB223SP2	4.08E-05	SP2 FLOODING INITIATOR IN 121' PIPING PENETRATION ROOM
			#FL-CPZR	1.00E+00	FLAG-IE-CONSEQUENTIAL PRESSURIZER LOCA
			COMB606	5.90E-03	HEP DEPENDENCY
			OAC_A_1------H	8.80E-03	OPERATOR FAILS TO COOLDOWN RCS VIA SECONDARY (MAX RATE,W/O HHI)
			OAT_B_1------H	3.91E-02	OPERATOR FAILS TERMINATE SI AND ESTABLISH CHARGING
4	2.16E-07	1.43%	%SSBO	9.82E-03	STEAM LINE BREAK INITIATING EVENT DOWNSTREAM OF MSIVs
			COMB612	2.20E-05	HEP DEPENDENCY
			OAR_B_1------H	1.62E-03	OPERATOR FAILS TO ESTABLISH HIGH HEAD ECCS RECIRC
			OAT_C_1------H	1.40E-02	OPERATOR FAILS TO TERMINATE SI AND ALIGN NORMAL CHARGING
5	1.67E-07	1.11%	%LOSSSW	1.00E+00	LOSS OF ALL SERVICE WATER INITIATING EVENT LEADING TO LOSS OF CCW

#	Cutset Prob	%	Event	Event Prob	Description
			#FL-RCPT	1.00E+00	IE FLAG-RCPT-CON. RCP SEAL RCP SEAL LOCA - GT WO LOSP
			1EAOP--------H	8.80E-02	OPERATOR FAILS TO ALIGN EMERGENCY AIR SYSTEM
			1SWMV507-I---R	8.62E-06	RUPTURE OF XCONN MOV 507 IN SW PUMP DISCHARGE HEADER
			COMB626	2.70E-02	HEP DEPENDENCY
			OIA_A_1------H	2.69E-02	OPERATOR FAILS TO ALIGN & START COMPRESSOR 2C ON UNIT 1
			PLGE40	7.33E-01	POWER GREATER THAN OR EQUAL TO 40% PRIOR TO EVENT
			SDS-ACTUATES	9.77E-01	RCP SHUT DOWN SEAL ACTUATES AND LIMITS RCP SEAL LEAKAGE TO 2 GPM OR LESS
6	1.21E-07	0.80%	%LOSPDP	2.93E-03	DUAL UNIT LOSP DUE TO PLANT CENTERED EVENT
			#FL-SBO	1.00E+00	IE-FLAG-TRANSIENT WITH CONSEQUENTIAL LOSP
			BDGGER43A501AX L	4.60E-02	DIESEL 1/2A FAILS TO RUN DUE TO RANDOM FAILURE
			COMB655	9.20E-04	HEP DEPENDENCY
			DGOPSTART2C--H	1.70E-02	OPERATOR FAILS TO START DIESEL GENERATOR 2C
			ORS_A_1------H	4.00E-03	OPERATOR FAILS TO RESTORE SYSTEMS FOLLOWING POWER RECOVERY
			SDS-ACTUATES	9.77E-01	RCP SHUT DOWN SEAL ACTUATES AND LIMITS RCP SEAL LEAKAGE TO 2 GPM OR LESS
7	1.03E-07	0.68%	%LOSSSW	1.00E+00	LOSS OF ALL SERVICE WATER INITIATING EVENT LEADING TO LOSS OF CCW
			#FL-RCPT	1.00E+00	IE FLAG-RCPT-CON. RCP SEAL RCP SEAL LOCA - GT WO LOSP
			1AFPT002-TR--X	1.67E-02	TDP P002 FAILS TO RUN DUE TO RANDOM FAULTS
			1SWMV507-I---R	8.62E-06	RUPTURE OF XCONN MOV 507 IN SW PUMP DISCHARGE HEADER
			PLGE40	7.33E-01	POWER GREATER THAN OR EQUAL TO 40% PRIOR TO EVENT
			SDS-ACTUATES	9.77E-01	RCP SHUT DOWN SEAL ACTUATES AND LIMITS RCP SEAL LEAKAGE TO 2 GPM OR LESS
8	9.83E-08	0.65%	%LOSPDG	2.38E-03	DUAL UNIT LOSP DUE TO GRID RELATED EVENT

