October 2, 2000

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Mr. Mike Reandeau
Director - Licensing
Clinton Power Station
P.O. Box 678
Clinton, IL 61727

SUBJECT: CLINTON POWER STATION, UNIT 1 - ISSUANCE OF AMENDMENT (TAC NO. MA9269)

Dear Mr. Reandeau:

The U.S. Nuclear Regulatory Commission (Commission) has issued the enclosed Amendment No. 132 to Facility Operating License No. NPF-62 for the Clinton Power Station, Unit 1. The amendment is in response to your application dated June 19, 2000, as supplemented August 8, 2000.

The amendment allows some emergency diesel generator Technical Specification surveillance requirements to be performed during plant operation instead of during plant shutdown.

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,

/RA/

Jon B. Hopkins, Senior Project Manager, Section 2
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-461

Enclosures: 1. Amendment No. 132 to NPF-62
2. Safety Evaluation

cc w/encls: See next page

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

October 2, 2000

Mr. Mike Reandeau
Director - Licensing
Clinton Power Station
P.O. Box 678
Mail Code V920
Clinton, IL 61727

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Dear Mr. Reandeau:

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Sincerely,

Jon B. Hopkins, Senior Project Manager, Section 2
Project Directorate III
Division of Licensing Project Management
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Docket No. 50-461

Enclosures: 1. Amendment No. 132 to NPF-62
2. Safety Evaluation

cc w/encls: See next page

Mike Reandeau

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

AMERGEN ENERGY COMPANY, LLC

DOCKET NO. 50-461

CLINTON POWER STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 132
License No. NPF-62

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

   A. The application for amendment by AmerGen Energy Company, LLC (the licensee), dated June 19, 2000, as supplemented August 8, 2000, 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-62 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 132 are hereby incorporated into this license. AmerGen Energy Company, LLC 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 issuance and shall be implemented within 30 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Anthony J. Mendiola, Chief, Section 2
Project Directorate III
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: October 2, 2000

ATTACHMENT TO LICENSE AMENDMENT NO. 132

FACILITY OPERATING LICENSE NO. NPF-62

DOCKET NO. 50-461

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

Remove Pages	Insert Pages
3.8-6a	3.8-6a
3.8-7	3.8-7
3.8-9	3.8-9
3.8-10	3.8-10
3.8-11	3.8-11

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTE---------- 1. 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 and following load rejection, the 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 lower.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.10	----------NOTE---------- 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 ≤ 5000 V for DG 1A and DG 1B and ≤ 5824 V for DG IC during and following a load rejection of a load ≥ 3482 kW for DG 1A, ≥ 3488 kW for DG 1B, and ≥ 1980 kW for DG 1C.	18 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. 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 ≤ 12 seconds after auto-start and during tests, achieves voltage ≥ 4084 V and frequency ≥ 58.8 Hz; b. Achieves steady state voltage ≥ 4084 V and ≤ 4580 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and c. Operates for ≥ 5 minutes.	18 months
SR 3.8.1.13	----------NOTES---------- 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; b. Generator differential current; and c. Overcrank for DG 1A and DG 1B.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 4062 kW for DG 1A, ≥ 4069 kW for DG 1B, and ≥ 2310 kW for DG 1C; and b. For the remaining hours of the test loaded ≥ 3482 kW for DG 1A, ≥ 3488 kW for DG 1B, and ≥ 1980 kW for DG 1C.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	----------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 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.	18 months
SR 3.8.1.17	----------NOTE---------- 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.	18 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. 132 TO FACILITY OPERATING LICENSE NO. NPF-62

AMERGEN ENERGY COMPANY, LLC

CLINTON POWER STATION, UNIT 1

DOCKET NO. 50-461

1.0 INTRODUCTION

By letter dated June 19, 2000, as supplemented August 8, 2000, AmerGen Energy Company, LLC (AmerGen or the licensee), proposed an amendment to the Clinton Power Station (CPS) Technical Specifications (TSs). The proposed amendment would allow some emergency diesel generator (EDG) TS surveillance requirements to be performed during plant operation instead of during plant shutdown.

