Entergy

Indian Point Energy Center
450 Broadway, GSB
P.O. Box 249
Buchanan, N.Y. 10511-0249
Tel (914) 734-6700

J.E. Pollock
Site Vice President
Administration

September 29, 2008

Re: Indian Point Units 2
Docket Nos. 50-247

NL-08-139

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

SUBJECT: **Reply to Request for Additional Information Regarding Indian Point Unit 2 Proposed Changes to Technical Specifications Regarding Diesel Generator Endurance Test Surveillance (TAC NO.MD9214)**

References:
1. NRC Letter dated September 5, 2008 "Request for Additional Information Regarding Amendment Application for Revision to Diesel Generator Surveillance Test (TAC NO.MD9214)
2. Entergy letter NL-08-101 dated July 9, 2008 regarding "Proposed Changes to Indian Point 2 Technical Specifications Regarding Diesel Generator Endurance Test Surveillance"

Dear Sir or Madam:

Entergy Nuclear Operations, Inc (Entergy) is providing the additional information requested in Reference 1 regarding the NRC request for additional information associated with the Proposed Changes to Indian Point 2 Technical Specifications Regarding Diesel Generator Endurance Test Surveillance submitted in Reference 2. The responses to the additional information requested are provided in Attachment 1.

Attachment 2 to this letter provides an updated analysis of the proposed technical specification changes regarding diesel generator endurance test surveillance originally provided in Reference 2; there is no change to the no significant hazards consideration provided in Reference 2, Attachment 3 iprovides an updated markup of the technical specification pages for the proposed change. Finally, Enclosure 1 provides copies of the Emergency Operating Procedures referenced in the diesel load studies in response to Question 8 of Reference 1. Entergy has concluded that the proposed changes to original submittal of the amendment to the

A001

NRR

Indian Point 2 Technical Specifications presents no change to the significant hazards consideration evaluation.

There are no new commitments identified in this submittal. If you have any questions or require additional information, please contact Mr. R. Walpole, Manager, Licensing at (914) 734-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on September 29, 2008.

Sincerely,

J. E. Pollock
Site Vice President
Indian Point Energy Center

Attachment: 1. Reply to NRC Request for Additional Information Regarding Proposed Changes to Indian Point 2 Technical Specifications Regarding Diesel Generator Endurance Test Surveillance (TAC NO.MD9214)

2. Updated Analysis of Proposed Technical Specification Changes Regarding Diesel Generator Endurance Test Surveillance (Formerly Attachment 1 to NL-08-101)

3. Updated Markup of Technical Specification page for Proposed Changes Regarding Diesel Generator Endurance Test Surveillance (Formerly Attachments 2 and 3 of NL-08-101)

Enclosure: 1. Copy of Emergency Operating Procedures (EOP) Referenced in Diesel Load Studies in Response to Question 8 of Request for Additional Information.

cc: Mr. John P. Boska, Senior Project Manager, NRC NRR
Mr. Samuel J. Collins, Regional Administrator, NRC Region I
NRC Senior Resident Inspectors Office
Mr. Paul Eddy, New York State Dept. of Public Service

ATTACHMENT 1 TO NL-08-139

REPLY TO NRC REQUEST FOR ADDITIONAL INFORMATION

REGARDING

PROPOSED CHANGES TO INDIAN POINT 2 TECHNICAL SPECIFICATIONS

REGARDING DIESEL GENERATOR ENDURANCE TEST SURVEILLANCE

(TAC NO.MD9214)

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET No. 50-247

Response To Request For Additional Information

By letter dated July 9, 2008, Agency wide Documents Access and Management System Accession No. ML0819800160, Entergy Nuclear Operations, Inc. (Entergy or the Licensee) requested an amendment to the Technical Specifications (TS), Appendix A of Facility Operating License No. DPR-26 for Indian Point Nuclear Generating Unit No. 2. The proposed change would revise the test acceptance criteria specified in TS Surveillance Requirement (SR) 3.8.1.10 for the diesel generator endurance test surveillance. The licensee has proposed revising the load ranges and the power factors specified for the endurance test for consistency with the associated plant safety analyses. The Nuclear Regulatory Commission (NRC) staff is reviewing the submittal and has the following questions:

Question 1

Section 5.1.5, "Miscellaneous Losses," of WCAP-12655, Revision 2, "Emergency Diesel Generator Loading Study for Indian Point Unit 2," indicates that frequency fluctuations impact up to 0.5% (60 hertz (Hz) +/- 0.3 Hz), which add 1.5% (or 35 kilo watts (kW) at the 2300 kW rating. Indian Point, Unit 2, TS SRs 3.8.1.2, 3.8.1.12, and 3.8.1.13 allows frequency variations up to +/-2% and voltage variation between 428 and 500 volts. Explain (1) the discrepancy between the TS allowable frequency variation and the assumed frequency impact in WCAP-12655, Revision 2, and (2) the ability of the diesel generator to adequately perform its design function while loaded under the worst-case frequency scenario (i.e., frequency variation of +2%). Also provide assurance that the diesel generator can perform its design function while loaded during the worst-case voltage scenario (i.e., 428 volts minimum or 500 volts maximum), as identified in TS SRs 3.8.1.2, 3.8.1.12, and 3.8.1.13.

Response

The discrepancy with TS allowable frequency variation was noted in responses to Condition Report IP2-2006-06850, and a separate license amendment request (LAR) is being processed to address required TS changes. Administrative controls are in place for this issue. Surveillance procedures have been changed to specify an acceptance criteria of +/- 0.3 Hz (+/- 0.5 %), and the diesel generators' design function is adequately maintained as the TS change is being prepared. (Reference procedures; 2-PT-M021A/ B/ C and 2-PT-R084A/ B/ C). Voltage operating range of 428V to 500V is based on EDG running in parallel Mode. During Unit Mode operation maximum voltage regulation is .5% (2.4V). This variation will have relatively no effect on the EDG or running motor loads performance.

Question 2

In response to the licensee's response to Question 1a provided in its July 9, 2008, license amendment request, the licensee provided details on the diesel generator and switchgear capabilities. The NRC staff found that the switchgear ampere rating associated with the output breaker of the diesel generator does not envelop the diesel generator load profile for the large break loss of coolant accident (LOCA) as specified in WCAP-12655, Revision 2, dated June 2002. Specifically, the executive summary of the switchgear analysis noted that the switchgear was analyzed to determine the worst case loading scenario of 1750 kW continuous followed by operation at 2300 kW for ½ hour followed by 2100 kW for 2 hours. However, the actual load profile for a large break LOCA is 2100 kW for approximately ½ hour followed by 2300 kW for a short period of time followed by 1750 kW continuous. It is the NRC staff's expectation that the diesel generator endurance run test load profile must envelop the design basis assumptions (i.e., the worst case load profile) for the nuclear power plant.

Furthermore, the licensee has proposed adding new Note A in TS Bases Section 3.8.1, "AC Sources – Operating," that specifically states that operation at the overload ratings is allowed only for ≤ 2300 kW (1/2-hour) followed by ≤ 2100 kW (2-hour), not vice versa. Based on the diesel generator loading study for Indian Point Unit 2 (WCAP-12655, Revision 2), the peak load (approximately 2300 kW) can occur any time during the LOCA scenario depending upon the size of break (approximately 40 minutes in case of a large break LOCA and approximately 120 minutes in case of a small break LOCA). The diesel generator and the associated switchgear must be capable of supplying the peak load at any time (i.e., loading order should not be a factor) during either LOCA scenario.

Given the limitation on the switchgear rating, provide the technical basis to ensure that the diesel generator and the switchgear associated with the output breaker of the diesel generator will perform their design function during the postulated LOCA scenarios.

Response

Based on discussions with NRC staff, the load sequencing testing has been altered as follows:

Verify each DG operating at a power factor ***as stated in Note 3*** operates for ≥ 8 hours as follows:

a. For ≥ 105 minutes and ≤ 2 hours loaded to ≥ 2050 kW and ≤ 2100 kW, followed by

b. For ≥ 10 minutes and ≤ 15 minutes loaded to ≥ 2270 kW and ≤ 2300 kW, followed by

c. For the remaining hours of the test loaded to ≥ 1700 kW and ≤ 1750 kW.