#	Cutset Prob	%	Event	Event Prob	Description
			#FL-SBO	1.00E+00	IE-FLAG-TRANISIENT WITH CONSEQUENTIAL LOSP
			BDGGER43A501AX L	4.60E-02	DIESEL 1/2A FAILS TO RUN DUE TO RANDOM FAILURE
			COMB655	9.20E-04	HEP DEPENDENCY
			DGOPSTART2C--H	1.70E-02	OPERATOR FAILS TO START DIESEL GENERATOR 2C
			ORS_A_1------H	4.00E-03	OPERATOR FAILS TO RESTORE SYSTEMS FOLLOWING POWER RECOVERY
			SDS-ACTUATES	9.77E-01	RCP SHUT DOWN SEAL ACTUATES AND LIMITS RCP SEAL LEAKAGE TO 2 GPM OR LESS
9	9.83E-08	0.65%	%LOSPDW	2.38E-03	DUAL UNIT LOSP DUE TO SEVERE WEATHER EVENT
			#FL-SBO	1.00E+00	IE-FLAG-TRANISEINT WITH CONSEQUENTIAL LOSP
			BDGGER43A501AX L	4.60E-02	DIESEL 1/2A FAILS TO RUN DUE TO RANDOM FAILURE
			COMB655	9.20E-04	HEP DEPENDENCY
			DGOPSTART2C--H	1.70E-02	OPERATOR FAILS TO START DIESEL GENERATOR 2C
			ORS_A_1------H	4.00E-03	OPERATOR FAILS TO RESTORE SYSTEMS FOLLOWING POWER RECOVERY
			SDS-ACTUATES	9.77E-01	RCP SHUT DOWN SEAL ACTUATES AND LIMITS RCP SEAL LEAKAGE TO 2 GPM OR LESS
10	9.41E-08	0.62%	%LOSPDW	2.38E-03	DUAL UNIT LOSP DUE TO SEVERE WEATHER EVENT
			#FL-SBO	1.00E+00	IE-FLAG-TRANISEINT WITH CONSEQUENTIAL LOSP
			BDGGER43A501AX L	4.60E-02	DIESEL 1/2A FAILS TO RUN DUE TO RANDOM FAILURE
			DGOPSTART2C--H	1.70E-02	OPERATOR FAILS TO START DIESEL GENERATOR 2C
			R8	1.00E+00	FAILURE TO RECOVER OFFSITE POWER PRIOR TO CORE UNCOVERY - 8.80 HOURS
			SDS-ACTUATES	9.77E-01	RCP SHUT DOWN SEAL ACTUATES AND LIMITS RCP SEAL LEAKAGE TO 2 GPM OR LESS
			R81W	5.18E-02	LOOP RECOVERY

Fire PRA Results

Table b-3 presents a description of the top 20 significant risk scenarios with 1B DG out of service. For the scenarios below, the fire risk in the base model was already dominated by the 1B diesel generator unavailability. For the current situation represented by known unavailability of DG 1B, the CDF for each of these scenarios results in increases. Typically in these scenarios, the risk is dominated by offsite power and the plant diesel generators being unavailable from the combination of fire impacts and random failures.

Table b-3; Fire Scenarios Individually Representing >1% of the Calculated CDF

Scenario	Scenario Details	Base CDF	CDF with DG1B OOS
1-080G/E	This fire scenario has a calculated CDF contribution that represents 6.30% of the total for the plant when 1B DG is OOS. The scenario represents a fire initiated from Startup Aux. Transformer (SUT) 1A. This fire event causes a loss of offsite power to unit 1 since both SUTs are impacted by fire. The random failure of DG 1/2A comprises the top cutsets in this scenario.	1.87E-06	6.05E-06
1-080H/E	This fire scenario has a calculated CDF contribution that represents 6.30% of the total for the plant when 1B DG is OOS. The scenario represents a fire initiated from SUT 1B. This fire event causes a loss of offsite power to unit 1 since both SUTs are impacted by fire. The random failure of DG 1/2A comprises the top cutsets in this scenario.	1.94E-06	6.05E-06
0335/J3b	This fire scenario has a calculated CDF contribution that represents 3.3% of the total for the plant. The scenario represents a 4.16kV Bus 1F High Energy Arcing Fault (HEAF) event. The ensuing fire in the switchgear propagating into the overhead trays is assumed to grow rapidly and therefore there is no credit for any type of suppression for this scenario. There is a loss of off-site power in this scenario and along with other random failures in the scenario it leads to a station blackout.	2.68E-06	3.17E-06
1-041-ADJ/HGL	This fire has a calculated CDF contribution that represents 2.9% of the total for the plant. The scenario is related to a hot gas layer event which, the postulated fire fails every target within the PAU, not taking into consideration the layout of the room or the physical location of the targets. This fire area is the train B switchgear room, a fire in this area would cause loss of offsite power to unit 1.	9.16E-07	2.78E-06