The amendment proposes a revision to the surveillance requirements (SRs) pertaining to testing of the standby EDGs. The proposed change would remove the restrictions in SRs 3.8.1.9, 3.8.1.10, and 3.8.1.14 that prohibit performing the required testing during Modes 1 and 2, and the restrictions in SRs 3.8.1.13 and 3.8.1.17 that prohibit performing the required testing during Modes 1, 2, and 3. This change would provide flexibility in outage scheduling and reduce outage critical path time since these EDG surveillance tests would no longer have to be performed during an outage.

The supplemental submittal provided additional information and did not change the requested amendment or affect the proposed no significant hazards consideration.

2.0 BACKGROUND

The Class 1E alternating current electrical power distribution system sources at CPS consist of the offsite power sources and the onsite standby power sources, that is, EDGs 1A, 1B, and 1C. The Class 1E distribution system supplies electrical power to three divisional load groups, and each division is powered by an independent Class 1E 4.16-kV emergency safety feature (ESF) bus. Each ESF bus is capable of being supplied by either of two separate and independent offsite sources of power. Each ESF bus also has a dedicated onsite EDG. The ESF systems of any two of the three divisions provide for the minimum safety functions necessary to shut down the plant and maintain it in a safe-shutdown condition.

Offsite power is supplied to the CPS switchyard from the transmission network. The 345-kV circuit provides power to each of the 4.16-kV ESF buses from the switchyard via the onsite reserve auxiliary transformer (RAT). Alternatively, an electrically and physically independent 138-kV power source can provide power to each of the 4.16-kV ESF buses via the emergency reserve auxiliary transformer (ERAT). The unit auxiliary transformer supplies power to the non-safety-related loads using the main generator as a power source. The offsite electrical power sources are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A permanently installed static VAR compensator (SVC) is also available for connection to each offsite circuit to support the required voltage for each ESF bus.

The onsite standby power source for each 4.16-kV ESF bus is a dedicated EDG. An EDG starts automatically upon receipt of a loss-of-coolant accident (LOCA) signal (i.e., low reactor water level signal or high drywell pressure signal) or an ESF bus degraded voltage or undervoltage signal. In the event of a loss of offsite power (LOOP), the ESF electrical loads are automatically connected to the EDGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a design basis accident such as a LOCA.

3.0 EVALUATION

The licensee provided the following information in support of the requested changes.

At present, TS SRs 3.8.1.9 (largest load rejection test), 3.8.1.10 (full-load rejection test), 3.8.1.13 (non-emergency automatic trip bypass test), 3.8.1.14 (24-hour load run), and 3.8.1.17 (test mode override) must be performed while the plant is shutdown. For SRs 3.8.1.9, 3.8.1.10, and 3.8.1.14, this requirement is enforced by a note preceding each of the SRs in the TS that states, in part, that the surveillance shall not be performed in Mode 1 or 2. The TS Bases state that the reason for this restriction is to prevent unnecessary perturbations to the electrical distribution systems, which could challenge steady-state operation and thus, plant safety systems, if the SR was performed with the reactor in Mode 1 or 2. SRs 3.8.1.13 and 3.8.1.17 are restricted from being performed in Mode 1, 2, or 3 as these surveillances are preceded by a similar note. The TS Bases for SR 3.8.1.13 state that the reason for the note is to prevent the EDG from unnecessarily being removed from service with the reactor in Mode 1, 2, or 3. The TS Bases for SR 3.8.1.17 state that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems.

The licensee is proposing to modify the note to remove the Mode 1 and 2 restrictions for performance of SRs 3.8.1.9, 3.8.1.10, and 3.8.1.14, and to remove the Mode 1, 2, and 3 restrictions from SRs 3.8.1.13 and 3.8.1.17. The proposed changes will allow performance of the testing required by these SRs during Modes 1 and 2 (or Mode 3) such that the testing will no longer have to be performed during plant outages. This measure will help to reduce the complexity of work and testing activities during refueling outages and will potentially reduce outage critical path time. The licensee is also proposing to revise the TS Bases associated with SRs 3.8.1.9, 3.8.1.10, 3.8.1.13, 3.8.1.14, and 3.8.1.17 to state that these surveillances should be conducted on only one EDG at a time, with the EDG on a separate source from the rest of the unit's distribution systems. This step is performed to preclude the possibility of

common-cause failures from offsite grid perturbations that could affect EDG performance while the EDG(s) is connected (paralleled) to the offsite power source and to minimize perturbations to the plant's other distribution systems.