As requested the surveillance testing load profiles changes are noted in attachment 2 and 3 (previously Attachments 1, 2 and 3 of NL-08-101).

Additionally, acceptance of previously performed (2R18, spring 2008) surveillance test using the load profile in NL-08-101 is requested as satisfaction of tech spec surveillance requirement 3.8.1.10 until the next regularly scheduled performance of this surveillance test (scheduled during 2R19, spring 2010). This testing sequence does not meet the sequence now submitted but is considered acceptable for this surveillance interval.

Question 3

> Table 6.1-2c of the Indian Point Unit 2 diesel generator loading study indicates that Charging Pump 23 will start 118 minutes into a small break LOCA. Describe how you have analyzed the capability of the diesel generator and switchgear to handle starting of the large motor load, which can draw starting current close to six times full load current, 118 minutes into a small break LOCA event when the diesel generator is pre-loaded close to its 2-hour rating and the switchgear is also pre-loaded close to its full continuous ampere rating.

Response

Transient and load sequencing scenarios for the diesel generators were analyzed using PTI software program PSS/E under calculation FEX-00083-00, "Dynamic Loading of Emergency Diesel Generators". Motor starting and diesel generator response were both determined to be acceptable with initial loading close to the EDG short time ratings. In Table 6.1-2c of the loading study, the starting motor at 118 minutes should be CCW Pump 23, not Charging Pump 23. The correct load sequence is shown in Table 6.1-1, and the kW value shown in Table 6.1-2c is actually the load of the CCW pump. This appears to be a transposing error only, and the calculation shows the correct total kW for the load sequence. Condition report IP2-2008-04243 was generated to correct the table description.

Ampere loading on the switchgear was addressed in testing performed by Satin American. While testing did not consider motor starting, a step change in current for such short durations as the seconds required for motor start would have a negligible affect on bus or switchgear temperature rise. Various test curves in Calculation EGE-00006-00 (Attachment 4, Enclosure 1 of July 9, 2008 letter) show step changes in current of up to 3400 amperes, but the resulting temperature rise on components requires minutes for any appreciable change. The effects of motor starting on temperature rise in bus and switchgear is considered negligible.

Question 4

> Table 6.1-2c of the Indian Point Unit 2 diesel generator loading study indicates that the maximum expected kW for Charging Pump 23 is 150 kW. However, Table 6.1-2c indicates that Charging Pump 23 would add 213 kW 118 minutes into a small break LOCA event. Explain the discrepancy between these two values.

Response

Response provided in Question 3. (The starting motor at 118 minutes should be CCW Pump 23, not Charging Pump 23.)

Question 5

> In Attachment 4, Enclosure 1, of its July 9, 2008, license amendment request, the licensee indicated that the switchgear associated with the output breaker of the diesel generator was modified by changing the bus transition from aluminum to copper and the switchgear ventilation scheme. Describe the impact of the

design changes on the qualification of the entire switchgear associated with the output breaker of the diesel generator.

Response

Changes were evaluated under Safety Evaluations 90-408-DE and 91-067-MM for the replacement bus sections and switchgear louvers, respectively. Changes were determined to be acceptable, with no impact to qualification of equipment.

Question 6

The diesel generator loading study appears to only consider kW losses. Since kilovolt ampere reactive (kVAR) losses will increase the current that the switchgear has to handle, describe how kVAR losses were considered when analyzing the diesel generator loading.

Response

The diesel generator loading study only considers kW losses, since the study itself is limited to determining kW loads on each diesel (not kVA or kVAR). An evaluation of power factor and kVAR loads was performed in response to a condition report (Attachment 4, Enclosure 8 of July 9, 2008 letter), with the intent of determining total kVA loading on each diesel generator. The evaluation considered major loads which are greater than 50kW, and calculated the equivalent kVA and kVAR loading along with overall power factor. Calculated worst case loading power factors were determined to be 0.87 – 0.88, whereas the generator ratings are 2300kW at 0.8 pf. The margin between calculated load power factor (>0.87) and rated power factor (0.80) is considered adequate to account for kVAR losses in the system.

Loading effects on switchgear and bus due to the increased amperes and temperatures associated with VAR loading were considered under the testing performed by Satin American (calculation EGE-00006-00). Testing considered ampere loading up to 3400 amps to provide margin above the actual predicted loads. Considering that the calculated worst case power factor is 0.87, the equivalent ampere load at 2300kW and rated voltage is 3180 amps. Testing at 3400 amps provides a margin of 220 amps, which is considered adequate for VAR losses.

Based on further discussion of this question with the NRC, additional information has been requested related to verification of the effects of power factor (pf) on all loading connected to the EDG, including cabling and the transformer inductance. This additional information will be provided in a subsequent submittal.

Question 7

As a result of our review of the diesel generator loading study, it does not appear that all automatic loads have been considered (e.g., Table 3.4-2 of the diesel generator loading study identifies the following automatic loads under Motor Control Center 27A: Plant vent sample station compressor and Fuel Storage Building Exhaust Fan, that do not appear on the diesel generator load tables for either the large break LOCA or the small break LOCA). Explain why these automatic loads are not included on the diesel generator loading tables.

Response

The two loads in question for MCC 27A are actually manually controlled loads in accordance with their schematic drawings (207637, 9321-3127 Sheet 4); therefore these loads should not be included in the loading tables. Condition report IP2-2008-04243 has been generated to address this discrepancy in the calculation.

Question 8

Describe how the manual action assumptions credited in the diesel generator loading study were evaluated, e.g., manual loading of the charging pump within the first minute of a large break LOCA, and shedding of loads (especially, the motor-driven auxiliary feedwater pump at 30 minutes) following the onset of a large break LOCA. Also, describe the cues and procedures that would direct the control room operator to reduce diesel generator loading during a large break LOCA. Additionally, provide a copy of the involved procedures.

Response

Manual operator action assumptions, and the loads considered in the various scenario spreadsheets, are based on Emergency Operations Procedures (EOPs) as indicated in Section 4.2 and throughout Sections 5, 6, and 7 of the loading study. Operators are also cautioned not to exceed diesel loading limits in the EOPs (e.g. ECA-0.0 prior to Step 5, *"The load on the diesel generators should remain less than 1650 kW but may be increased to 2000 kW for a maximum of 2 hrs in any 24 hr period."*).

The complete list of EOPs referenced in the load study is provided in the table below,

EOP Number	EOP Title	Revision No.
E-0	Reactor Trip or Safety Injection	38
ES-0.0	Rediagnosis	34
ES-0.1	Reactor Trip Response Natural Circulation	36
ES-0.2	Cooldown Natural Circulation	34
ES-0.3	Cooldown with Steam Void in Vessel (with RVLIS) Natural Circulation	34
ES-0.4	Cooldown with Steam Void in Vessel (without RVLIS)	34
E-1	Loss of Reactor Coolant	36
ES-1.1	SI Termination	36
ES-1.2	Post LOCA Cooldown and Depressurization	36
ES-1.3	Transfer to Cold Leg Recirculation	36
ES-1.4	Transfer to Hot Leg Recirculation	36

E-2	Faulted Steam Generator Isolation	34
E-3	Steam Generator Tube Rupture	36
ES-3.1	Post SGTR Cooldown Using Backfill	34
ES-3.2	Post SGTR Cooldown Using Blowdown	34
ES-3.3	Post SGTR Cooldown Using Steam Dump	34
ECA-0.0	Loss of all AC Power	37
ECA-0.1	Loss of all AC Power Recovery without SI Required	34
ECA-0.2	Loss of all AC Power Recovery with SI Required	34
ECA-1.1	Loss of Emergency Coolant Recirculation	34

Question 9

With regard to General Electric (GE) Report DER-1691, dated October 13, 1989, (Attachment 4, Enclosure 4 to NL-08-101), confirm that all changes required for the long-term solution (listed in Section V(B)) were implemented.

Response

Changes recommended by GE Report DER-1691 were implemented by Modification MMM-89-03369-P, with additional supporting modifications EGP-90-03369-R, CPC-89-03369-H, and EGP-89-03369-E. These changes were originally reviewed and accepted by the NRC in an amendment dated May 9, 1991 (TAC No. 76009).