Scenario	Scenario Details	Base CDF	CDF with DG1B OOS
1-088/F3	This fire scenario has a calculated CDF contribution that represents 2.8% of the total for the plant. The scenario represents a 4.16kV Bus 1E HEAF event. The ensuing fire in the switchgear propagating into the overhead trays is assumed to grow rapidly and therefore there is no credit for any type of suppression for this scenario. There is a loss of off-site power in this scenario and along with other failures in the scenario it leads to a secondary side break.	8.36E-07	2.70E-06
1-088/E3	This fire scenario has a calculated CDF contribution that represents 1.9% of the total for the plant. The scenario represents a 600V Switchgear 1Q HEAF event. The fire induced failures in this scenario include the SUTs 1A and 1B. Coupled with a random failure of the DGs, this scenario results in a Station Black Out (SBO).	5.78E-07	1.87E-06
1-TB-ADJ/TURB_FAIL	This fire scenario has a calculated CDF contribution that represents 1.8% of the total for the plant. This scenario is related to collapse of Turbine Building due to exposed structural steel in the Turbine Building under presence of large oil fire.	2.05E-07	1.70E-06
0343/I3	This fire scenario has a calculated CDF contribution that represents 1.8% of the total for the plant. The scenario represents a 4.16kV Bus 1B HEAF event. The ensuing fire in the switchgear propagating into the overhead trays is assumed to grow rapidly and therefore there is no credit for any type of suppression for this scenario. There is a loss of off-site power in this scenario and along with other failures in the scenario it leads to a secondary side break.	1.62E-06	1.70E-06
0335/J2h	This fire scenario has a calculated CDF contribution that represents 1.6% of the total for the plant. The scenario represents a non-severe fire at 4.16kV Bus 1F-DF15. This scenario causes a LOSP due to the loss of SUT 1B and the random failure of the operators to use SUT 1A to power the 4.16kV Bus 1G.	1.24E-06	1.58E-06
0233/I3b	This fire scenario has a calculated CDF contribution that represents 1.3% of the total for the plant. The scenario represents a 4.16kV Bus 1G HEAF event. The ensuing fire in the switchgear propagating into the overhead trays is assumed to grow rapidly and therefore there is no credit for any type of suppression for this scenario. The fire induced failures in this scenario include the SUTs 1A and 1B. Coupled with a random failure of the 1-2A DG this scenario results in an SBO.	3.41E-06	1.25E-06

Scenario	Scenario Details	Base CDF	CDF with DG1B OOS
%_IGF-0318D11	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The scenario represents a transient fire resulting in consequential Pressurizer LOCA in the Cable Spreading Room.	3.14E-07	1.20E-06
%_IGF-0318D12	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The scenario represents a transient fire resulting in consequential Pressurizer LOCA in the Cable Spreading Room.	3.14E-07	1.20E-06
%_IGF-0318D13	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The scenario represents a transient fire resulting in consequential Pressurizer LOCA in the Cable Spreading Room.	3.14E-07	1.20E-06
%_IGF-0318D7	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The scenario represents a transient fire resulting in consequential Pressurizer LOCA in the Cable Spreading Room.	3.14E-07	1.20E-06
%_IGF-0318D10	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. There is a loss of off-site power in this scenario and along with other failures in the scenario it leads to a PORV opening and consequential Pressurizer LOCA.	4.10E-07	1.18E-06
%_IGF-0318D3	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The specific event represents a transient fire resulting in loss of offsite power to unit 1. Due to the loss of off-site power and the diesel generators are relied on to provide power to the Class 1E Buses. The random failures of these generators comprise the top cutsets in this scenario.	1.46E-07	1.18E-06
%_IGF-0318D4	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The specific event represents a transient fire resulting in loss of offsite power to unit 1. Due to the loss of off-site power and the diesel generators are relied on to provide power to the Class 1E Buses. The random failures of these generators comprise the top cutsets in this scenario.	1.96E-07	1.18E-06