Specifically, Note 1 for SRs 3.8.1.9 and 3.8.1.10 and Note 2 for SR 3.8.1.14 currently read as follows, "This surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR." The notes for SRs 3.8.1.13 and 3.8.1.17 are identical except that they also include Mode 3. The note for each of these SRs will be revised to remove the mode restrictions from the first part of the note such that the note (or the affected portion of the note) would be reduced to the following, "Credit may be taken for unplanned events that satisfy this SR."

The TS Bases for SRs 3.8.1.9, 3.8.1.10, and 3.8.1.14 will also be revised to remove the sentence that makes the following statement, "The reason for [the 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." The TS Bases for SR 3.8.1.17 will be revised to remove the statement that makes the following statement, "The reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems."

The following statement will be added to the TS Bases for each of the above mentioned SRs, "Testing performed for this SR is normally conducted with the EDG being tested (and the associated safety-related distribution subsystem) connected to one offsite source, while the remaining safety-related (and non-safety-related) distribution systems are aligned to the other offsite source (or unit auxiliary transformers). This measure minimizes the possibility of common-cause failures resulting from offsite/grid voltage perturbations." The TS Bases for SR 3.8.1.13 will be revised to remove the following statement, "The reason for the Note is that performing the surveillance removes a required EDG from service."

Although the TS Bases, as currently written, state that the reason for the SR note (for SRs 3.8.1.9, 3.8.1.10, and 3.8.1.14) is to preclude the potential for perturbations of the electrical distribution system during plant operation, reconsideration of this has determined that the noted concern is unwarranted with respect to requiring the affected SRs to be performed only during shutdown conditions. This conclusion is based on industry and plant experience with the performance of testing required by the affected SRs, realistic consideration of the conditions typically present during performance of the affected testing, and the low probability of a significant voltage perturbation during such testing. Such testing does not make the EDG unavailable for responding to an accident during the testing, and the risk of performing the noted required surveillance during plant operation is not significantly greater than the risk associated with the performance of other EDG surveillance required by the TS, but not prohibited from being performed during plant operation.

Except as noted below for SR 3.8.1.13, performance of the affected SRs does not result in any unavailability of the EDGs. (Performance of some portions of these SRs may result in momentary EDG inoperability, but in general, EDG availability is not significantly affected.) Also, no other safety-related equipment is rendered inoperable by the performance of these

SRs. SRs 3.8.1.9, 3.8.1.10, 3.8.1.14, and 3.8.1.17 are performed by paralleling the EDG being tested with offsite power, similar to the existing monthly run of the EDG, which is conducted with the plant on line. In the event of any occurrence that would cause EDG protective devices to actuate during the performance of these SRs, the EDG will separate from its respective emergency bus, allowing the offsite circuit to continue to supply the bus. Further, performance of the required testing at power would not result in the inoperability of any other safety-related equipment, nor would it result in a challenge to any plant safety system.

The licensee provided additional discussions in support of each of the SRs as follows:

Testing Pursuant to SRs 3.8.1.9 and 3.8.1.10

For performance of the load rejection tests in accordance with SRs 3.8.1.9 and 3.8.1.10, the typical approach taken is to load the tested EDG to the required load (through offsite power) and then open the EDG output breaker. Opening of the EDG output breaker separates the EDG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. This evolution has little impact on plant loads. The power system loading during such testing is within the rating of all transformers, switchgear, and breakers, both before and after the load rejection, and as further explained below, performance of the load rejection SRs does not cause any significant perturbations to the electrical distribution systems as the EDG is separated from the bus.

Data from testing performed pursuant to these SRs are recorded by the General Electric Transient and Recording System (GETARS) at CPS. Analysis of bus voltage traces taken from GETARS for previous tests shows that the voltage drop that occurs is such that voltage during the "transient" remains well above the minimum required voltage for plant loads and typically recovers well within 2 seconds. Thus, the voltage "transient" experienced by loads on the affected bus is minor. It may be noted, too, that with the associated SVC in service, voltage perturbations are further minimized as a result of the compensating effect of the SVC.