Question 10

Report DER-1691 states that if all of the changes required for the long-term solution are implemented, the engine output will be:

1750 kW continuous
1950 kW 6000 hrs/yr
2150 kW 3000 hrs/yr
2205 kW 1000 hrs/yr

Westinghouse Engineering Report WMC-EER-90-005, dated September 19, 1990, (Attachment 4, Enclosure 5 to NL-08-01) states that in 1984 Westinghouse did an engineering study that concluded that the diesel generators were capable of delivering 2250 kW continuously. The conclusion of the report (WMC-EER-90-005) is that the diesel generators are capable of delivering 2300 kW continuously.

Describe any further modifications that were implemented in order to have the diesel generator continuous rating increase from 1750 kW to 2250 kW in 1984 and from 1750 kW in 1989 to 2300 kW in 1990.

Response

Diesel generator sets at Unit 2 are GE/ALCO diesel engines with Westinghouse generators. DER-1691 (performed by GE) presented an evaluation on diesel engine performance and the diesel supporting systems, but did not address generator performance.

WMC-EER-90-005 evaluated the generator itself, and determined that the generator is capable of continuous operation at 2300kW. No modifications were done to get to this rating. This was a re-evaluation of the 1984 study, taking credit for tests performed on 1750 kW machines. This study applies to the generator only, not the engine.

Question 11

Calculation IP-CALC-06-00281, "Ventilation System for the EDG Building," is part of Calculation EGE-00016-00 (Attachment 4, Enclosure 6 to NL-08-101). In section 6.7.2 of Calculation IP-CALC-06-00281 it is stated that the total diesel generator building air flow is the sum of the air flow from the operating fans added to the air flow required for combustion. If the engine air inlet is piped to the outside, as required by GE Report DER-1691, then explain why the combustion air flow is added to the sum of the air flow from the operating fans to determine the room temperature rise.

If the engine air inlet is not piped to the outside, then the air drawn into the building for combustion does not travel from one side of the building to the other and exit the building through the exhaust fans. Explain why the combustion air should be added to the air flow from the operating fans to determine the room temperature rise.

Response

The Unit 2 EDG building modification to pipe the engine combustion (inlet) air to the outside was never completed. The engines still draw their required combustion air from outside the building through the inlet louvers and into the building. This air flow is generated by the engines themselves and is over and above the airflow drawn into the building by the EDG building HVAC fans.

As the combustion air is drawn to the engine intakes it will heat up due to the higher temperature within the building. The air temperature entering the engine inlets will be higher than the outside air temperature and this delta T actually removes some of the internally generated heat inside the building. It doesn't matter when determining the room temperature if the air is discharged out of the building or it enters the engine. The total temperature rise of the air within the room is determined by the total heat generated inside the room and the total air flow into the room along with the air properties of specific heat and density.

ATTACHMENT 2 TO NL-08-139

UPDATED ANALYSIS OF PROPOSED TECHNICAL SPECIFICATION CHANGES

REGARDING

DIESEL GENERATOR ENDURANCE TEST SURVEILLANCE
(Formerly Attachment 1 to NL-08-101)

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

1.0 DESCRIPTION

Entergy Nuclear Operations, Inc (Entergy) is requesting an amendment to Operating License DPR-26, Docket No. 50-247 for Indian Point Nuclear Generating Unit No. 2 (IP2). The proposed change will revise the test acceptance criteria specified in SR 3.8.1.10 for the Diesel Generator endurance run surveillance. Changes in the load ranges and power factors specified for the test are proposed for consistency with the associated safety analyses. The proposed changes are the result of corrective actions taken by Entergy to address NRC inspection results reported in Reference 1.

The specific proposed changes are listed in the following section.

2.0 PROPOSED CHANGES

The surveillance test acceptance criteria in Diesel Generator Surveillance SR 3.8.1.10 will be revised as follows:

A. The required **load ranges** will be changed as follows:

FROM:

a. For ≥ 2 hours loaded ≥ 1837 kW and ≤ 1925 kW and
b. For the remaining hours of the test loaded ≥ 1575 kW and ≤ 1750 kW.

TO:

a. For ≥ 105 minutes and ≤ 2 hours loaded ≥ 2050 kW and ≤ 2100 kW, followed by
b. For ≥ 10 minutes and ≤ 15 minutes loaded ≥ 2270 kW and ≤ 2300 kW, followed by
c. For the remaining hours of the test loaded ≥ 1700 kW and ≤ 1750 KW.

B. The **power factor** limits will be changed as follows:

FROM:

≤ 0.85 (applicable for all three DGs)

TO:

≤ 0.88 (applicable to DGs 21 and 23)
≤ 0.87 (applicable to DG 22)

The Technical Specification markup pages and the Bases changes needed to reflect these proposed new test values are found in Attachment 3.

3.0 BACKGROUND

3.1 Load Range

IP2 Improved Technical Specification (ITS) surveillance SR 3.8.1.10 is a test of the emergency diesel generators, similar to Standard Technical Specification (STS, Reference 2) surveillance SR 3.8.1.14. This surveillance requires that each DG be started and loaded for a specified period of time at specified loading conditions, which include kilowatt (kW) output and power factor. Prior to conversion to ITS, the IP2 Custom Technical Specifications (CTS) contained a requirement for diesel testing (Specification 4.6.A.2) which stated:

"At each Refueling Interval (R###), each diesel shall be manually started, synchronized and loaded up to its continuous (nameplate) and short term ratings."

The CTS Bases stated:

"Each diesel is rated for operation for 0.5 hours of operation out of any 24 hours at 2300 kW plus 2.0 hours of operation out of any 24 hours at 2100 kW with the remaining 21.5 hours of operation out of any twenty four hours at 1750 kW."

This CTS testing requirement was established in IP2 License Amendment 153 (Reference 3) which reflected the installation of a plant modification designed to provide for an increase in the DG short-term rating.

During the conversion to ITS for IP2 (Reference 4), the CTS requirement was expanded to specify test acceptance criteria in the technical specification surveillance; acceptance criteria for test duration and power factor were added. In addition, the loading requirement for this test was modified to specify two test intervals; one at a load range that corresponds to 90% - 100% of the DG continuous rating and the other at a load range that corresponds to 105% - 110% of the DG continuous rating.

During NRC inspection activities described in Reference 1, questions were raised regarding the adequacy of the load ranges specified in ITS SR 3.8.1.10 to demonstrate the capability of the DGs to operate at the peak loading conditions identified in plant safety analyses for the limiting design basis accident (DBA). As a result Entergy acknowledged the need to submit a license amendment request to establish new load ranges that would bound the peak accident loads. Entergy has verified that the proposed new load ranges bound the peak accident loads. The values for the peak accident loads are included on Table One, which provides a comparison of the various DG loading values discussed in this section.

3.2 Power Factor

While investigating the above changes regarding DG kW loading, Entergy also determined that a change to the power factor test value is also appropriate. At IP2, the emergency diesel generator and associated electrical distribution system is a 480 volt system. Surveillance testing cannot be performed using the 480 V loads that would be powered under an accident scenario; rather the

TABLE ONE
COMPARISON OF VARIOUS DIESEL GENERATOR LOADING VALUES

DG Rating (Note A)	Continuous Rating 1750 kW	120-Minute Rating 2100 kW	30-Min Rating 2300 kW
Peak DG Loading for limiting DBA	DG 22 2076 kW	DG 23 2194 kW	DG 21 2268 kW
Existing SR 3.8.1.10	≥ 1575kW to ≤ 1750 kW For the remaining hours of the ≥ 8-hour test (= 90% - 100% of Continuous Rating)	≥ 1837kW to ≤ 1925 kW For ≥ 2 hours (= 105% - 110% of Continuous Rating)	
Proposed new SR	≥ 1700 kW to ≤ 1750 kW For the remaining hours of the ≥ 8-hour test	≥ 2050 kW to ≤ 2100 kW Start Test ≥105 to ≤120 min	≥ 2270 kW to ≤ 2300 kW Followed by ≥10 to ≤ 15 min

Kw scale 1500kw 1575 1650 1725 1800 1875 1950 2025 2100 2175 2250 2325

Note A: These rating are based on limitations imposed on the diesel engine, circuit breaker, and bus portions of the DG which are more limiting then the rating of the generator portion of the DG, which is rated for continuous operation at 2875 KVa.

loading of the DG must be accomplished by picking up load from the offsite grid. This involves step-up transformers from 480 V to 6.9 kV and then additional step-up to either 13.8 kV or 138 kV, depending on which feeder circuits are available between the station and the grid. This testing configuration can make it difficult to establish a low power factor test configuration and maintain other electrical parameters within operational limits of the DG. As part of the review of the electrical loading study to address the kW limit issue, Entergy has determined that there is margin between the existing technical specification power factor test requirement and the analysis power factor for the limiting load scenarios. Therefore, the proposed change will eliminate unnecessary conservatism from the test and provide greater ability to perform the test without crediting the technical specification note regarding limitations on power factor caused by grid conditions.