Scenario	Scenario Details	Base CDF	CDF with DG1B OOS
%_IGF-0318D8	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The specific event represents a transient fire resulting in loss of offsite power to unit 1. Due to the loss of off-site power and the diesel generators are relied on to provide power to the Class 1E Buses. The random failures of these generators comprise the top cutsets in this scenario. Along with other failures in the scenario it leads to a consequential Pressurizer LOCA.	1.97E-07	1.18E-06
%_IGF-0318D9	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The specific event represents a transient fire resulting in loss of offsite power to unit 1. Due to the loss of off-site power and the diesel generators are relied on to provide power to the Class 1E Buses. The random failures of these generators comprise the top cutsets in this scenario. Along with other failures in the scenario it leads to a PORV opening or consequential Pressurizer LOCA.	4.10E-07	1.18E-06
%_IGF-0343F1	This fire scenario has a calculated CDF contribution that represents 1.2% of the total for the plant. The scenario represents a severe fire at 4.16kV Bus 1F. This scenario causes a loss of off-site power due to the damages of SUTs.	1.45E-07	1.11E-06

c. **Explain compensatory measures that will be taken to reduce the risk associated with the specified configuration. Compensatory measures to reduce plant vulnerabilities should focus on both event mitigation and initiating event likelihood. The objectives are to:**

   i. **Reduce the likelihood of initiating events;**

   ii. **Reduce the likelihood of unavailability of trains redundant to the equipment that is out-of-service during the period of enforcement discretion;**

   iii. **Increase the likelihood of successful operator recovery actions in response to initiating events.**

Based on the assessment of the contributors to the risk increase and a review of the postulated plant features credited in the Fire PRA, the following compensatory measures will be implemented. These measures provide reasonable assurance that the assumptions in the risk model are maintained, reduce the likelihood of most significant initiating events (loss of offsite power) given the plant configuration during the enforcement discretion period. Additionally, these measures reduce failure probability of the components, operator actions, and features credited to mitigate the consequences of the postulated event. As outlined in section b, and as expected, the majority of the risk increase from the unavailability of the 1B DG is due to the increase from the loss of offsite power initiating event. The increase in the contribution of this initiating event is significantly reduced by implementing the following compensatory measures:

<u>Reduction in likelihood of initiating events</u>

The following compensatory measures will be implemented to reduce the likelihood of random loss of offsite power initiating event:

1. Operations will monitor weather conditions to assess potential impacts on plant conditions due to adverse weather conditions (see 4g).

2. Maintenance and surveillance activities which could increase the risk of a main turbine or reactor trip will be avoided. It is judged that, given the current high power demand, if Farley were to suddenly and unexpectedly come off line, there is a non-negligible probability that the grid stability will be challenged, resulting in a loss of offsite power to both units.

3. Work on any activity that could impact loss of offsite power availability will be avoided. For example, all switchyard related activities with potential to result in the loss of offsite power shall be postponed. This reduces the frequency of the random loss of offsite power initiating event. Additionally, FNP has procedure NMP-GM-021, "Switchyard Access and Maintenance Controls," to control work in the switchyard.

The following compensatory measures will be implemented to reduce the likelihood of fire-induced loss of offsite power initiating event:

4. Increased administrative control will be exercised for any proposed hot work in the vicinity of protected equipment and in the impacted fire zones 0335/0343 (Train A Switchgear Room), 0318 (Cable Spreading Room), 1-080G (Start-up Transformer

1A), 1-080H (Start-up Transformer 1B), 1-085 (Turbine Building General Area) and 1-088 (Turbine Building Switchgear Room).

5. Transient combustible loading in the areas in the fire zone outlined in item 7 will be reviewed and any unnecessary transient combustibles will be removed.

