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

March 7, 2013

Mr. Vito A. Kaminskas
Site Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
Mail Stop A-PY-A290
P.O. Box 97, 10 Center Road
Perry, OH 44081-0097

SUBJECT: PERRY NUCLEAR POWER PLANT, UNIT NO. 1 - ISSUANCE OF AMENDMENT RE: MODIFY TECHNICAL SPECIFICATION 3.8.1, "AC SOURCES – OPERATING," TO REMOVE MODE RESTRICTIONS ON CERTAIN DIVISION 3 SURVIELLANCE REQUIREMENTS (TAC NO. ME9006)

Dear Mr. Kaminskas:

The U.S. Nuclear Regulatory Commission (NRC, the Commission) has issued the enclosed Amendment No. 162 to Facility Operating License No. NPF-58 for the Perry Nuclear Power Plant, Unit No. 1. This amendment revises the Technical Specifications (TSs) in response to your application dated July 3, 2012, supplemented by letter dated January 7, 2013.

This amendment revises TS 3.8.1, "AC [alternating current] Sources - Operating," to modify nine surveillance requirements (SRs) by excluding Division 3 from current mode restrictions, thus allowing performance of the subject SRs in any mode of plant operation.

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

Sincerely,

Michael Mahoney, Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-440

Enclosures:
1. Amendment No. 162 to NPF-58
2. Safety Evaluation

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FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

OHIO EDISON COMPANY

DOCKET NO. 50-440

PERRY NUCLEAR POWER PLANT, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 162
License No. NPF-58

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

   A. The application for license filed by FirstEnergy Nuclear Operating Company, et al., (the licensee, FENOC) dated July 3, 2012, as supplemented by letter dated January 7, 2013, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Facility Operating License No. NPF-58 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 162 are hereby incorporated into this license. FENOC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of its issuance and shall be implemented within 30 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Jeremy S. Bowen, Chief
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications and Facility Operating License

Date of Issuance: March 7, 2013

ATTACHMENT TO LICENSE AMENDMENT NO. 162

FACILITY OPERATING LICENSE NO. NPF-58

DOCKET NO. 50-440

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

Remove	Insert
License NPF-58	License NPF-58
Page 4	Page 4
TSs	TSs
3.8-1	3.8-1
3.8-2	3.8-2
3.8-7	3.8-7
3.8-8	3.8-8
3.8-9	3.8-9
3.8-10	3.8-10
3.8-12	3.8-12
3.8-13	3.8-13
3.8-14	3.8-14

renewal. Such sale and leaseback transactions are subject to the representations and conditions set forth in the above mentioned application of January 23, 1987, as supplemented on March 3, 1987, as well as the letter of the Director of the Office of Nuclear Reactor Regulation dated March 16, 1987, consenting to such transactions. Specifically, a lessor and anyone else who may acquire an interest under these transactions are prohibited from exercising directly or indirectly any control over the licenses of PNPP Unit 1. For purposes of this condition the limitations of 10 CFR 50.81, as now in effect and as may be subsequently amended, are fully applicable to the lessor and any successor in interest to that lessor as long as the license for PNPP Unit 1 remains in effect; these financial transactions shall have no effect on the license for the Perry Nuclear facility throughout the term of the license.

(b) Further, the licensees are also required to notify the NRC in writing prior to any change in: (i) the terms or conditions of any lease agreements executed as part of these transactions; (ii) the PNPP Operating Agreement; (iii) the existing property insurance coverage for PNPP Unit 1; and (iv) any action by a lessor or others that may have an adverse effect on the safe operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now and hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

FENOC is authorized to operate the facility at reactor core power levels not in excess of 3758 megawatts thermal (100% power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 162, are hereby incorporated into the license. FENOC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Antitrust Conditions

a. FirstEnergy Nuclear Generation Corp. and Ohio Edison Company

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System; and

b. Three diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

----------------------------NOTE----------------------------
Division 3 AC electrical power sources are not required to be OPERABLE when High Pressure Core Spray System is inoperable.