4.0 TECHNICAL ANALYSIS

4.1 Load Range

The peak DG loading conditions reported in this LAR are based on the current version of the Indian Point 2 Emergency Diesel Generator Loading Study. The methodology consists of an evaluation of emergency safeguards equipment powered from the 480 Vac emergency safeguards bus under hypothetical accident scenarios which also involve loss of normal offsite power. The evaluation accounts for the time-dependent electrical power requirements of various safeguards components as the accident scenario progresses.

The evaluation concludes that the limiting loading condition occurs for the LBLOCA scenario during the time period when plant operators are implementing the recirculation switch sequencing activity that completes the transition from injection flow (refueling water storage tank via the safety injection pumps) to recirculation flow (recirculation sump via recirculation pumps). This activity occurs at approximately 40 minutes after the initiation of the accident sequence. In addition, the evaluation accounts for the single-failure of one of the DGs. The duration of the peak loading condition is limited to a few minutes, associated with the elapsed time between operator actuation of one switch (switch 4) that starts the required recirculation pump and operator actuation of another switch (switch 7) that secures the running safety injection pump. The resulting peak loading for each DG is as follows:

DG	Peak Load
21	2268 kW, with loss of DG 23
22	2076 kW, with loss of DG 23
23	2194 kW, with loss of DG 21

The peak loading conditions are bounded by the DG short-term (30-minute) rating limit of 2300 kW. The proposed new SR acceptance criterion of > 2270 kW to < 2300 kW for ≥ 10 to ≤ 15 minutes also bounds these peak loading conditions, without exceeding the DG 30-minute rating limit.

In addition to peak loading conditions, the load study evaluation considers the time dependent electrical power demands with respect to the other DG rating values. The evaluation concludes that the 2-hour rating and continuous rating limits for the DG bound the electrical requirements of the hypothetical accident scenarios and the proposed new SR acceptance criteria provide assurance that the DGs can perform at these rated limits.

4.2 Power Factor

The existing ITS SR acceptance criterion for power factor (≤ 0.85) was determined based on engineering judgment. Prior to ITS (CTS), a test acceptance criterion for power factor was not specified. During tests conducted since ITS implementation, it was determined that procedure limits set for certain DG operating parameters (e.g., generator field amps and output voltage) served as a constraint in some cases to consistently achieve the new power factor acceptance criterion. Therefore Entergy performed further engineering evaluations regarding power factor and procedure limits on DG operating parameters.

The evaluation accounted for peak loading conditions from the DG loading study discussed in Section 4.1 and information from motor data sheets for the safeguards equipment motors rated at ≥ 50 kW. Affected motors include those associated with the Service Water Pumps, Safety Injection Pumps, Residual Heat Removal Pumps, Recirculation Pumps, Component Cooling Pumps, Auxiliary Feedwater Pumps, and Containment Recirculation Fans. Loads smaller than 50 kW were not considered due to the negligible impact on the overall power factor. The evaluation concluded that the existing technical specification power factor test requirement is overly conservative with respect to the DG loading requirements under hypothetical accident scenarios. Therefore the proposed new values of ≤ 0.87 (for DG 22) and ≤0.88 (for DGs 21 and 23) are more appropriate test acceptance criteria.

Entergy has determined that these power factor values are achievable under the test conditions applicable for this surveillance, based on a review of past test results and recent implementation of procedure changes regarding generator operating limits to be used for this test.

5.0 <u>REGULATORY ANALYSIS</u>

5.1 <u>No Significant Hazards Consideration</u>

Entergy Nuclear Operations, Inc. (Entergy) has evaluated the safety significance of the proposed change to the Indian Point 2 Technical Specification that revises EDG load testing and power factor requirements. This proposed change has been evaluated according to the criteria of 10 CFR 50.92, "Issuance of Amendment". Entergy has determined that the subject change does not involve a Significant Hazards Consideration as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

No. The proposed change revises the acceptance criteria to be applied to an existing surveillance test of the facility emergency diesel generators (DGs). Performing a surveillance test is not an accident initiator and does not increase the probability of an accident occurring. The proposed new acceptance criteria will assure that the DGs are capable of carrying the peak electrical loading assumed in the various existing safety analyses which take credit for the operation of the DGs. Establishing acceptance criteria that bound existing analyses validates the related assumption used in those analyses regarding the capability of equipment to mitigate accident conditions. Therefore the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the change create the possibility of a new or different kind of accident from any accident previously evaluated?

No. The proposed change revises the test acceptance criteria for a specific performance test conducted on the existing DGs. The proposed change does not involve installation of new equipment or modification of existing equipment, so no new equipment failure modes are introduced. The proposed revision to the DG surveillance test acceptance criteria also is not a change to the way that the equipment or facility is operated and no new accident initiators are created. Therefore the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

No. The conduct of performance tests on safety-related plant equipment is a means of assuring that the equipment is capable of maintaining the margin of safety established in the safety analyses for the facility. The proposed change in the DG technical specification surveillance test acceptance criteria is consistent with values assumed in existing safety analyses and is consistent with the design rating of the DGs. Therefore the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment to the Indian Point 2 Technical Specifications presents no significant hazards consideration under the standards set forth in 10 CFR 50.92 (c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements / Criteria

General Design Criterion (GDC) 17; "Electric Power Systems" requires that onsite electric power systems have sufficient independence, capacity, capability, redundancy, and testability to ensure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents, assuming a single failure.

GDC 18; "Inspection and Testing of Electric Power Systems" requires that electric power systems important to safety be designed to permit appropriate periodic inspection and testing to assess the continuity of the systems and the condition of their components.

IP2 Final Safety Analysis Report (FSAR) section 8.1 describes how the requirements of GDC 17 and 18 are met at IP2. Also, Technical Specification section 3.8.1 contains testing requirements for the DGs.

Regulatory Guide 1.9, Revision 3 describes methods for meeting the above requirements based on NRC staff endorsement of IEEE Standard 387-1984, with exceptions as stated in the Regulatory Guide. Regulatory Position 2.2 describes various DG tests, including test 2.2.9 for the Endurance and Margin Test. The loading requirements for this test are specified as a percentage of the continuous rating of the DGs, and these load ranges (105% - 110% of continuous rating and 90% - 100% of continuous rating) are specified in the existing technical specification surveillance requirement (SR) 3.8.1.10.

IP2 License Amendment 153 established the current continuous and short-term ratings of the DGs. The Technical Specification in effect at that time (4.6.A.2) stated that at each refueling outage, each DG shall be manually started, synchronized and loaded up to its continuous and short term ratings. This testing requirement was implemented in plant surveillance procedures.

In the conversion to Improved Technical Specifications (Reference 4) Entergy adopted test ranges based on Regulatory Guide 1.9. However, these ranges do not bound the peak DBA loading. Therefore, Entergy is proposing to revise the test load ranges specified for SR 3.8.1.10 based on the continuous and short term ratings defined in License Amendment 153. Testing at these ranges will assure that applicable criteria are met.

5.3 Environmental Considerations

The proposed changes to the IP2 Technical Specifications do not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

6.0 PRECEDENCE

IP2 License Amendment 153 established requirements for testing the DGs at the continuous and short term ratings.