Reduction in the unavailability of redundant system and components

6. The following equipment will be protected in accordance with the procedure NMP-OS-010, "Protected Train/Division and Protected Equipment Program," during the discretionary period. The Protected Equipment Program requirements include 1) posting of protected equipment with signs and barriers to prevent inadvertent operation; 2) no routine work activities on protected equipment; and 3) Shift Manager approval for any emergent work involving protected equipment.

    - Emergency Diesel Generators rooms for 1C, 1-2A, and 2C.
    - Emergency Diesel Generators Mode Selector Switch for 1C and 1-2A DG on the Emergency Power Board in the control room
    - Unit 1 A train DC Switchgear Room
    - Unit 1 A train Battery Chargers
    - 1A Auxiliary Builiding Battery Room
    - Unit 1 A and B Train 4160V Emergency Switchgear Rooms
    - Unit 1 A train Motor Driven Auxiliary Feedwater Pump
    - Unit 1 Turbine Driven Auxiliary Feedwater Pump
    - Unit 1 A train Residual Heat Removal pump
    - Unit 1 A train Charging Pump.
    - Unit 1 A train Service Water Pumps
    - Unit 1 A train Component Cooling Water Pump
    - Diesel Driven Fire Pump
    - Unit 1 Main Transformers
    - Unit 1 Start-Up Transformer

Reduction in the fire-induced damage to the mitigating systems

7. Roving fire watches will reduce the frequency of damaging fires.

    - Zone 0335/0343: A Train Switchgear Room - Fire watch in these zones, specifically focused on preventing the fire originating from Bus 1F for early suppression of the fire.

    - Zone 1-080G/1-080H: Start-up Transformers - Fire watch for early actuation of fire suppression to prevent the damage to overhead cables.

    - Zone 1-085: Turbine Building General Area - Fire watch at the 125V DC Distribution Cabinet 1J.

8. No maintenance will be planned on fire detection or fire suppression equipment that will impact fire detection or fire suppression equipment in the impacted fire zones listed in item 4.

<u>Increase in likelihood of successful operator actions:</u>

9. The plant Operations crew and Maintenance staff will be briefed on these risk management measures at the start of each shift.

10. Provide a designated operator to use the DG 2C to power Bus 1G via Bus 1J. This will reduce the risk for fire-induced and random events in the event of a loss of power to 1G bus

11. Provide a designated operator to align the SUT 1A to the 1G bus in the event of a fire-induced loss of offsite power.

12. Each shift operator will review actions per procedure to terminate spurious SI signal and establish charging following a fire originating in Train A Switchgear room (fire zone 0335/0343).

13. Each shift operator will review actions per procedure for DG 1C connection to the Bus 1F via Bus 1H in case of a fire originating in the Startup Transformers fire zone (Zone 1-080G/1-080H:) and Turbine Building General Area and Switchgear Room (1-085/1-088)

Compensatory Measures for Farley Fire PRA Model

The Farley Fire PRA (FPRA) model has been peer reviewed to RG 1.200, Revision 2 and facts and observations (F&O) dispositioned. However, the FPRA model was developed to support Plant Farley's transition to NFPA-805 and does not exactly represent the current as-built and as-operated Farley plant. Specifically, the FPRA model credits certain modifications not yet installed in the plant. For this one-time NOED, SNC has elected to define compensatory measures which offset plant risk associated with the future modifications for NFPA-805. Although these compensatory actions do not fully compensate for the NFPA-805-driven plant modifications, it is judged that for the discretion period and given the heightened awareness of the site, they do provide adequate substitute for the committed plant modifications. For example, it is judged that a continuous fire watch compensatory measure is an adequate temporary substitute for the incipient detectors in electrical cabinet or sealing of electrical cabinets. The future modifications provide an incipient fire detection system in the main control room, cable spreading room, and hot shutdown panel room, and provide cable protection to prevent functional failure of certain components due to a fire event.

1. The following [CWP1] fire watches will reduce the frequency and severity of damaging fires and offset risk for future incipient fire detection equipment.

    - Fire Area 1-040: Cable Spreading Room – Continuous [CWP1]
    - Fire Area 1-012: Hot Shutdown Panel Room – Continuous
    - Fire Area 044: Main Control Room – Continuous Roving

2. The following fire watches will reduce the frequency and severity of damaging fires related to cable protection. Continuous roving watches will inspect for transient combustibles and unnecessary transient combustibles will be removed.