In addition, the potential for occurrence of a compounding grid disturbance during the time frame of a test performed in accordance with SR 3.8.1.9 or 3.8.1.10 is remote, as the probability of occurrence of a sustained low-voltage condition on the grid is independent of testing performed pursuant to these SRs (That is, there is no credible consequential connection between the occurrence of a grid low-voltage condition and the performance of testing to satisfy SRs 3.8.1.9 and 3.8.1.10). Regardless, protective relaying for the EDG would be available to protect the EDG while it is connected to the grid. In addition, with respect to plant loads connected to the safety bus, the protection instrumentation (which must be operable in accordance with TS 3.3.8.1, "Loss of Power [(LOP)] Instrumentation") for sustained grid low-voltage conditions would be available to respond to such a condition for protection of the plant loads, irrespective of the testing performed in accordance with SRs 3.8.1.9 and 3.8.1.10.

Testing Pursuant to SR 3.8.1.17

Performance of the test mode override test in accordance with SR 3.8.1.17 ensures that the availability of the EDG under accident conditions is unaffected during the performance of the surveillance test. This test is typically performed in conjunction with the load rejection tests

(while the EDG is paralleled with the offsite source) by simulating a LOCA signal to the EDG start circuitry, which causes the EDG output breaker to open, as the EDG is returned to a ready to-load condition. Similar to the tests performed for SRs 3.8.1.9 and 3.8.1.10, opening the EDG output breaker separates the EDG from its associated emergency bus and allows the offsite circuit to continue to supply the bus. Consequently, performance of testing pursuant to SR 3.8.1.17 does not cause any significant perturbations to the electrical distribution systems as the EDG is separated from the bus. In addition, similar to testing performed for SRs 3.8.1.9 and 3.8.1.10, the power system loading for this test is within the rating of the affected transformers, switchgear, and breakers, both before and after the load rejection.

Testing Pursuant to SR 3.8.1.13

Performance of testing required in accordance with SR 3.8.1.13 to verify that non-emergency automatic trips are bypassed and that emergency automatic trips will trip the EDG in an emergency, while at power, is justified on the basis that (1) this SR is not performed with the EDG paralleled to offsite power and (2) unavailability of the EDG during the conduct of this test is minimal. EDG unavailability mainly occurs when the EDG is tripped in response to the emergency trips and then is verified as tripped before resetting the trips. Manual action is required to reset the emergency trips, so that the EDG can then be available to start in an actual emergency situation. Since the test is conducted with the EDG unloaded and isolated from its respective emergency bus, there is no impact on the electrical distribution system. Therefore, there is no mechanism for challenging continued steady-state operation.

The test is performed by verifying that the non-emergency automatic trips do not trip the EDG (i.e., the associated lockout relay is not tripped). The only jumpering and signal simulation required is executed at the relay level in the EDG control circuitry such that only the associated EDG is affected during this surveillance. On the basis of test experience to date, EDG inoperability for performance of this testing during plant operation would be on the order of one hour per EDG per operating cycle.

Testing Pursuant to SR 3.8.1.14

Performance of the 24-hour run in accordance with SR 3.8.1.14 while at power is justified, in part, by the fact that CPS currently tests its EDGs paralleled to offsite power on a monthly basis, with the reactor critical, for approximately 1 to 2 hours. The intent of the 24-hour run, which is to demonstrate the ultimate load-carrying capability of the EDG, is met whether the test is conducted with the plant on line or shutdown. Protective device reliability is unaffected by this proposed change.

Normal practices of risk management would ensure that this SR would not be scheduled during periods in which the potential for grid or bus disturbances exists (such as during severe weather conditions or maintenance activities affecting the bus). Also, during the conduct of this test during plant operations, the other two remaining EDGs, including their support systems, would remain operable during the conduct of the 24-hour run. It is acknowledged that when the EDG is paralleled to offsite power, the affected train of the emergency power system is not independent of disturbances on the offsite power system or any potential interaction with the EDG (e.g., an EDG trip may result from overcurrent or reverse power, or a lockout device may

be actuated). The primary concern of EDG operation in parallel with offsite power is that loss of the offsite source could result in the loss or unavailability of an EDG (although this loss or unavailability would be temporary if it merely involved resetting the EDG lockout relay). However, the probability of an EDG being rendered unavailable as a result of a grid disturbance, coupled with the probability of such a disturbance (concurrent with EDG testing), is quite remote.

CPS procedures contain precautions to minimize risk associated with surveillance testing, maintenance activities, and degraded grid conditions when paralleling an EDG with offsite power. For example, during testing, only one EDG at a time is operated in parallel with offsite power. This configuration provides for sufficient independence of the onsite power sources from offsite power while still enabling testing to demonstrate EDG operability. In this configuration, it is possible for only one EDG to be affected by an unstable offsite power system. Even then, it may be possible for operator action to be taken to manually reset the affected lockout relay so that the EDG can be restarted. Additionally, if this unlikely scenario occurred, plant safe-shutdown capability would still be assured with the two remaining EDGs.