7.0 REFERENCES

1. NRC Inspection Report 05000247 / 2006-003, dated August 11, 2006. (NCV 2006-003-05 and -08)

2. Standard Technical Specifications for Westinghouse plants, NUREG 1431.

3. NRC letter to Consolidated Edison Company; "Issuance of Amendment 153 for Indian Point Nuclear Generating Unit 2," dated May 9, 1991.

4. NRC letter to Entergy; regarding issuance of Amendment 238 for Indian Point Nuclear Generating Unit 2, dated November 21, 2003.

ATTACHMENT 3 TO NL-08-139

UPDATED MARKUP OF TECHNICAL SPECIFICATION PAGE FOR PROPOSED CHANGES REGARDING DIESEL GENERATOR ENDURANCE TEST SURVEILLANCE AND PROPOSED CHANGES TO TECHNICAL SPECIFICATION BASES SECTION 3.8.1 REGARDING DIESEL GENERATOR ENDURANCE TEST SURVEILLANCE

(Formerly ATTACHMENT 2 and 3 TO NL-08-101)

Affected Page: 3.8.1-8 Amendment 238

Changes from original submittal highlighted with final version requested

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET NO. 50-247

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.10	-- - NOTES - 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This SR shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. 3. If performed with DG synchronized with offsite power, it shall be performed at a power factor ***of ≤ 0.88 for DG 21, ≤ 0.87 for DG 22, and ≤ 0.88 for DG 23*** ~~≤ 0.85~~. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable. --	24 months
INSERT A	Verify each DG operating at a power factor ***as stated in Note 3*** ~~≤ 0.85~~ operates for ≥ 8 hours: a. For ≥ 2 hours loaded ≥ 1837 kW and ≤ 1925 kW and b. For the remaining hours of the test loaded ≥ 1575 kW and ≤ 1750 kW.	
SR 3.8.1.11	-- - NOTE - Load sequence timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. -- Verify each load sequence timer relay functions within the required design interval.	24 months

INSERT A, for SR 3.8.1.10

a. For $\geq$ 105 minutes and $\leq$ 2 hours loaded $\geq$ 2050 kW and $\leq$ 2100 kW, followed by

b. For $\geq$ 10 minutes and $\leq$ 15 minutes loaded $\geq$ 2270 kW and $\leq$ 2300 kW, followed by

c. For the remaining hours of the test loaded $\geq$ 1700 kW and $\leq$ 1750 kW.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The unit AC Electrical Power Distribution System AC sources consist of the following: two offsite circuits (a 138 kV circuit and a 13.8 kV circuit), each of which has a preferred and backup feeder; and, the onsite standby power circuit consisting of three diesel generators. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The plant distribution system is configured around 6.9 kV buses Nos. 1, 2, 3, 4, 5, and 6. All offsite power to the safeguards buses enters the plant via 6.9 kV buses Nos. 5 and 6. 6.9 kV buses Nos. 5 and 6 are normally supplied by the 138 kV offsite circuit but may be supplied by the 13.8 kV offsite circuit. When the plant is operating, 6.9 kV buses 1, 2, 3, and 4 (which supply power to the four reactor coolant pumps) typically receive power from the main generator via the unit auxiliary transformer (UAT). However, when the main generator or UAT is not capable of supporting this arrangement, 6.9 kV buses 1 and 2 receive offsite power via 6.9 kV bus 5 and 6.9 kV buses 3 and 4 receive offsite power via 6.9 kV bus 6. Following a unit trip, 6.9 kV buses 1, 2, 3, and 4 will auto transfer (dead fast transfer) to 6.9 kV buses 5 and 6 in order to receive offsite power.

The 6.9 kV buses Nos. 2, 3, 5 and 6 supply power to the 480 V safeguards power buses using 6.9 kV/480 V station service transformers (SSTs) as follows:

a. 6.9 kV bus 5 supplies 480 V bus 5A via SST 5;
b. 6.9 kV bus 6 supplies 480 V bus 6A via SST 6;
c. 6.9 kV bus 2 supplies 480 V bus 2A via SST 2; and,
d. 6.9 kV bus 3 supplies 480 V bus 3A via SST 3.

The onsite AC Power Distribution System begins with the four 480 V safeguards power buses 5A, 6A, 2A and 3A. The four 480 V safeguards power buses can be supplied by either of the two offsite circuits or the emergency diesel generators. The onsite Power Distribution System is divided into the following:

BASES

BACKGROUND (continued)

a. Three safeguards power trains (trains) consisting of the 480 volt safeguards bus(es) and associated AC electrical power distribution subsystems;
b. Four 125 volt DC bus subsystems; and
c. Four 118 volt vital AC instrument subsystems.

The three safeguards power trains are designed so that any two trains are capable of meeting minimum requirements for accident mitigation and/or safe shutdown. The three safeguards power trains are as follows:

a. train 5A (480 volt bus 5A and associated DG 21);
b. train 6A (480 volt bus 6A and associated DG 23); and
c. train 2A/3A (480 volt buses 2A and 3A and associated DG 22).

OFFSITE SOURCES

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite 480 V ESF bus(es). A detailed description of the offsite power network and the circuits to the 480 V safeguards buses is found in the UFSAR, Chapter 8 (Ref. 2).

Offsite power is supplied from the offsite transmission network to the plant by two electrically and physically separated circuits (a 138 kV circuit and a 13.8 kV circuit). All offsite power enters the plant via 6.9 kV buses Nos. 5 and 6 which are normally connected to the 138 kV offsite circuit but have the ability to be connected to the 13.8 kV offsite circuit. The 138 kV offsite circuit satisfies the requirement in GDC 17 that at least one of the two required circuits can, within a few seconds, provide power to safety-related equipment following a loss-of-coolant accident. The 13.8 kV offsite circuit is considered a delayed access circuit because operator action is normally required to supply offsite power to the plant using the 13.8 kV offsite source.

Both the 138 kV offsite circuit and the 13.8 kV offsite circuit have a preferred and a backup feeder that connects the circuit to the Buchanan substation. For both the 138 kV and 13.8 kV offsite circuits, the preferred IP2 feeder is the backup IP3 feeder and the backup IP2 feeder is the preferred IP3 feeder.

For the 138 kV offsite circuit, IP2 and IP3 each have a dedicated Station Auxiliary Transformer (SAT) that can be supplied by either the preferred or the backup 138 kV feeder. The 138 kV offsite circuit, including the SAT used exclusively for IP2, is designed to supply all IP2 loads, including 4 operating RCPs and ESF loads, when using either the preferred (95332) or

BASES

BACKGROUND (continued)

backup (95331) feeder. There are no restrictions when IP2 and IP3 are both using the same 138 kV feeder concurrently.

For the 13.8 kV offsite circuit, there is a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W92 and a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W93. Feeder 13W92 and its associated auto-transformer is the preferred feeder for the IP2 13.8 kV circuit and the backup feeder for the IP3 13.8 kV circuit. Feeder 13W93 and its associated auto-transformer is the backup feeder for the IP2 13.8 kV circuit and the preferred feeder for the IP3 13.8 kV circuit.

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Distribution System. Within 1 minute after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via individual load timers associated with each large load.