    - Fire Area 1-018: DC Equipment Room – Continuous Roving
    - Fire Area 1-005: 1A Charging Pump Room – Continuous Roving
    - Fire Area 1-021: Train B Switchgear Room – Continuous Roving
    - Fire Area 057: 2C EDG – Continuous Roving
    - Fire Area 056B: EDG Building Switchgear - Continuous
    - Fire Area 061: 1/2A EDG – Continuous Roving
    - Fire Area 1-041: Train A Switchgear Room – Continuous Roving
    - Fire Area 044: Main Control Room – Continuous Roving [CWP1]

3. The following fire areas should have no hot work in the area during enforcement discretion period to ensure no transient combustibles or ignition sources; the areas will also be inspected during the fire watch.

    - Fire Area 1-008: Aux Building Cable Chase – Continuous Roving
    - Fire Area 1-013: Aux Building Cable Chase – Continuous Roving

4. The following fire watches will reduce the probability of MCC fires propagating to overhead trays.

    - Fire Area 1-004: Auxiliary Building – Roving
    - Fire Area 1-034: Train B Electrical Pen Room – Continuous Roving
    - Fire Area 1-035: Train A Electrical Pen Room – Continuous Roving

d. Discuss how the proposed compensatory measures are accounted for in the PRA. These modeled compensatory measures should be correlated, as applicable, to the dominant PRA sequences identified in item b. above. In addition, other measures not directly related to the equipment out-of-service may also be implemented to reduce overall plant risk and, as such, should be explained. Compensatory measures that cannot be modeled in the PRA should be assessed qualitatively.

Ten of the first thirteen compensatory measures listed in part c list compensatory measures not directly credited in the PRA calculation of ICCDP and ICLERP. (Items 10, 11 and 13 are credited). The uncredited actions are intended as actions to increase operator awareness of plant conditions, to reduce the likelihood of losing redundant trains and to reduce the likelihood, and consequences, of initiating events. Action 10 will reduce the failure probability of an operator manual action to align Start-up transformer 1A to the Bus 1G emergency 4 kV bus for a loss of offsite power.

The last four measures provided in part c. above are being put in place to simulate, as closely as possible, the future NFPA 805 modifications. With these compensatory measures in place, the current Farley Fire PRA may be used for evaluating the risk for the enforcement discretion period without significant deviations from the actual risk.

e. Discuss the extent of condition of the failed or unavailable component(s) to other trains/divisions of equipment and what adjustments, if any, to the related PRA common cause factors have been made to account for potential increases in their

failure probabilities. The method used to determine the extent of condition should be discussed. It is recognized that a formal root cause or apparent cause is not required given the limited time available in determining acceptability of a proposed NOED. However, a discussion of the likely cause should be provided with an associated discussion of the potential for common cause failure.

The thermostatic bypass valve did not function properly which prevented adequate cooling of the intercooler system. Surveillance Requirement (SR) 3.8.1.6 was completed to ensure operability of 1-2A DG and comply with Required Action B.3.2 on July 23, 2012. The 1-2A DG 24-hour run surveillance was previously completed satisfactorily on July 9, 2012. Review of the recent test data for the 1-2A DG and the 2B DG has been completed and it has been determined that the deficiency does not extend to those DGs. All surveillance and testing requirements are current for 1-2A, 2B, and 1C DGs, therefore, these emergency power sources will remain OPERABLE during the requested LCO extension and the station blackout diesel 2C will remain available.

f. Discuss external event risk for the specified plant configuration. An example of external event risk is a situation where a reactor core isolation cooling (RCIC) pump has failed and a review of the licensee's Individual Plant Examination of External Events or full-scope PRA model identifies that the RCIC pump is used to mitigate certain fire scenarios. Action may be taken to reduce fire ignition frequency in the affected areas or reduce human error associated with time-critical operator actions in response to such scenarios.

An estimation of the fire risk impacts is provided in Section a. above.

The seismic risk increase due to the 1B DG unavailability is judged to be negligible based on the following:

1. Due to a low seismic hazard, FNP is categorized as a reduced scope plant. Therefore, the baseline seismic risk is judged to be minimal.