ACTIONS

------------------------------------NOTE------------------------------------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit. AND	1 hour AND Once per 8 hours thereafter (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 Restore required offsite circuit to OPERABLE status.	72 hours AND 24 hours from discovery of two divisions with no offsite power AND 17 days from discovery of failure to meet LCO
B. One required DG inoperable.	B.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s). AND	1 hour AND Once per 8 hours thereafter
	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable. AND	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
		(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	-------------------NOTE------------------- All DG starts may be preceded by an engine prelube period. -- Verify each DG starts from standby conditions and achieves: a. In ≤ 10 seconds for Division 1 and 2, and ≤ 13 seconds for Division 3, voltage ≥ 3900 V and frequency ≥ 58.8 Hz; and b. Steady state voltage ≥ 3900 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	184 days
SR 3.8.1.8	---------------NOTE----------------------- This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. -- Verify manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	-----------------NOTES-------------------- 1. This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. 2. If performed with DG synchronized with offsite power, it shall be performed at a power factor ≤ 0.9. --- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load. Following load rejection, engine speed is maintained less than nominal plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 15% above nominal, whichever is less.	24 months
SR 3.8.1.10	-----------------NOTE--------------------- This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. --- Verify each DG operating at a power factor ≤ 0.9 does not trip and voltage is maintained ≤ 4784 V for Division 1 and 2 DGs and ≤ 5000 V for Division 3 DG during and following a load rejection of a load ≥ 5600 kW for Division 1 and 2 DGs and ≥ 2600 kW for Division 3 DG.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. -- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds for Division 1 and 2 DGs and ≤ 13 seconds for Division 3, 2. energizes auto-connected loads for Divisions 1 and 2, 3. maintains steady state voltage ≥ 3900 V and ≤ 4400 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected loads for ≥ 5 minutes.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. --	
	Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each DG auto-starts from standby condition and: a. In ≤ 10 seconds for Division 1 and 2, and ≤ 13 seconds for Division 3, after auto-start and during tests, achieves voltage ≥ 3900 V and frequency ≥ 58.8 Hz; and b. Achieves steady state voltage ≥ 3900 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	24 months
SR 3.8.1.13	-----------------NOTE----------------- This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. --	
	Verify each DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator differential current	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.15	-------------------NOTES------------------- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 1 hour loaded ≥ 5600 kW and ≤ 7000 kW for Division 1 and 2 DGs, and ≥ 2600 kW for Division 3 DG. Momentary transients outside of the load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. --- Verify each DG starts and achieves: a. In ≤ 10 seconds for Division 1 and 2, and ≤ 13 seconds for Division 3, voltage ≥ 3900 V and frequency ≥ 58.8 Hz; and b. Steady state voltage ≥ 3900 V and ≤ 4400 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	24 months
SR 3.8.1.16	-------------------NOTE------------------- This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. --- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	------------------NOTE------------------ This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. -- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency loads from offsite power.	24 months
SR 3.8.1.18	------------------NOTE------------------ This Surveillance shall not be performed in MODE 1, 2, or 3. However, credit may be taken for unplanned events that satisfy this SR. -- Verify for Division 1 and 2 DGs, the sequence time is within ± 10% of design for each load sequence timer.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.19	-------------------NOTES------------------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3). However, credit may be taken for unplanned events that satisfy this SR. --	
	Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds for Divisions 1 and 2 and ≤ 13 seconds for Division 3, 2. energizes auto-connected emergency loads (for Division 3, verify energization in ≤ 13 seconds), 3. achieves steady state voltage ≥ 3900 V and ≤ 4400 V, 4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	24 months

(continued)

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 162 TO FACILITY OPERATING LICENSE NO. NPF-58

FIRSTENERGY NUCLEAR OPERATING COMPANY

FIRSTENERGY NUCLEAR GENERATION CORP.

OHIO EDISON COMPANY

PERRY NUCLEAR POWER PLANT, UNIT NO. 1

DOCKET NO. 50-440

1.0 INTRODUCTION

By letter to the U.S. Nuclear Regulatory Commission (NRC, the Commission) dated July 3, 2012, as supplemented by letter dated January 7, 2013, (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML12188A001 and ML13007A470, respectively), FirstEnergy Nuclear Operating Company (FENOC, the licensee), requested an amendment to Facility Operating License Number NPF-58 for the Perry Nuclear Power Plant (PNPP), Unit No. 1.
The proposed license amendment request (LAR) would modify Technical Specification (TS) Section 3.8.1 "AC [alternating current] Sources – Operating," to revise certain Division 3 Surveillance Requirements (SRs). The Division 3 AC sources are separate sources of onsite and offsite power dedicated to supporting the High Pressure Core Spray (HPCS) system. SRs 3.8.1.8, 3.8.1.9, 3.8.1.10, and 3.8.1.12 are currently prohibited from being performed in Mode 1 or 2. In addition, SRs 3.8.1.11, 3.8.1.13, 3.8.1.16, 3.8.1.17, and 3.8.1.19, are currently prohibited from being performed in Mode 1, 2, or 3.

The proposed amendment would remove these mode restrictions and allow the subject SRs to be performed in any operating mode for the Division 3 HPCS AC sources only. The mode restrictions will remain applicable to Divisions 1 and 2.

The licensee stated that the reason for the proposed amendment is to provide greater flexibility in scheduling by allowing certain Division 3 surveillance tests to be performed during non-outage periods. Having a fully tested and available Division 3 emergency diesel generator (DG) for the duration of a refueling outage will reduce the number of system re-alignments and associated operator workload during the outage. Additionally, performing these Division 3 activities online increases the Division 3 DG and HPCS system availability during refueling outages and allows the Division 3 surveillance testing to be conducted when both Division 1 and 2 AC sources are required to be operable.

The LAR also proposes to delete the expired TS 3.8.1 provisions related to the delayed access circuit that was used in place of the circuit associated with the Unit 1 startup transformer through December 12, 2011. The licensee stated that removal of the provisions is included in this LAR for processing convenience only and does not affect the proposed amendment to remove the mode restrictions related to the Division 3 SRs.

The January 7, 2013, supplement contained clarifying information and did not change the NRC staff's initial proposed finding of no significant hazards consideration.