ONSITE SOURCES

The onsite standby power source consists of three 480 V diesel generators (DGs) with a separate DG dedicated to each of the safeguards power trains. Safeguards power train 5A (480 V bus 5A) is supported by DG 21; safeguards power train 6A (480 V bus 6A) is supported by DG 23; and, safeguards power train 2A/3A (480 V buses 2A and 3A) is supported by DG 22. A DG starts automatically on a safety injection (SI) signal or on an ESF bus degraded voltage or undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus 5A or 6A undervoltage or degraded voltage, coincident with an SI signal or unit trip. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by individual load timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

BASES

BACKGROUND (continued)

In the event of a loss of the 138 kV offsite circuit, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

~~Ratings for DGs 21, 22 and 23 are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). Each diesel generator consists of an Alco Model 16-251-E engine coupled to a Westinghouse 900 rpm, 3-phase, 60-cycle, 480 V generator. Each diesel generator has a capability of 1750 kW (continuous), 2300 kW for 1/2 hour in any 24 hour period, and 2100 kW for 2 hours in any 24 hour period. There is a sequential limitation whereby it is unacceptable to operate DGs for two hours at 2100 kW followed by operating at 2300 kW for a half hour. Any other combination of the above ratings is acceptable. The ESF loads that are powered from the 480 V ESF buses are listed in Reference 2.~~

INSERT A

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least 2 of the 3 safeguards power trains energized from either onsite or offsite AC sources during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

BASES

LCO

Two qualified circuits between the offsite transmission network and the onsite Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit. In addition, required individual load timers for ESF loads must be OPERABLE unless associated with equipment that has automatic initiation capability disabled.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

There are two qualified circuits from the transmission network at the Buchanan substation to the onsite electric distribution system. Each of these circuits must be supported by a circuit from the offsite network into the Buchanan substation that is physically independent from the other circuit to the extent practical. The circuits into the Buchanan substation that satisfy these requirements are 96951, 96952 and 95891. The 138 kV connection to Buchanan substation from the Westchester Refuse Energy Services Company (RESCO) plant may not be used to satisfy requirements for a circuit from the offsite network into the Buchanan substation.

The 138 kV offsite circuit consists of the following:

a. Either 138 kV feeder 95332 (the preferred feeder for IP2 and the backup feeder for IP3) or 138 kV feeder 95331 (the backup feeder for IP2 and the preferred feeder for IP3);

b. The 138 kV/6.9 kV station auxiliary transformer including the automatic tap changer, circuit breakers ST5 and ST6 which supply 6.9 kV buses 5 and 6, and

c. The following components which are common to both the 138 kV and 13.8 kV offsite circuits:

BASES

LCO (continued)

i. The supply to 480 V bus 5A consisting of 6.9 kV bus 5, circuit breaker SS5, station service transformer 5, and circuit breaker 52/5A;

ii. The supply to 480 V bus 6A consisting of 6.9 kV bus 6, circuit breaker SS6, station service transformer 6, and circuit breaker 6A;

iii. The supply to 480 V bus 2A consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (including fast transfer function), 6.9 kV bus 2, circuit breaker SS2, station service transformer 2, and circuit breaker 52/2A; and

iv. The supply to 480 V bus 3A consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (including fast transfer function), 6.9 kV bus 3, circuit breaker SS3, station service transformer 3, and circuit breaker 52/3A.

LCO 3.8.1 is modified by a Note that requires that the automatic transfer function for 6.9 kV buses 1, 2, 3, and 4 from the UAT (main generator) to 6.9 kV buses 5 and 6 (the 138 offsite circuit) to be OPERABLE whenever the 138 kV offsite circuit is being used to supply 6.9 kV bus 5 and 6 and the Unit Auxiliary Transformer (main generator) is supplying 6.9 kV bus 1, 2, 3 or 4. This is necessary to ensure that safeguards power train 2A/3A (480 volt buses 2A and 3A) will be transferred automatically from the UAT (main generator) to 6.9 kV buses 5 and 6 (the 138 offsite circuit) following a plant trip.

The 13.8 kV offsite circuit consists of the following:

a. Either 13.8 kV feeder 13W92 and its associated 13.8/6.9 kV autotransformer (the preferred for IP2 and the backup feeder for IP3) or 13.8 kV feeder 13W93 and its associated 13.8/6.9 kV autotransformer (the backup for IP2 and the preferred feeder for IP3),

b. Circuit breakers GT25 and GT26, which supply 6.9 kV buses 5 and 6, and

c. The following components which are common to both the 138 kV and 13.8 kV offsite circuits:

BASES

LCO (continued)

i. The supply to 480 V bus 5A consisting of 6.9 kV bus 5, circuit breaker SS5, station service transformer 5, and circuit breaker 52/5A;

ii. The supply to 480 V bus 6A consisting of 6.9 kV bus 6, circuit breaker SS6, station service transformer 6, and circuit breaker 6A;

iii. The supply to 480 V bus 2A consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (not including fast transfer function), 6.9 kV bus 2, circuit breaker SS2, station service transformer 2, and circuit breaker 52/2A; and

iv. The supply to 480 V bus 3A consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (not including the fast transfer function), 6.9 kV bus 3, circuit breaker SS3, station service transformer 3, and circuit breaker 52/3A.

If the 13.8 kV offsite circuit is being used to supply 6.9 kV bus 5 and/or 6 and the Unit Auxiliary Transformer (main generator) is supplying 6.9 kV bus 1, 2, 3 or 4, the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 from the UAT (main generator) to 6.9 kV buses 5 and 6 (the 13.8 offsite circuit) must be disabled. This is necessary because neither the preferred or the backup 13.8 kV/6.9 kV auto-transformer is capable of supplying all 4 operating RCPs. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the 13.8 kV offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded by these manual actions.

If IP3 and IP2 are both using a single 13.8 kV feeder (13W92 or 13W93), administrative controls are used to ensure that the 13.8 kV/6.9 kV auto-transformer load restrictions will not be exceeded.

Operability of the offsite power sources requires the ability to provide the required capacity during design basis conditions. The minimum offsite voltage necessary to provide the required capacity was determined, using system load flow studies with conservative assumptions (Reference 11), to be greater than or equal to 136 kV and 13.4 kV for the 138 kV and 13.8 kV circuits, respectively. Upon notification by Con Ed that these limits are not met, the LCO is considered not met at the time of the initial alarm. When the grid monitoring system is operating the minimum acceptable voltage varies with grid conditions and Con Ed will provide notification.

BASES

LCO (continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in safeguards power train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus and not violate separation criteria. An offsite circuit that is not connected to an ESF bus is required to have OPERABLE automatic or manual transfer capability to the ESF buses to support OPERABILITY of that circuit.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients and

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG or the 138 kV offsite circuit. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG. This also applies to the 138 kV offsite circuit which is the only immediate access offsite circuit. Therefore, the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in these circumstances.

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. For activities that will require entry into the associated Condition, performance of SR 3.8.1.1 for the offsite circuit(s) could be completed up to 8 hours prior to entry into the Condition. Performance of this SR before entry into the Condition can be credited to establish the accelerated Frequency and therefore is equivalent to performing the SR within 1 hour after entry into the Condition. The LCO Bases describes the components and features which comprise the offsite circuits. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which applies only if the 13.8 kV offsite power circuit is being used to feed 6.9 kV buses 5 or 6 and the UAT is supplying 6.9 kV bus 1, 2, 3 or 4, prevents the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 from the UAT to the 13.8 kV offsite power circuit after a unit trip. Transfer of buses 1, 2, 3, and 4 from the UAT to the 13.8 kV offsite power circuit could result in overloading the 13.8 kV/6.9 kV autotransformer. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the 13.8 kV offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded. Automatic transfer of buses 1, 2, 3, and 4 can be disabled by placing 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the "pull-out" position. These breaker control switches should be "tagged" in the pull-out position if this condition is expected to last more than one full shift.

Although the auto-transfer feature is normally disabled prior to placing the 13.8 kV offsite power circuit in service, a Completion Time of 1 hour ensures that the 13.8 kV circuit meets requirements for OPERABILITY promptly

BASES

ACTIONS (continued)

when the alternate offsite circuit is configured to support the response of ESF functions.

BASES

ACTIONS (continued)

A.3

Required Action A.3, which only applies if the train will not be automatically powered from an offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of redundant required features. When one or more offsite sources are inoperable, a train may not be automatically powered from an offsite source if: 1) the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to 6.9 kV bus 5 and 6 is disabled; or 2) the immediate access circuit (138 kV) is inoperable and the delayed access circuit (13.8 kV) is not aligned to replace the inoperable circuit.

Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train. Therefore, if a required safety feature is supported by an inoperable offsite circuit, then the failure of the DG associated with that required safety feature will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train. However, if a required safety feature is supported by an inoperable offsite circuit and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then the failure of the DG associated with that required safety feature will result in the loss of a safety function. Required Action A.3 ensures that appropriate compensatory measures are taken for a Condition where the loss of a DG could result in the loss of a safety function when an offsite circuit is not OPERABLE.