In addition to the above information, the staff reviewed the postulated events associated with the EDG start signals in relation to the proposed change to the EDG 24-hour surveillance at power. The events to be discussed are (1) a LOOP, (2) a safety injection (SI) without a LOOP, and (3) an SI with a LOOP.

(1) In response to a LOOP during emergency EDG testing (i.e., with the EDG running and paralleled to the offsite power source through the associated 4-kV bus), the EDG would attempt to supply power to the loads on the safety-related 4-kV bus and the loads (or fault) on the grid (assuming the grid remains connected to the bus). Because the grid loading greatly exceeds the EDG capability, the bus voltage and frequency would drop significantly. The EDG would momentarily respond by raising generator field current through its voltage regulator to support the bus voltage and by increasing the fuel supply to the engine through its governor to support the bus frequency. This response, however, would have a negligible effect on restoring the grid and would eventually lead to an actuation of either the first-level undervoltage relays or the EDG voltage-restrained overcurrent relays, as further described below.

In the event of an undervoltage condition, the first-level undervoltage relays would trip the main or reserve feed breaker to separate the bus from the grid. When this separation occurs, the EDG would then be able to maintain bus voltage and frequency in the specified range. It should be noted that for the Division 3 EDG, the 4-kV bus frequency would remain slightly elevated following a LOOP event because of the manual droop setting on the governor for the Division 3 EDG. However, the operating and surveillance procedures direct the operators to restore frequency to its acceptable range following a LOOP event by using the governor "raise" and "lower" switches in the main control room. In the event of a sustained overcurrent condition, the EDG voltage-restrained overcurrent relays would energize an auxiliary relay. This auxiliary relay would immediately trip the main or reserve feed breaker for the respective divisional

bus to separate the bus from the grid and energize a time-delay relay. The time-delay relay is designed to trip the EDG output breaker if the overcurrent condition exists longer than the time setting of the auxiliary relay. However, for the overcurrent condition caused by the LOOP, the EDG output current would drop below the setpoint of the overcurrent relay upon opening of the main or reserve feed breaker (well before the overcurrent relay time delay would time out), thereby not initiating an EDG output breaker trip signal and allowing the EDG to continue supplying power to the bus. Again, for the Division 3 EDG, manual operator action could be required to restore EDG frequency to the acceptable range.

(2) For a LOCA with SI during EDG testing, the EDG response is as described in Updated Safety Analysis Report (USAR) Section 8.3.1. That is, the EDG test mode is overridden by the SI actuation signal such that upon receipt of the SI actuation signal, the EDG output breaker will trip open and the RAT or the ERAT will continue to supply power to the connected loads. The EDG will continue to operate at nominal speed and voltage in a standby condition and would be capable of automatically connecting to its 4-kV bus if there is a subsequent LOOP event. This capability (for the SI actuation signal to override the EDG test mode and return the EDG to a ready-to-load condition) is periodically verified by performance of the testing required by TS SR 3.8.1.17.

It should be noted that in response to the SI actuation signal, droop control on the EDG voltage regulator and the electronic governor will automatically switch over to the isochronous mode of operation as required by Institute of Electrical and Electronics Engineers, Inc., (IEEE) 387, "Standard Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations." This action ensures that the EDG will run at rated speed when supplying the bus on its own after separating from the offsite power source. Again, an exception to this description is the manual droop control for the mechanical governor on the Division 3 EDG, as described and addressed in Amendment 119 to the CPS operating license.

It is also noted that for all three EDGs, noncritical protective trips are bypassed on a LOCA signal to preclude spurious trips of the EDG.