2.0 REGULATORY REQUIREMENTS

The regulatory requirements and guidance in which the NRC staff applied in its review of the amendment included:

Part 50, of Title 10 of the *Code of Federal Regulations* (10 CFR), Section 50.36(c), requires that TSs include items in five specific categories related to station operation. These categories are: (1) safety limits, limiting safety system settings, and limiting control settings, (2) limiting conditions for operations) (LCOs), (3) SRs, (4) design features, and (5) administrative controls.

10 CFR, Appendix A of Part 50, General Design Criterion (GDC) 17, "Electric Power Systems," in part, states, "An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety... The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure...."

GDC 18, "Inspection and testing of electric power systems," in part, states, "Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the conditions of their components."

Regulatory Guide 1.9, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plant," provides guidance for DG testing.

3.0 TECHNICAL EVALUATION

As described in Section 8.3 of the updated final safety analysis report (UFSAR), the Class 1E power system at PNPP supplies power to Division 1, 2, and 3 load groups, with each division powered by an independent Class 1E 4,160 volt (V) emergency bus. Each emergency bus has a preferred and an alternate offsite power source. Each emergency bus also has a dedicated onsite standby DG and two levels of undervoltage protection. If offsite power is insufficient or unavailable, emergency buses disconnect from the offsite source and independently connect to their respective onsite DG power source. The Division 3 DG supplies power to the HPCS pump motor and associated auxiliaries. Upon receipt of a loss-of-coolant accident (LOCA) signal (reactor vessel level 2 or high drywell pressure) or upon detection of HPCS bus undervoltage or degraded voltage, the Division 3 DG starts automatically and is capable of quickly restoring power to the HPCS pump motor in the event of a loss of offsite power (LOOP).

With the Division 3 DG running and paralleled with the grid during the surveillance test, if grid voltage started to degrade and was not identified, the DG's voltage regulator would increase field current in an effort to raise terminal voltage, until the regulator reached its limit. This DG voltage regulator limit is set such that the DG would continue to operate normally with the voltage regulator at its maximum output. The frequency would remain within limits and there would be no significant change in the loading on the DG. If grid voltage continued to degrade, protective relaying would initiate separation of the main generator and the Division 3 emergency bus from the degraded grid. This condition would have no adverse impact on the Division 3 DG or its associated loads. Since the conditions necessary for PNPP to enter into a degraded voltage condition on the 4,160 V emergency buses in any operational configuration would be severe, and outside of their specified operating band, the licensee stated that they would terminate all TS 3.8.1 AC source testing.

A significant overload of the Division 3 DG could result if operating in parallel with an offsite source that experiences a loss of power. Multiple line-ups, initial loading, and the number of potential LOOP scenarios make it difficult to analyze for each discrete possibility. However, there are only two potential outcomes of these various scenarios: (1) the diesel is loaded within its capability, and (2) the diesel is loaded beyond its capability. First, if the Division 3 DG is loaded within its capability, it will continue to operate normally with no adverse consequences. Secondly, significant overloading beyond the Division 3 DG capability would begin to stall the DG. At this point, multiple protective relay actuation sequences would begin. When loaded beyond capability, the DG would begin to stall within seconds. DG frequency would decay first, followed by voltage, and a protective relay would actuate and isolate the Division 3 DG from the offsite source.

Although the Division 3 DG is designed to withstand a full-load rejection without an overspeed, it is conservative to assume an overspeed lockout would occur. No damage is expected to occur to the Division 3 DG in this scenario. Both of the above potential outcomes resulting from a LOOP concurrent with the Division 3 DG paralleled to an offsite source are recoverable with no damage to the DG. These scenarios are not unique to the testing that is the subject of this request for licensing action, and they have been previously analyzed and found to be acceptable. The overload conditions described above would not occur if a concurrent LOCA signal is present. LOCA control logic automatically trips the DG output breaker when the DG is paralleled with an offsite source. The Division 3 DG will remain in a ready-to-load condition.

PNPP TSs impose requirements and restrictions on the amount of equipment allowed out of service at any given time. Specifically, TS 3.8.1 requires identification of inoperable required features, supported by the inoperable DG, that are redundant. Additionally, the program required by TS Section 5.5.10, "Safety Function Determination Program (SFDP)," ensures that a loss-of-safety function is detected and appropriate actions taken. In summary, even if a Division 3 power source were adversely impacted while testing in the proposed manner, the impact will be limited to Division 3 AC sources. Plant safe shutdown capability will continue to be ensured by protected Division 1 and 2 AC sources.

The HPCS system has a full-flow suction line and a return line to both the suppression pool and the condensate storage tank (CST), and an automatically actuated minimum flow line to the suppression pool. These features allow testing of the system online without discharging into the reactor vessel, while providing protection of the pump from overheating. The HPCS system configuration is such that testing can be performed without impacting other divisional safety systems or the reactor core isolation cooling (RCIC) system. Additionally, as described in the UFSAR, Section 6.3.4.2.1, "HPCS Testing," the HPCS system can be tested at full flow with CST water at any time during plant operation except when the reactor vessel water level is low, when the condensate level in the CST is below the reserve level or when the valves from the suppression pool to the pump are open. If an initiation signal occurs while testing the HPCS system, the system automatically returns from the test mode to the operating mode.