2. The FNP IPEEE study did not identify any seismic vulnerabilities.

3. In general, seismic events are considered to result in non-recoverable loss of off-site power events. Therefore, it is judged that the unavailability of 1B diesel generator may have an impact on the seismic-induced loss of offsite power. Based on the following evaluation it is found that this potential increase in risk is bounded by the risk-increase due to a traditional grid-induced loss of offsite power or a fire-induced loss of offsite power:

   - For a low severity seismic event, the diesels and other safety related components are not likely to fail due to the seismic event (i.e., safety related components are designed to a higher standard than offsite power related components). Therefore, the consequences of a low severity seismic event is judged to be the same as a random non-recoverable fire-induced loss of offsite power event. Per the IPEEE, Farley is categorized as a low seismic hazard. Therefore, frequency of seismic-induced loss of offsite power is judged to be lower than the frequency of the traditional or fire-induced loss of offsite power.

- For a high severity seismic event, based on the current state-of-the-art seismic practice where full correlation for redundant components are assumed, a severe seismic event would result in loss of all DGs. As a result, the unavailability of one diesel is not risk significant.

In addition to internal fires and seismic events, the FNP IPEEE analysis of external hazards, resulting from high winds, external floods, and transportation and nearby facilities accidents was accomplished by using a progressive screening approach described in NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities". No vulnerabilities were identified for FNP as a result of these evaluations. In addition, no other plant-unique external event was identified that poses any significant threat of severe accident within the context of the screening approach for "High Winds, Floods, and Others" provided by NUREG-1407.

It should also be noted, as discussed in part g below, the weather forecast for the period of the enforcement discretion does not call for any severe weather events which would challenge the on-site emergency power sources and distribution systems.

g. Discuss forecasted weather conditions for the NOED period and any plant vulnerabilities related to weather conditions.

No severe weather conditions, as defined in normal operating procedures, are forecast for the enforcement discretion period. Probable weather conditions during the enforcement discretion period are not expected to expose the plant to any vulnerability. However, in the event that the forecast changes, the impact of severe weather on online plant risk can be addressed under the risk assessment software (EOOS) and is already part of online risk management.

5. Provide the justification for the duration of the non-compliance.

The duration of the non-compliance is proposed to be the shorter of either the time to return the 1B DG to service or the 66-hour extension from 21:52 on July 26, 2012.

SNC has completed inspections and repair work for the 1B DG and the critical path is lube oil flush. However, the diesel generator reassembly and maintenance testing involves several major activities. Steps to return the diesel to operable status include:

1.	Lube oil flush completed	7/26
2.	Jacket water system returned to service	7/26
3.	Lube oil system returned to service	7/26
4.	Start first maintenance run (5-minute, 10-minute, 30-minute, 6-hour run with special fuel additive, 20-hour run without fuel additive, 5-hour DG load run, 4-hour post maintenance run)	7/26
5.	Complete maintenance runs	7/28
6.	Commence Operability surveillance test	7/28
7.	Exit LCO	7/28

Note: 1B DG will be considered available prior to starting the surveillance test.

These activities will be worked around-the-clock until 1B DG Operability is restored. A small amount of contingency (approximately 18 hours) is provided to prevent time pressure from impacting productivity and quality of workmanship.

6. Provide the condition and operational status of the plant (including safety-related equipment out-of-service or otherwise inoperable).

As of July 26, 2012, Unit 1 is at 100% power with no major risk-significant equipment out of service. In the event of an emergent condition, a program is in place to ensure that the risk impact of out of service equipment is evaluated prior to performing any maintenance activity.

7. Provide the status and potential challenges to off-site and on-site power sources.

Currently the 1B DG is the only equipment out of service for the on-site AC power distribution system. With the 1B DG out of service, the 1G DG is available to the B train 1E 4160V bus normally supported by the 1B DG as a source of power for LOSP loads. There are no activities scheduled in the switchyard that will adversely affect the risk during the 1B DG extension period. The current status of the grid is normal and is projected to remain normal for the duration of the NOED request.

Severe weather is not predicted for the extent of the NOED based on the National Weather Service forecast for Dothan, Alabama.