(3) Consideration of a LOOP occurring with a LOCA (SI initiation signal) while an EDG is in a test mode involves a highly improbable combination of events or conditions. Certain sequences that could be postulated for such a highly improbable scenario would be considered to be beyond the design or licensing basis of the facility. Notwithstanding, given such an unlikely scenario, the response of an EDG to a LOOP and SI while the EDG is being tested (i.e., paralleled to the offsite power source) is dependent on which of the two events/ conditions (LOOP or LOCA) occurs first (or whether the two events/conditions are assumed to occur simultaneously). When an EDG is being tested and the LOOP follows or occurs simultaneously with the LOCA, there is no impact on proper loading of the EDG because either of the following will occur:

(a) For a LOCA occurring while the EDG is being tested followed by a LOOP, the LOCA (SI initiation) signal will override the test mode and immediately ensure the EDG is brought to a ready-to-load condition, as previously described. (That is, the EDG will be in a standby condition, running at rated speed and voltage, with the EDG output breaker ready to close onto the bus on demand.) Upon occurrence of the subsequent LOOP, the EDG output breaker will close the EDG onto the bus, and the associated plant loads (ESF equipment) will be sequenced onto the bus by the associated delay timers (which prevent the simultaneous starting of the large ESF motors, thus precluding overloading of the EDG in accordance with the plant design).

(b) For a LOCA occurring simultaneously with a LOOP, while the EDG is being tested, the LOCA (SI initiation) signal will override the test mode and open the EDG output breaker (to return the EDG to a ready-to-load condition). As soon as the EDG output breaker permissive logic is satisfied (i.e., the EDG is at rated speed and/or voltage, the associated offsite source circuit feed breakers are open, and no voltage is sensed on the bus by the first level/loss-of-voltage bus relays), the EDG output breaker will close to supply power to the bus, and the associated plant loads (ESF equipment) will be sequenced onto the re-energized bus by the associated delay timers, as described above.

For a postulated event in which the LOOP precedes the LOCA (SI initiation), availability of the EDG cannot be entirely assured. As described earlier, occurrence of the LOOP will cause a significant drop in bus voltage and a large increase in EDG output current that results in a trip of the main or reserve feed breaker from either the first-level undervoltage relays or the voltage-restrained overcurrent relays. Tripping these breakers removes the overload or the effect of the fault from the offsite source and allows the EDG to supply power to its safety-related bus. However, availability of the EDG is dependent on the timing of the LOCA signal following the LOOP and on whether the main or reserve feed breaker is tripped by the undervoltage relay or the voltage-restrained overcurrent relays. In particular, the timing of these relays relative to the timing of time-delay (sequencing) relays that control the closing of the feed breakers for certain large ESF motors (i.e., the shutdown service water (SX) system pump motors) can cause EDG loading to occur differently than anticipated for licensing basis events. This process is described further as follows.

In the event of a bus undervoltage relay trip, the time delay relay in the closing circuit for the SX system pump motor breaker will drop out and reset. At the same time, the non-safety service water (WS) system pumps that normally supply cooling water to the safety-related loads will trip on the LOOP, thereby causing a loss of WS pressure. A pressure switch in the WS piping header for each SX division will then sense the low WS pressure and initiate a start signal to the respective SX pump motor breaker. Once the EDG restores bus voltage, and after a 10-second time delay, the time delay relay energizes the closing coil of the SX pump motor breaker. In the event an SI initiation signal is received

concurrent with a LOOP, this logic sequence normally ensures delay of the start of the SX pump motor until after the start of other large ESF motors (in accordance with the intended load sequence for the associated EDG) but in sufficient time to provide cooling water for the EDG. Thus, the EDG remains available with a LOOP preceding a bus undervoltage relay trip with a LOCA initiation signal.

However, intended load sequencing for the EDG may not occur if the SX pump motor receives a start signal from the SX pressure switch before the SI initiation relay. In this particular scenario, the SX pump motor will start on low WS pressure exactly 10 seconds after its safety-related bus voltage is restored by the EDG, regardless of the SX pump start signal that may be received on a subsequent SI initiation signal. Thus, if the SI initiation signal occurs at approximately the same time that the time-delay relay energizes the breaker closing coil of the SX pump motor, the SX pump motor and a large ESF motor will start simultaneously and may cause the EDG to trip on overload because of the high motor starting currents. On the other hand, if the SI initiation signal is received 5 seconds after the SX time delay relay times out, sequencing of the ESF loads with the SX pump motor will not be simultaneous and the EDG will not be overloaded.