In the LAR, the licensee stated that testing of the Division 3 DG in the proposed manner (i.e., online) does not significantly interfere with normal operation. In a request for additional information (RAI) dated December 11, 2013 (ADAMS Accession No. ML12341A322), the NRC staff requested the licensee to discuss all potential interferences identified during the testing that could impact normal plant operation and plant safety systems.

In its letter dated January 7, 2013, in response to the NRC staff RAI, the licensee explained that there are no physical interferences to testing in the proposed manner. The licensee further stated that performance of the SRs [testing] on-line will not have an impact on plant safety systems nor normal plant operation any more than the performance of any other SR on-line. Before SRs are performed, whether on-line or off-line, they are planned, scheduled, and appropriately staffed. As part of the pre-performance process, equipment availability and current plant conditions are considered, plant risk is evaluated, and requisite administrative controls are put into place. As such, performance of these SRs on-line will not interfere with normal plant operation or impact plant safety systems.

The NRC staff finds the above explanation acceptable since performance of the affected Division 3 SRs online will not interfere with normal plant operation or impact plant safety systems.

Concerning the affected SRs, the NRC staff requested, in its RAI dated December 11, 2013, the licensee to confirm that the performance of SRs 3.8.1.9, 3.8.1.10, 3.8.1.11, 3.8.1.12, 3.8.1.13, and 3.8.1.16, at power will not have unacceptable voltage transients on the connected loads and will not affect other safety-related equipment or normal plant operation.

In response to the NRC staff RAI, the licensee stated in its letter dated January 7, 2013, that historical review of the control room narrative log and corrective action program database confirmed there were no perturbations on the emergency bus or electrical distribution system resulting from the performance of these SRs. Additionally, this review confirmed there were no effects on safety-related equipment connected to the emergency buses and no impact on normal plant operation. Voltage requirements on the emergency bus and electrical distribution system are not affected by specific plant modes of operation (that is, either on-line of off-line plant operation). Therefore, since there were no perturbations on the emergency bus or electrical distribution system, no effects on safety-related equipment connected to the emergency buses, and no effects on normal plant operation when the SRs were performed off-line, similar results are expected when the SRs are performed on-line.

The NRC staff finds the above explanation acceptable since the performance of the Division 3 SRs online would not affect voltage requirements on the emergency bus and electrical distribution system and would not impact other safety-related buses and equipment, or normal plant operation.

3.1 Review of SR 3.8.1.8

For Division 3, SR 3.8.1.8 requires verification of the manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit. This SR currently contains a Note that prohibits its performance in Mode 1 or 2. The TS Bases state that the reason for this Note is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. This surveillance is performed with the bus energized from the preferred offsite circuit. The alternate supply breaker is placed in the test position and an open condition is simulated in the normal supply breaker. The synchronization switch is then aligned to the alternate supply bus and the alternate supply breaker is closed to complete the manual transfer.

The licensee provided the following discussion in the LAR to justify their proposed mode restrictions removal for SR 3.8.1.8.

- The power system loading during this test is within the rating of all transformers, switchgear, and breakers, which thus are unaffected by the performance of this test.

- The Division 3 electrical loads do not approach the electrical load rating of either the Division 3 normal or alternate electrical distribution system; therefore there is no impact to the electrical distribution system, and no credible mechanism for challenging continued steady state operation when performing this SR for Division 3. In addition, buses are manually transferred on a periodic basis during monthly testing of the DG.

- The HPCS system is a stand-alone system with a dedicated Division 3 DG electrical distribution system. The Division 1 and 2 safety systems remain electrically isolated from the power sources undergoing testing. Performing SR 3.8.1.8 for Division 3, whether shutdown or online, affects only Division 3 equipment. Thus, due to the minimal size of the loads associated with the HPCS system and the manual transfer, there is no potential for this testing to create a perturbation on the electrical distribution systems including the grid.

The NRC staff reviewed the above discussion in the LAR and finds that the Division 3 loading during this test will not exceed the rating of the associated transformers, switchgears and breakers; testing of Division 3 DG will not affect Divisions 1 and 2 safety systems; and the performance of this test would not create perturbations in the electrical distribution system. Based on the above, the NRC staff finds the removal of mode restrictions in SR 3.8.1.8 (i.e. allowing the SR to be performed in Mode 1 or 2) for Division 3 DG acceptable.

3.2 Review of SRs 3.8.1.9 and 3.8.1.10

For Division 3, SR 3.8.1.9, verifies that the DG rejects a load greater than or equal to its associated single largest post-accident load (i.e., the 2,397 kilowatts (kW) HPCS pump). Following load rejection, engine speed is maintained less than nominal plus 75 percent of the difference between nominal speed and the overspeed trip setpoint or 15 percent above nominal, whichever is less. SR 3.8.1.10 verifies that the Division 3 DG (operating at a power factor less than or equal to 0.9) does not trip and voltage is maintained less than or equal to 5,000 V during and following a load rejection of a load is greater than or equal to 2,600 kW. These SRs currently contain a Note that prohibits their performance in Mode 1 or 2. Per the TS Bases, the reason for this Note is that during operation with the reactor critical, performance of these SRs could cause perturbations to the plant electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. For the performance of the load rejection tests per SR 3.8.1.9 and SR 3.8.1.10, the Division 3 DG is started, paralleled to the Division 3 emergency bus, and loaded to the required load. The DG output breaker is then opened to separate the DG from its associated emergency bus and allow the offsite circuit to continue to supply the bus.