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is by itself capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action A.3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

BASES

ACTIONS (continued)

a. The train will not have offsite power automatically supplying its loads following a trip of the main turbine generator or following the loss of the immediate access offsite circuit, and

b. A required feature powered from a different safeguards power train is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering that offsite power is not automatically available to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the two remaining safeguards power trains of the onsite Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. For activities that will require entry into the associated Condition, performance of SR 3.8.1.1 for the offsite circuit(s) could be completed up to 8 hours prior to entry into the Condition. Performance of this SR before entry into the Condition can be credited to establish the accelerated Frequency and therefore is equivalent to performing the SR within 1 hour after entry into the Condition. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if an offsite circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of redundant required features. Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train. Therefore, if a required safety feature is supported by an inoperable DG, then the failure of the offsite circuit will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train (and DG). However, if a required safety feature is supported by an inoperable DG and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then a loss of offsite power will result in the loss of a safety function. Required Action B.2 ensures that appropriate compensatory measures are taken for a Condition where the loss of offsite power could result in the loss of a safety function when a DG is not OPERABLE.

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, not required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is by itself capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

BASES

ACTIONS (continued)

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists and

b. A required feature powered from a different safeguards power train is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with either OPERABLE DG, results in starting the Completion Time for the Required Action. A Completion Time of four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DGs, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common

BASES

ACTIONS (continued)

cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 10), 24 hours is reasonable to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Distribution System. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.3). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that three complete safeguards power trains are OPERABLE. When a redundant required feature is not OPERABLE, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are not included as discussed in the Bases for Required Action A.3.

BASES

ACTIONS (continued)

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

BASES

ACTIONS (continued)

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Similarly, when the UAT is being used to supply 6.9 kV bus 1, 2, 3 or 4 and the 13.8 kV offsite circuit is being used to supply 6.9 kV buses 5 and 6, the autotransfer function is disabled. Therefore, 480 V safeguards buses 2A and 3A (safeguards train 2A/3A) will not be automatically re-energized with offsite power following a plant trip until connected to the offsite circuit by operator action. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC offsite or DG source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train is or would be de-energized. LCO 3.8.9 provides the appropriate restrictions for a train that is or would be de-energized.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

E.1

With two or more DGs inoperable, the remaining standby AC sources are not adequate to satisfy accident analysis assumptions. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1 and H.1

Conditions G and H correspond to a level of degradation in which all redundancy in the AC electrical power supplies has been lost or a loss of safety function has already occurred. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

BASES

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 7). Periodic component tests are supplemented by functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Regulatory Guide 1.137 (Ref. 8), as addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 428 V is the value determined to be acceptable in the analysis of the degraded grid condition. This value allows for voltage drop to the terminals of 480 V motors. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 500 V is equal to the maximum operating voltage specified for 480 V circuit breakers. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

<u>SR 3.8.1.1</u>

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The lineup check verifies breaker alignment between 480 V buses 5A and 6A and the point where the 138 kV and 13.8 kV feeders being used to satisfy this LCO lose their identity in the offsite network. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because 6.9 kV bus status and 13.8 kV circuit status is displayed in the control room. For breakers that do not have position indication in the control room, this SR is satisfied by telephone communication with Consolidated Edison personnel capable of confirming the status of the offsite circuits. This SR includes confirmation of the requirement for two independent circuits (i.e., 96951, 96952 or 95891) into the Buchanan substation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR is modified by a Note to indicate that all DG starts for the Surveillance may be preceded by an engine prelube period.

For the purpose of SR 3.8.1.2 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that, at a 31 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 14 (Ref. 5).

In addition to the SR requirements, the time for the DG to reach steady state operation is periodically monitored and the trend evaluated to identify degradation of governor and voltage regulator performance.

The 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing. DG 21 and DG 23 have redundant air start motors and both air start motors are actuated by both channels of the start logic. D~~G~~G 21 and DG 23 are operable when either air start motor is operable; however, this SR will not demonstrate that both air start motors are independently capable of starting the DG. If an air start motor is not capable of performing its intended function, a DG is inoperable until a timed start is conducted using the remaining air start motor. Alternately, this SR may be performed using one air start motor (i.e. redundant air start motor isolated) on a staggered basis to ensure that the DG will start with either air start motor. The foregoing does not apply to DG 22 as the starting logic is not actuated by both channels. With either air start motor inoperable DG 22 is also inoperable.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start, without an intervening shutdown, must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and ensures adequate fuel oil for approximately 53 minutes of DG operation at full load.

A 24 hour Frequency is needed because the day tank level alarm is not set to alarm when the day tank level falls just below the minimum required level. Instead, the day tank level alarm is set to indicate a lower level indicative of a failure of the transfer pump after allowing sufficient time for manually

BASES

SURVEILLANCE REQUIREMENTS (continued)

restoring power to the transfer pumps which are stripped following a Safety Injection signal or undervoltage signal on buses 5A or 6A. The 24 hour Frequency is acceptable because operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 8). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The IP2 design includes the following backup feature. If a fuel oil transfer pump fails to refill the day tank, one of the fuel oil transfer pumps associated with a different DG will receive an automatic starting signal and will fill the day tank for the affected DG via the common makeup line to all three diesel-generator fuel-oil day tanks. This backup feature is not required for DG OPERABILITY; however, the feature is tested because its existence is part of the justification for the 92 day SR Frequency. Therefore, the need for accelerated testing of the transfer function should be evaluated when this backup feature is out of service.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency for this SR is 92 days. The 92 day Frequency corresponds to the testing requirements for pumps as contained in the ASME Code, Section XI.

SR 3.8.1.7

Transfer of each offsite power supply from the 138 kV offsite circuit to the 13.8 kV offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. 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, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced.

SR 3.8.1.8

Verification that 6.9 kV buses 2 and 3 will auto transfer (dead fast transfer) from the Unit Auxiliary Transformer (the main generator) to 6.9 kV buses 5 and 6 (the offsite circuit) following a loss of voltage on 6.9 kV buses 2 and 3 is needed to confirm the OPERABILITY of a function assumed to operate to provide offsite power to safeguards power train 2A/3A following a trip of the main generator. (Note that when the main generator trips on over-frequency, the transfer is blocked by an over-frequency transfer interrupt circuit provided for bus protection of out of phase transfer.)

An actual demonstration of this feature requires the tripping the main generator while the reactor is at power with the main generator supplying 6.9 kV buses 2 and 3. Credit may be taken for planned plant trips or for unplanned events that satisfy this SR. Other than

BASES

SURVEILLANCE REQUIREMENTS (continued)

planned plant trips or unplanned events, Note 1 specifies that this SR is not normally performed in MODE 1 or 2 because performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced.

In lieu of actually initiating a circuit transfer, this SR may be satisfied by testing that adequately shows the capability of the transfer. This transfer testing may include any sequence of sequential, overlapping, or total steps so that the entire transfer sequence is verified.

The 24 month Frequency is based on engineering judgement taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length.

Note 2 specifies that this SR is required to be met only when the 138 kV offsite circuit is supplying 6.9 kV bus 5 and 6 and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4. This is acceptable because the feature being tested does not perform a safety function if the 138 kV offsite circuit is already supplying 6.9 kV buses 2 and 3. Likewise, if the 13.8 kV circuit is supplying 6.9 kV buses 5 or 6, then the feature being tested by this SR is required to be disabled by Required Action A.2.

SR 3.8.1.9

This Surveillance demonstrates that DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed, low lube oil pressure, high crankcase pressure, and start failure relay (engine overcrank)) trip the DG to avert substantial damage to the DG unit. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

SR 3.8.1.10

~~IEEE 387-1995 (Ref. 9) requires demonstration~~ ***This surveillance demonstrates*** once per 24 months that the DGs can start and run continuously at full load capability for an interval of not less than 8 hours, ***where for ≥ 105 minutes and ≤ 2 hours loaded at ≥ 2050 kW and ≤ 2100kW, the 2 hour rating, followed by, ≥ 10 minutes and ≤ 15 minutes loaded ≥ 2270 kW and ≤ 2300 kW, the ½ hour rating, and the remainder of the time ≥ 1700 kW and ≤ 1750 kW, the continuous rating.*** ~~≥ 2 hours of which is at a load equivalent to 105% to 110% of the continuous duty rating (1837 kW to 1925 kW) and the remainder of the time at a load equivalent to 90% to 100% of the continuous duty rating of the DG (1750 kW).~~ The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR. ***The load interval is consistent with the recommendations of IEEE 387-1995 (Ref. 9).***

BASES

SURVEILLANCE REQUIREMENTS (continued)

This SR ~~does not~~ require***s*** that the DG ~~is~~ ***be*** operated at the peak load expected during an accident~~. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain~~ ***to demonstrate*** DG OPERABILITY.