In response to a voltage-restrained overcurrent relay trip, the EDG will restore bus voltage before the undervoltage relay trip. Consequently, the time delay relay in the closing circuit for the SX pump motor breaker remains energized, thereby allowing the breaker to close without delay once the WS low-pressure switch start signal is received for the SX pump motor. If the SI signal occurs at approximately the same time as the overcurrent relay trip, the SX pump motor may start simultaneously with the start of the ESF equipment and could cause the EDG to trip on overload (as in the above scenario). On the other hand, if the LOCA initiation signal is received more than 5 seconds after the voltage-restrained overcurrent relay trip, sequencing of ESF equipment will occur after the SX pump motor has already started and the EDG will not be overloaded.

On the basis of this information, the EDG may be rendered unavailable only under a particular sequence of events in which the EDG is in the test mode when a LOOP event occurs, causing a trip of the voltage-restrained overcurrent relay before the undervoltage relay, followed shortly by a LOCA initiation. This postulated event is an event of extremely low probability (9.48 E-8/year) and, therefore, can be excluded as a potential contributor to EDG unavailability. Further, the above-described sequence can only occur for an EDG being tested. Since only one EDG is tested at a time, the remaining divisions powered by the other EDGs would not be affected.

In response to the staff's concern regarding plans for restricting additional maintenance or testing of required safety systems, subsystems, trains, components, and devices that depend on the remaining EDGs as a source of emergency power, the licensee stated that the TS

themselves impose requirements and restrictions on the required equipment and features associated with the redundant division (i.e., the division associated with the EDG not being tested) when an EDG is inoperable (including being made inoperable for testing or maintenance). Specifically, when an EDG becomes inoperable in Mode 1, 2, or 3, Required Action B.2 of TS 3.8.1, "AC Sources - Operating," requires identification of inoperable required features that are redundant to required features supported by the inoperable EDG. This required action is applicable throughout the entire period of diesel inoperability. Inoperable features on the redundant division can then cause entry into other or more severe required actions, thus providing further incentive not to make an EDG inoperable whenever a required feature on the redundant division is inoperable. Required Action B.2 is intended to provide assurance that the occurrence of a LOOP, during the period that an EDG is inoperable, does not result in a complete loss of safety function of critical systems.

The Safety Function Determination Program, pursuant to TS 5.5.10 is used to ensure that there is no loss of a safety function as a result of removing equipment from service for maintenance or testing with regard to the relationship between support and supported systems or functions as addressed by TS Limiting Condition for Operation (LCO) 3.0.6.

Additionally, on-line scheduling and coordination of work activities at CPS is procedurally controlled through CPS 1151.01, "On-Line Work Management Process." This procedure links the steps of the work control process, including assessing on-line risk consistent with the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (i.e., the maintenance rule). CPS Procedure 1151.12, "On-line Risk Assessment," governs the process for assessing on-line risk. The identified purposes of this procedure include outlining the requirements for assessing, monitoring, and maintaining acceptable levels of on-line risk; outlining requirements for performing reviews and evaluations of work schedules before implementation; and providing guidance to determine the safety implications of removing equipment from service for performance of on-line maintenance as required by 10 CFR 50.65.

On-line risk assessment ensures that defense in depth is provided for the duration of the on-line maintenance. This assessment includes a detailed examination of the on-line maintenance schedule, including system interactions, support system availability, and the impact of temporarily installed equipment.

To address the concern of whether there are plans for restricting additional maintenance or testing of required safety systems, subsystems, trains, components, and devices that depend on the remaining EDG as a source of emergency power, CPS 1151.12 contains provisions for assessing risk levels. One of these provisions is to use risk assessment tools (i.e., a risk meter) to analyze on-line risk. These tools are used to identify the level of risk associated with the scheduled activities. Green (minimal), yellow (acceptable), orange (high), and red (unacceptable) risk levels are defined in CPS 1151.12. In accordance with the procedure, consideration should be given to the risk level in determining when to perform the activities.

Regarding switchyard activity during EDG online testing, the licensee stated that CPS 1151.12 contains specific provisions for assessing activities occurring in the switchyard that increase the potential for a LOOP or a loss-of-power to the RAT to occur. Further, consideration is given to

changing the risk levels to the next higher category when conditions exist that could cause the plant to be at higher risk levels, such as, tornado watches or warnings, severe thunderstorm watches or warnings, a 345-kV line out of service, or work being performed on one of the lines. The results of the CPS on-line risk assessment may identify that if the risk level is high enough, contingency plans need to be established to maintain on-line safety at an acceptable level, or that the activities need to be rescheduled if unacceptable levels are identified.