The licensee provided the following discussion in the LAR to justify their proposed mode restrictions removal for SR 3.8.1.9 and SR 3.8.1.10.

- The power system loading during such testing is within the rating of all transformers, switchgears, and breakers, both before and after the load rejection.

- During operation at PNPP, the emergency buses are connected to either the normal or alternate offsite circuit. This is the same configuration maintained during plant shutdown when the load reject testing has been conducted. The probability for a grid disturbance to occur during the timeframe of a test performed per SR 3.8.1.9 or SR 3.8.1.10, is low, and the occurrence of a grid disturbance is considered independent of the testing. In addition, the degraded voltage and loss of voltage instrumentation required by TS 3.3.8.1, "Loss of Power (LOP) Instrumentation," would be available to respond to such a grid disturbance.

- Historical bus voltage data from performing these SRs for Division 3 DG has shown that the voltage during the transient remains within the required voltage range for plant loads. Thus, the voltage transient experienced by loads on the affected bus is minimal.

In its RAI dated December 11, 2013, the NRC staff requested the licensee to provide the historical key voltage parameters that were monitored during the last performance of SR 3.8.1.9 and SR 3.8.1.10.

In its response dated January 7, 2013, to the staff RAI, the licensee clarified that PNPP's TSs do not specifically require voltage data for SR 3.8.1.9, which is a partial load rejection test, to be recorded. However, voltage data was recorded for SR 3.8.1.10, which is a full-load rejection test. The results of SR 3.B.1.10 bound the results of SR 3.8.1.9, thus actual voltage data for SR 3.8.1.9 is not required to be documented. The maximum voltage recorded for SR 3.8.1.10 was 4,969 volts alternating current (VAC). This test is considered satisfactory if the voltage recorded is less than or equal to 5,000 VAC.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated January 7, 2013, and verified that the Division 3 loading during this testing is within the rating of all transformers, switchgears, and breakers, both before and after the load rejection; the maximum voltages monitored during these tests remain within the required range; and the degraded voltage and loss of voltage instrumentation would be available to respond and protect safety-related equipment in the event of a grid disturbance. Based on the above, the NRC staff finds the removal of mode restrictions in SRs 3.8.1.9 and 3.8.1.10 (i.e., allowing the SRs to be performed in Mode 1 or 2) for Division 3 DG acceptable.

3.3. Review of SRs 3.8.1.11 and 3.8.1.16

For Division 3, SR 3.8.1.11, verifies that upon an actual or simulated LOOP signal, the emergency bus is de-energized, and the DG automatically starts from the standby condition and energizes permanently connected loads in less than or equal to 13 seconds for Division 3, achieves and maintains the required steady-state voltage and frequency, and supplies permanently connected and auto-connected loads for greater than or equal to five minutes. SR 3.8.1.16 verifies that upon a simulated restoration of offsite power, the DG can be synchronized with an offsite power source while loaded with emergency loads, transfers loads to offsite power, and the DG returns to ready-to-load operation. These SRs currently contain a Note that prohibits its performance in Mode 1, 2, or 3, because, as stated in the TS Bases, performing these SRs would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems.

For the performance of SR 3.8.1.11, a LOOP is simulated by removing the control power fuses ahead of the undervoltage relays, causing the Division 3 emergency switchgear to de-energize, thereby isolating the Division 3 DG electrical subsystem from the other two safety-related electrical subsystems (Division 1 and Division 2). The Division 3 DG starts, re-energizes its associated emergency bus, and runs for at least five minutes. SR 3.8.1.16 is performed after completion of SR 3.8.1.11. After the Division 3 DG is run for at least five minutes with the HPCS and emergency service water pumps running, the HPCS is aligned in the test mode, with the HPCS pump suction from the CST and pump discharge through the test return line back to the CST. Thus, actual discharge of water into the reactor vessel by the HPCS system is prevented during this test. The Division 3 emergency bus is then paralleled to offsite power and the bus loads are transferred to the offsite power source. After the DG output breaker is opened, the DG is verified to return to ready-to-load operation.

The licensee provided the following discussion in the LAR to justify their proposed mode restrictions removal for SR 3.8.1.11 and SR 3.8.1.16.

- Although the offsite source of power to the Division 3 emergency bus is disconnected when performing this SR for Division 3, the period of time that this condition exists is small and deemed acceptable since the HPCS system is already inoperable for performance of the test (since the HPCS pump actually pumps water during this test, the flow path is aligned back to the condensate storage tank rather than to the reactor vessel, making the HPCS system inoperable). As discussed in the Note to the applicability requirements of TS 3.8.1, the Division 3 AC electrical power system is not required to be operable when the HPCS system is inoperable.

- Due to the relatively small size of the loads associated with the Division 3 HPCS system and the Division 1 and 2 safety systems remaining isolated from the power sources undergoing testing, there is minimal potential when performing these SRs for Division 3 to create an offsite power supply perturbation that could affect the Division 1 and 2 safety systems when the Division 3 emergency bus is de-energized and when shifting the load between the Division 3 DG and the offsite power source.