8. Provide the basis for the licensee's conclusion that the non-compliance will not be of potential detriment to the public health and safety.

a. The proposed enforcement discretion does not involve a significant increase in the probability or consequences of an accident previously evaluated. Specifically, the proposed enforcement discretion does not alter any plant equipment or operating practices in such a manner that the probability of an accident is increased. Further, the proposed enforcement discretion will not alter assumptions relative to the mitigation of an accident or transient event. As discussed in the response to Question number 4 above, there is not a significant increase in core damage probability resulting from the proposed Enforcement Discretion. Therefore, the proposed enforcement discretion does not involve a significant increase in the probability or consequences of an accident previously evaluated.

b. The proposed enforcement discretion does not create the possibility of a new or different kind of accident from any accident previously evaluated. Specifically, the proposed enforcement discretion does not involve any physical alteration of the plant or a change in the methods governing normal plant operation. Therefore, the proposed enforcement discretion does not create the possibility of a new or different kind of accident from any accident previously evaluated.

c. The proposed enforcement discretion does not involve a significant reduction in a margin of safety. Specifically, based on the operability of the remaining Unit 1 diesel generator and offsite power sources, the accident analysis assumptions continue to be met with the enactment of the proposed enforcement discretion. The system's design and operation are not affected by the proposed enforcement discretion. The safety analysis acceptance criteria are not altered by the proposed changes. Finally, the proposed compensatory measures will provide further assurance that no significant reduction in safety margin will occur.

Based on the above, SNC concludes that the proposed enforcement discretion will not be of potential detriment to the public health and safety.

9. Provide the basis for the licensee's conclusion that the non-compliance will not involve adverse consequences to the environment

In considering the environmental impacts, it is noted that:

(i) There is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite. The proposed enforcement discretion does not involve the installation of any new equipment or the modification of any equipment that may affect the types or amounts of effluents that may be released offsite. Therefore, there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite.

(ii) There is no significant increase in individual or cumulative occupation radiation exposure. The proposed change does not affect plant radiation levels. Therefore, there is no significant increase in individual or cumulative occupational radiation exposure.

SNC has evaluated the proposed enforcement discretion and has determined that in accordance with 10 CFR 51.21, the enforcement discretion is excluded from the requirement of an environmental impact statement.

10. Provide a statement that the request has been approved by the facility organization that normally reviews safety issues (plant On-Site Review Committee, or its equivalent).

The request for the discretionary enforcement and its supporting justification has been reviewed by the FNP Plant Review Board (PRB) and they have concurred with the need and justification and have approved this request.

11. The NOED must specifically address which of the NOED criteria for appropriate plant conditions specified in Section B (reference Inspection Manual Part 9900 NOED) is satisfied and how it is satisfied.

This NOED addresses the criteria in Section B.1.a, that for a plant in power operation, an NOED is intended to avoid unnecessary transients as a result of compliance with the license condition and, thus minimize potential safety consequences and operational risks.

12. Unless otherwise agreed as discussed in Section B, a commitment is required from the licensee that the written NOED request will be submitted within two working days and the follow-up amendment will be submitted within four working days of verbally granting the NOED.

A written request for this enforcement discretion will be submitted to the NRC by July 30, 2012. During the verbal request for a NOED, it was agreed that a follow-up amendment is not needed.

13. In addition to items 1-12 above, for severe weather NOED request the licensee must provide the following information.

a. The name, organization and telephone number of the official in the government or independent entity who made the emergency situation determination. If deemed necessary, the staff may contact the appropriate official to independently verify the information provided by the licensee prior to making an NOED determination.

b. Details of the basis and nature of the emergency situation including, but not limited to, its effect on:

i. on-site and off-site emergency preparedness;

ii. plant and site ingress and egress;

iii. off-site and on-site power sources;

iv. grid stability; and

v. actions taken to avert and/or alleviate the emergency situation (e.g., coordinating with other utilities and the load dispatcher organization for buying additional power or for cycling load, or shedding interruptible industrial or non-emergency loads).

c. Potential consequences of compliance with existing license requirements (e.g., plant trip, controlled shutdown).

d. The impact of the emergency situation on plant safety including the capability of the ultimate heat sink.

e. Potential adverse effects on public health and safety from enforcing compliance with specific license requirements during the emergency situation.

This proposed enforcement discretion is not in regard to severe weather or nature phenomena-related emergencies.