In response to the staff's question regarding the typical and worst case voltage transients on the medium-voltage safety bus as a result of a full-load rejection, the licensee stated that the perturbation on the medium-voltage safety bus during an EDG full-load rejection test would be nearly proportional in magnitude to the voltage peaks on the 4-kV safety bus. Using data taken from past full-load rejection tests that were performed before installation of the SVCs, the initial voltage dip on the 4-kV bus ranged from a minimum of 59 volts (1.4 percent of nominal) during a Division 2 EDG test in July 1998, to a maximum of 341 volts (8.1 percent of nominal) during a Division 3 EDG test in November 1996. On the basis of this actual test data, the initial voltage dips for the medium-voltage buses would range between 2 and 10 volts at the 120-V level, and between 7 and 39 volts at the 480-V level. Voltage on the medium-voltage safety buses during testing would thus remain above the minimum required transient voltage for plant loads and would stabilize shortly after the disturbance (i.e., in less than 2 seconds, consistent with the voltage stabilization observed on the 4-kV bus). The voltage transient experienced by the loads on the 4-kV, 480-V and 120-V buses during EDG full-load rejection testing is therefore minor.

Furthermore, voltage perturbations are further minimized because of the compensating effect of the SVC. With the SVC controlling, the bus voltage quickly recovers to the voltage setpoint of the SVC. This compensating effect was demonstrated in a recent full-load rejection test on the Division 3 EDG with the SVC in service, when the transient voltage dip was only 35 volts on the 4- kV bus, and the bus voltage recovered to the SVC setpoint voltage in 0.4 second.

The staff has reviewed the information provided by the licensee, and for the reasons described above, the staff concludes that it is acceptable to perform the requested EDG SRs at power.

4.0 RISK EVALUATION

The staff evaluated whether the proposed changes would have a significant risk impact. The staff made two inquiries with respect to risk: (1) How likely is it that the proposed testing at power would cause a plant transient challenging the safety systems? (2) Would the risk impact from the increase in the EDG unavailability be significant? The licensee's original application and its response of August 8, 2000, to the staff's request for additional information addressed these questions.

The transient initiating event of concern relevant to the proposed EDG testing at power is the potential LOOP. The licensee indicated that the proposed surveillance tests at power would have a very small likelihood of resulting in a significant voltage perturbation. The licensee's test data and their technical basis support the justification. According to the licensee, the duration of time for which the EDG in test is unavailable would be very small for each surveillance test being proposed. This situation would result in a negligible increase in EDG unavailability. The licensee found the quantitative risk of the proposed changes to be much below the staff

guidelines in the applicable Regulatory Guide (RG) 1.177. The staff finds the licensee's justification for the small risk impact to be reasonable.

The licensee has TS requirements that impose restrictions on the required features that are redundant to those supported by the inoperable EDG. In addition, the licensee has a procedurally controlled on-line work management process that performs risk assessment for work activities at power. The process governing on-line risk assessment also provides the guidance to determine the safety implications of removing equipment from service for performance of on-line maintenance as required by the maintenance rule, 10 CFR 50.65. The staff finds that the licensee has a process in place, consistent with the maintenance rule, that evaluates the risk associated with taking equipment out of service. This proceduralized process is consistent with the guidance of the configurational risk management programs set forth in RG 1.177 for risk-informed TS changes.

In summary, the staff finds that the licensee demonstrated that the proposed on-line surveillance testing of EDGs would have a very small likelihood of causing a plant transient and that it would also result in a negligible increase in EDG unavailability. Therefore, the staff believes that the risk implications of the proposed changes would be insignificant. In addition, the licensee has a configurational risk assessment process, consistent with the maintenance rule, that controls work activities at power using risk insights. In conclusion, the staff finds that risk insights and findings support the proposed changes.

5.0 FINDING

The staff has reviewed the proposed amendment to remove the mode restrictions from SRs 3.8.1.9, 3.8.1.10, 3.8.1.13, 3.8.1.14, and 3.8.1.17 from a deterministic and a probabilistic risk assessment perspective. We conclude that the deterministic and available risk insights and findings support the proposed change. Therefore, the proposed amendment is acceptable.

6.0 STATE CONSULTATION

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

7.0 ENVIRONMENTAL CONSIDERATION

This amendment changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding (65 FR 46006). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

8.0 CONCLUSION

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

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