- The simulated LOOP signal is generated at the Division 3 switchgear and does not affect the Division 1 and 2 electrical divisions or their associated loads. Completed test results performed during shutdown conditions have shown that the required bus voltage parameters remain within expected limits and no unusual actions regarding load transfer sequences occur. Conducting this test for Division 3 online is not expected to be more challenging to plant safety systems than performance during shutdown conditions.

- Features of the HPCS system allow testing of the Division 3 system online without discharging into the reactor vessel, while providing protection of the pump from overheating. Additionally, system configuration is such that HPCS system testing can be performed without impacting other divisional safety systems or the RCIC system. HPCS pump starts and stops are periodically performed online to satisfy quarterly inservice testing requirements without disturbing plant operations. As such, there is minimal opportunity for the performance of this SR for the Division 3 DG to have an impact on other safety-related plant equipment or normal plant operations.

In its RAI dated December 11, 2013, the NRC staff requested the licensee to provide the key voltage parameters that were monitored during the last performance of SR 3.8.1.11 and SR 3.8.1.16.

In response to the NRC staff RAI, the licensee stated, in its letter dated January 7, 2013, that the steady-state voltage recorded for SR 3.8.1.11 was 4,150 VAC. The steady-state voltage recorded for SR 3.8.1.16 was 4,322 VAC. Both tests are considered satisfactory if the voltage recorded is greater than or equal to 3,900 VAC and less than or equal to 4,400 VAC. Also, during a conference call with the licensee on February 1, 2013, the licensee confirmed that the frequency recorded during the last performance of this surveillance was within the required range.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated January 7, 2013, and verified that the maximum voltages monitored during these tests are within the required range. Also, the NRC staff finds that the Division 3 HPCS system can be tested without impacting Divisions 1 and 2 safety systems or the RCIC system, and therefore, these plant safety systems will be available to perform their intended safety functions. Based on the above, the NRC staff finds the removal of mode restrictions in SR 3.8.1.11 and SR 3.8.1.16 (i.e., allowing the SRs to be performed in Mode 1, 2 or 3) for Division 3 DG acceptable.

3.4 Review of SR 3.8.1.12

For Division 3, SR 3.8.1.12, verifies that upon an actual or simulated emergency core cooling system (ECCS) initiation signal, the DG automatically starts from the standby condition and achieves the required voltage and frequency in less than or equal to 13 seconds, and operates for greater than or equal to five minutes. This SR currently contains a Note that prohibits its performance in Mode 1 or 2 because, as stated in the TS Bases, performing this SR could cause perturbations to the electrical distribution system that could challenge continued steady state operation and, as a result, plant safety systems. This surveillance is performed by closing a temporary test switch installed on the Division 3 auxiliary relay panel to insert an ECCS initiation signal into the Division 3 control logic. The Division 3 DG then starts and runs unloaded with the DG output breaker open for greater than or equal to five minutes while acceptable voltage and frequency are verified.

The licensee provided the following discussion in the LAR to justify their proposed mode restrictions removal for SR 3.8.1.12:

- Since this test is conducted with the Division 3 DG unloaded and isolated from its emergency bus, there is no impact to the electrical distribution system, and no mechanism for challenging continued steady state operation.

- The Division 3 power system is an electrically separated distribution system with a dedicated DG. Therefore, there is minimal opportunity for the performance of this SR for the Division 3 DG to have any impact on other safety-related plant equipment or normal plant operation. When performing this SR for Division 3, the simulated ECCS initiation signal is generated only in the Division 3 logic and does not affect the Division 1 and 2 safety-related electrical divisions or their associated loads.

In response to the NRC staff request for key voltage parameters monitored during the last performance of SR 3.8.12, the licensee stated, in its letter dated January 7, 2013, that the steady-state voltage recorded for SR 3.8.1.12 was 4,218 VAC. This test is considered satisfactory if the voltage recorded is greater than or equal to 3,900 VAC and less than or equal to 4,400 VAC. Also, during a conference call with the licensee on February 1, 2013, the licensee confirmed that the frequency recorded during the last performance of this surveillance was within the required range.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated January 7, 2013, and verified that the maximum voltage monitored during this test is within the required range. Additionally, the NRC staff finds that with the Division 3 DG unloaded and isolated from its emergency bus, there will be no impact to the electrical distribution system and plant safety systems. Based on the above, the NRC staff finds the removal of mode restrictions in SR 3.8.1.12 (i.e., allowing the SR to be performed in Mode 1 or 2) for Division 3 DG acceptable.

3.5 Review of SR 3.8.1.13

For Division 3, SR 3.8.1.13, verifies that the DG's automatic trips are bypassed on an actual or simulated ECCS initiation signal, except for the engine overspeed and DG differential current trips, as described in the UFSAR, Section 8.3.1.1.3.3. This SR currently contains a Note that prohibits its performance in Mode 1, 2, or 3. The TS Bases state the reason for this Note is that performing this SR could cause perturbations to the electrical distribution system that could challenge continued steady state operation and, as a result, plant safety systems. Portions of this SR are performed with the Division 3 DG output breaker open in the test position. The associated output breaker cell switch contacts are secured in place to simulate the breaker in a connected position. The DG is remotely started. Simulated paralleling of the DG to its associated emergency bus is performed by using the synchronization selector switch and the closure of the Division 3 DG output breaker. While the DG output breaker is closed and isolated from its associated emergency bus, it is confirmed that the reverse power and instantaneous overcurrent trips are bypassed and that both an engine overspeed and a DG differential current condition will trip the DG on a simulated ECCS initiation signal. The testing is completed with the output breaker reconnected, but tripped open. With a Division 3 LOCA signal inserted, it is confirmed that the DG jacket water temperature high and lube oil pressure low trips are bypassed (the DG does not trip).