The 24 month Frequency is consistent with the recommendations of Reference 9, takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment.

Note 3 ensures that the DG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed at a power factor of ≤ 0.8~~5~~***8 for DG 21 and 22 and ≤ 0.87 for DG 22***. This power factor is representative of the actual inductive loading a DG would see under design basis accident conditions. Under certain conditions, however, Note 3 allows the surveillance to be conducted a~~s~~***t*** an***other*** power factor~~ other than ≤ 0.85~~. *These conditions occur when grid voltage is high, and the additional* field excitation needed to get the power factor to~~ ≤ 0.85~~ ***desired values***

BASES

SURVEILLANCE REQUIREMENTS (continued)

results in voltages on the emergency busses that are too high. Under these conditions, the power factor should be maintained as close as practicable to ~~0.85~~ ***the desired values*** while still maintaining acceptable voltage limits on the emergency busses. In other circumstances, the grid voltage may be such that the DG excitation levels needed to obtain a power factor ~~of 0.85~~ ***as desired*** may not cause unacceptable voltages on the emergency busses, but the excitation levels are in excess of those recommended for the DG. In such cases, the power factor shall be maintained close as practicable to ~~0.85~~ ***the desired values*** without exceeding the DG excitation limits.

SR 3.8.1.11

Under accident conditions loads are sequentially connected to the bus by the individual load timers to prevent overloading of the DGs or offsite circuits due to high motor starting currents. The design load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage or the offsite circuit to restore voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 24 months is based on engineering judgment, taking into consideration operating experience that has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note that specifies that load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. This note is needed because these time delay relays affect the OPERABILITY of both the AC sources (offsite power and DG) and the specific load that the relay starts. If a timer fails to start a required load or if a timer starts the load later than assumed in the analysis, then the required load is not OPERABLE. If a timer starts the load outside the design interval (early or late), then the DG and offsite source are not OPERABLE because overlap of equipment starts may cause an offsite source to exceed limits for voltage or current or a DG to exceed limits for voltage, current or frequency. Therefore, when an individual load sequence timer is not OPERABLE, it is conservative to disable the automatic initiation capability of that component (and declare the specific component inoperable) rather than declare the associated DG and offsite circuit inoperable because of the following: the potential for adverse impact on the DG by simultaneous start of ESF equipment is eliminated; all other loads powered from the safeguards power train are available to respond to the event; and, the load

BASES

SURVEILLANCE REQUIREMENTS (continued)

with the inoperable timer remains available for a manual start after the one minute completion of the normal starting sequence.

If a load sequence timer is inoperable and the automatic initiation capability of that component has not been disabled, Condition D applies because both the associated DG and the 138 kV offsite circuit are inoperable until automatic initiation capability of the associated component has been disabled.

SR 3.8.1.12

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. This SR verifies all actions encountered from an ESF signal concurrent with the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or residual heat removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation.

In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

BASES

SURVEILLANCE REQUIREMENTS *(continued)*

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 24 months.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs.

The reason for Note 2 is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g. post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment.

The reason for Note 3 is to allow the SR to be conducted with only one safeguards train at a time or with two or three safeguards trains concurrently. Allowing the LOOP/LOCA test to be conducted using one safeguards power train and one DG at a time is acceptable because the safeguards power trains are designed to respond to this event independently. Therefore, an individual test for each safeguards power train will provide an adequate verification of plant response to this event.

Simultaneous testing of all three safeguards power trains is acceptable as long as the following plant conditions are established:

a. All three DGs are available;

BASES

SURVEILLANCE REQUIREMENTS (continued)

b. Redundant decay heat removal capability is available, preferably including passive decay heat removal capability;

c. No offsite power circuits are inoperable; and

d. No activities that are precursors to events requiring AC power for mitigation (e.g., fuel handling accident or inadvertent RCS draindown) are conducted during performance of this test.

SR 3.8.1.13

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is to allow SR 3.8.1.12 to satisfy the requirements of this SR if SR 3.8.1.12 is performed with more than one safeguards power train concurrently.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 3, July 1993.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 14.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. 10 CFR 50, Appendix A, GDC 18.
8. Regulatory Guide 1.137.

BASES

REFERENCES (continued)

9. IEEE Standard 387-1995, IEEE Standard Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations.

10. Generic Letter 84-15, July 2, 1984.

11. Calculation SGX-00073-01, dated February 6, 2004.

12. Indian Point Unit 2 License Amendment 153, dated May 9, 1991.

INSERT A for page B 3.8.1-4:

Each diesel generator consists of an Alco Model 16-251-E engine coupled to a Westinghouse 900 rpm, 3-phase, 60-cycle, 480 V generator. The ESF loads that are powered from the 480 V ESF buses are listed in Reference 2. The DG ratings (Reference 12) are as follows:

Continuous	Normal steady-state electrical power output capability that can be maintained 24 hours/day, with no time constraint.
2-hour	An overload electrical power output capability that can be maintained for up to 2 hours in any 24-hour period.
½-hour	An overload electrical power output capability that can be maintained for up to 30 minutes in any 24 hour period.

The electrical output capabilities applicable to these three ratings are as follows:

RATING	DG LOAD	TIME CONSTRAINT
Continuous	$\leq$ 1750 kW	None
2-hour	$\leq$ 2100 kW	$\leq$ 2 hours in any 24-hour period [Note A]
½-hour	$\leq$ 2300 kW	$\leq$ 30 minutes in any 24-hour period [Note A]

Note A: Operation at the overload ratings is allowed only for $\leq$ 2300 kW (1/2-hour) followed by $\leq$ 2100 (2-hour), not vice versa.

The loading cycle (½ -hour, 2-hour, continuous) may be repeated in successive 24-hour periods. Operation in excess of 2300 kW, regardless of duration is not analyzed. In such cases, the DG is assumed to be inoperable and the vendor should be consulted.

The above information applies to the DG ratings. SR 3.8.1.10 provides the required loading values, times, and sequences to assure that load testing bounds the actual DG load profiles.

Enclosure 1 TO NL-08-139

Emergency Operating Procedures (EOPs) Referenced in Diesel Load Studies in Response to Question 8 of **Request for Additional Information**

ENTERGY NUCLEAR OPERATIONS, INC
INDIAN POINT NUCLEAR GENERATING UNIT NO. 2
DOCKET No. 50-247

List of Procedures included in Enclosure 1

EOP Number	EOP Title	Revision No.
E-0	Reactor Trip or Safety Injection	38
ES-0.0	Rediagnosis	34
ES-0.1	Reactor Trip Response Natural Circulation	36
ES-0.2	Cooldown Natural Circulation	34
ES-0.3	Cooldown with Steam Void in Vessel (with RVLIS) Natural Circulation	34
ES-0.4	Cooldown with Steam Void in Vessel (without RVLIS)	34
E-1	Loss of Reactor Coolant	36
ES-1.1	SI Termination	36
ES-1.2	Post LOCA Cooldown and Depressurization	36
ES-1.3	Transfer to Cold Leg Recirculation	36
ES-1.4	Transfer to Hot Leg Recirculation	36
E-2	Faulted Steam Generator Isolation	34
E-3	Steam Generator Tube Rupture	36
ES-3.1	Post SGTR Cooldown Using Backfill	34
ES-3.2	Post SGTR Cooldown Using Blowdown	34
ES-3.3	Post SGTR Cooldown Using Steam Dump	34
ECA-0.0	Loss of all AC Power	37
ECA-0.1	Loss of all AC Power Recovery without SI Required	34
ECA-0.2	Loss of all AC Power Recovery with SI Required	34
ECA-1.1	Loss of Emergency Coolant Recirculation	34