The licensee provided the following discussion in the LAR to justify their proposed mode restrictions removal for SR 3.8.1.13:

- SR 3.8.1.13 is not performed with the Division 3 DG paralleled to offsite power and the unavailability of the Division 3 DG during the conduct of this test is minimal. Since this test is conducted with the Division 3 DG unloaded and isolated from its emergency bus when performing this SR for Division 3, there is no impact to the electrical distribution system, and no mechanism exists for challenging continued steady state operation.

- When performing this SR for Division 3, whether shutdown or online, the simulated ECCS initiation signal is generated only in the Division 3 logic and does not affect the other two safety-related electrical divisions or their associated loads.

In response to the NRC staff RAI, the licensee stated in its letter dated January 7, 2013, that this test demonstrates that DG non-critical protective functions are bypassed on an ECCS initiation test signal and critical protective functions trip the DG to avert substantial damage to the DG unit. Also, during a conference call with the licensee on February 1, 2013, the licensee clarified that the Division 3 DG will be unavailable during portions of the test and the unavailability is minimal considering the entire duration of the test and the 24-month surveillance frequency.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated January 7, 2013, and verified that this test is conducted with the Division 3 DG unloaded and isolated from its emergency bus, and therefore, there will be no impact to the electrical distribution system and plant safety systems. Based on the above, the NRC staff finds the removal of mode restrictions in SR 3.8.1.13 (i.e., allowing the SR to be performed in Mode 1, 2, or 3) for Division 3 DG acceptable.

3.6 Review of SR 3.8.1.17

For Division 3, SR 3.8.1.17, verifies that with the DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by returning the DG to ready-to-load operation and automatically energizing the emergency loads from offsite power.

This SR currently contains a Note that prohibits its performance in Modes 1, 2, or 3. The TS Bases state the reason for this Note is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. This test is performed by simulating an ECCS signal to the Division 3 DG start circuitry while the DG is paralleled with the offsite source. The ECCS signal causes the DG output breaker to open and the DG to return to a ready-to-load condition.

The licensee provided the following discussion in the LAR to justify their proposed mode restrictions removal for SR 3.8.1.17:

- Opening the DG output breaker separates the Division 3 DG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. Performance of this test does not cause any significant perturbations to the electrical distribution systems as the DG is separated from the bus. In addition, the power system loading for this test is within the rating of the associated transformers, switchgear, and breakers, both before and after the load rejection.

- As noted in the TS Bases for this SR, the intent of SR 3.8.1.17 is to show that the emergency loading is not affected by DG operation in the test mode. Performance of testing required pursuant to this SR does not involve separating the bus from offsite power, so performance of this surveillance would not "remove an offsite circuit from service, perturb the electrical distribution system, and challenge safety systems," as currently stated in the TS Bases for this SR.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated January 7, 2013, and finds that the Division 3 loading during this test will not exceed the rating of the associated transformers, switchgears and breakers, both before and after the load rejection; the offsite power source will continue to power the emergency buses; and plant safety systems will not be challenged. Based on the above, the NRC staff finds the removal of mode restrictions in SR 3.8.1.17 (i.e., allowing the SR to be performed in Mode 1, 2, or 3) for Division 3 DG acceptable.

3.7 Review of SR 3.8.1.19

For Division 3, SR 3.8.1.19, verifies that upon an actual or simulated LOOP signal in conjunction with an actual or simulated ECCS initiation signal, the emergency bus is de-energized, the DG automatically starts from the standby condition and energizes permanently connected and auto-connected loads in less than or equal to 13 seconds, achieves and maintains the required voltage and frequency, and supplies permanently connected and auto-connected loads for greater than or equal to five minutes. This SR currently contains a Note that prohibits its performance in Mode 1, 2, or 3. Per the TS Bases, the reason for this Note is that performing the SR would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems. With the Division 3 emergency bus aligned to either the preferred or alternate preferred offsite circuit, a LOOP signal is simulated by tripping open the appropriate offsite source breaker carrying load to the Division 3 emergency buses while simultaneously inserting an ECCS initiation signal into the Division 3 control logic. The Division 3 DG starts, re-energizes its associated emergency bus, and powers the HPCS pump and other permanently connected loads. For this test, the HPCS pump suction is from the suppression pool, and pump discharge is through the minimum flow line back to the suppression pool.

The licensee provided the following discussion in the LAR to justify their proposed mode restrictions removal for SR 3.8.1.19:

- Although the offsite source of power to the Division 3 emergency bus is disconnected when performing this SR for Division 3, the period of time that this condition exists is small and deemed acceptable since the HPCS system is already inoperable for performance of the test and the Division 3 AC sources are not required to be operable per the Note associated with the Applicability requirements for TS 3.8.1.

- Due to the relatively small size of the loads associated with the HPCS system (2397 kW), there is minimal potential for this testing to create an offsite power supply perturbation when the Division 3 electrical bus, is de-energized.

- Features of the HPCS system allow testing of the system online without discharging into the reactor vessel, while providing protection of the pump from overheating. Additionally, system configuration is such that HPCS system testing can be performed without impacting other divisional safety systems or the RCIC system. HPCS pump starts and stops are routinely performed online to satisfy quarterly inservice testing requirements, without disturbing plant operations.

- The simulated LOOP and ECCS initiation signals associated with this SR for Division 3 affect only Division 3 and do not affect the other two safety-related electrical divisions.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated January 7, 2013, and finds that testing of the HPCS system can be performed online without impacting Divisions 1 and 2 safety systems or the RCIC system, and therefore, these plant safety systems will be available to perform their intended safety functions. Based on the above, the NRC staff finds the removal of mode restrictions in SR 3.8.1.19 (i.e., allowing the SR to be performed in Mode 1, 2, or 3) for Division 3 DG acceptable.

3.8 Removal of Expired Temporary Provisions for a Delayed Access Circuit

The licensee proposes, in this LAR, to delete the temporary TS 3.8.1 provisions related to the use of the delayed access circuit in place of the circuit associated with the Unit 1 startup transformer. The provisions expired on December 12, 2011. The licensee stated that the proposed changes to remove the mode restrictions associated with the Division 3 SRs do not rely upon removal of the expired provisions. The licensee also stated that removal of the TS 3.8.1 delayed access circuit provisions is included in the LAR as a matter of processing convenience only. The NRC staff finds the removal of the temporary provisions acceptable because the provisions expired on December 12, 2011 and their removal does not change the intent of TS 3.8.1 nor does it affect the proposed mode restrictions removal associated with the Division 3 SRs.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Ohio State official was notified of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

This amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 [or changes a surveillance requirement]. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluent that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that this amendment involves no significant hazards consideration and there has been no public comment on such finding (77 FR 67682; November 13, 2012). Accordingly, this amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

6.0 CONCLUSION

The NRC staff reviewed the licensee's proposed changes to the subject SRs. The changes would remove mode restrictions on SR 3.8.1.8, SR 3.8.1.9, SR 3.8.1.10, and SR 3.8.1.12, currently prohibited to be performed in Mode 1 or 2. The changes would also remove mode restrictions on SR 3.8.1.11, SR 3.8.1.13, SR 3.8.1.16, SR 3.8.1.17, and SR 3.8.1.19, currently prohibited to be performed in Mode 1, 2, or 3, for Division 3 DG. Based on the above technical evaluation in Section 3.0 of this safety evaluation, the NRC staff concludes that the proposed TS changes provide reasonable assurance of the continued availability of the required electrical power and safety systems to shut down the reactor and keep the reactor in a safe condition after an anticipated operational occurrence. Furthermore, the NRC staff concludes that the proposed TS changes are in accordance with 10 CFR 50.36(c) and meet the intent of GDC 17, and GDC 18. Therefore, the NRC staff finds the proposed changes in the LAR acceptable.

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

Principal Contributor: A. Foli, NRR

Date of issuance: March 7, 2013

Mr. Vito A. Kaminskas
Site Vice President
FirstEnergy Nuclear Operating Company
Perry Nuclear Power Plant
Mail Stop A-PY-A290
P.O. Box 97, 10 Center Road
Perry, OH 44081-0097

SUBJECT: PERRY NUCLEAR POWER PLANT, UNIT NO. 1 - ISSUANCE OF AMENDMENT RE: MODIFY TECHNICAL SPECIFICATION 3.8.1, "AC SOURCES – OPERATING," TO REMOVE MODE RESTRICTIONS ON CERTAIN DIVISION 3 SURVIELLANCE REQUIREMENTS (TAC NO. ME9006)

Dear Mr. Kaminskas:

The U.S. Nuclear Regulatory Commission (NRC, the Commission) has issued the enclosed Amendment No. 162 to Facility Operating License No. NPF-58 for the Perry Nuclear Power Plant, Unit No. 1. This amendment revises the Technical Specifications (TSs) in response to your application dated July 3, 2012, supplemented by letter dated January 7, 2013.

This amendment revises TS 3.8.1, "AC [alternating current] Sources - Operating," to modify nine surveillance requirements (SRs) by excluding Division 3 from current mode restrictions, thus allowing performance of the subject SRs in any mode of plant operation.

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

Sincerely,

Michael Mahoney, Project Manager
Plant Licensing Branch III-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-440

Enclosures:
1. Amendment No. 162 to NPF-58
2. Safety Evaluation

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Amendment Accession No. ML13052A706

OFFICE	LPL3-2/PM	LPL3-2/LA	DE/EEEB/BC	OGC	LPL3-2/BC
NAME	MMahoney	SRohrer	RMathew (Acting)	AGhosh (NLO w/ Comments)	JBowen
DATE	3/5/13	2/21/13	2/11/13	3/5/13	3/7/13

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