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SUBJECT: Submits technical descriptions & plant test results which demonstrate manual control of characteristic selection of automatic speed & voltage control sys for diesel generators acceptable & meets Reg Guide 1.9.

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March 10, 1986
G02-86-201

Docket No. 50-397

Director of Nuclear Reactor Regulation
Attention: Ms. E.G. Adensam, Project Director
BWR Project Directorate No. 3
Divison of BWR Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Ms. Adensam:

Subject: NUCLEAR PLANT NO. 2
STANDBY DIESEL GENERATOR AUTOMATIC
RETURN TO STANDBY MODE

Reference: Letter G02-83-1111, G.C. Sorensen (SS) to A. Schwencer (NRC), Standby Diesel Generator Automatic Return to Standby Mode, dated December 2, 1983

The reference notified the staff that the WNP-2 Diesel Generator (DG) design feature for automatic speed control characteristic switching did not work correctly. Furthermore it committed to either implement a design change for automatic control characteristic selection at the first refueling outage or provide technical justification for not implementing such a change. Additionally, in the interim, a committment to have an operator present to manually switch controls during any DG testing in parallel with the network power source was made. The purpose of this letter is to provide the technical descriptions and plant test results which demonstrate that manual control of the characteristic selection of the automatic speed and voltage control systems for the WNP-2 DG's is acceptable and meets all Regulatory requirements.

Description of Problem

The original design did not allow the transfer of a loaded bus between the onsite power source and the offsite power sources as required by IEEE 308 (Reg. Guide 1.32), IEEE 387 (Reg. Guide 1.9) and IEEE 749, in an orderly and controlled manner. In the original design the speed control system was switched from "isochronous" to "droop" characteristic when both the DG breaker and an offsite power incoming line breaker were closed indicating

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the DG was in parallel with the network. This arrangement meant that the speed matching required for proper synchronizing was done with speed control in "isochronous". As soon as the tie breaker closed, the speed control switched to "droop" resulting in a mismatch between the DG speed control setpoint and the network speed. The automatic speed governor then attempted to reduce speed to the setpoint by reducing the throttle setting. Since the DG was locked in synchronism with the network, the speed (frequency) of the DG could not change. The governor drove the throttle closed, the anti motoring protection tripped the generator and engine, and the DG was shut-down and locked out. The normal procedure for transferring a loaded bus from the on-site power system to the off-site system is to parallel, gradually unload the DG, manually open the DG breaker at a low value of load (200-400 KW), and stop the engine. This process leaves the DG in standby ready to start and energize its bus in response to accident signals. The problem was corrected by restoring the speed control characteristic switch to manual operation so that the operator could switch to "droop" before he did the speed matching required to parallel.

Description of WNP-2 DG Speed and Voltage Control Systems

The WNP-2 DG's are equipped with an electric automatic speed governor system which controls the diesel engine throttles. This system senses generator output frequency (speed), compares the output frequency with the governor setpoint, and then adjusts the throttle positions in a direction so that the output frequency will match the setpoint. On the Division 1 and 2 DG's which have dual engines, this system controls both engine throttles so that both engines will share the load equally. The system has no provisions for manual control of throttle position. The throttles are always under the control of the automatic governor system. The governor control setpoint is manually adjustable. The governor speed-load characteristic can be manually switched from "isochronous" (constant frequency-independent of load) to "droop" (frequency (speed) setpoint is varied with load such that it increases on decreasing load and decreases (or droops) on increasing load). The speed-load droop characteristic is essential to permit stable control of load (i.e., DG throttle position) when the DG is operated in parallel with the network, with the DG throttle under control of the automatic frequency governor.

Once the DG is paralleled to the network, it is locked in synchronism with the network. Its frequency (speed) is fixed at the network frequency. A change in the throttle setting no longer changes DG frequency, it only changes generator load output. If the governor were in "isochronous" any slight mismatch between the DG governor setpoint and the network frequency would drive the throttle either fully open or fully closed because no frequency correction occurs. When the frequency governor has a slope to it's speed-load characteristic, stable control of the engine throttle position (and hence generator load) is provided because the frequency setpoint of the governor changes with load until it matches the network frequency. When the DG is in parallel with the network, the operator controls load by manually raising or lowering the setpoint of the automatic

frequency governor. At no load, the frequency setpoint is the same for both the isochronous and droop governor control characteristics. The slope of the frequency (speed) - load characteristic is about 3% from no load to full load. The governor setpoint is manually set at 60 Hz with the DG running at no load just before it is shut-down and left in standby.

The WNP-2 DG generators are equipped with a shunt-fed static excitation system controlled by an automatic voltage regulator which supplies and controls the field current to the generator. The system does have provision for manual control of field current; however, it is never used. The system is always operated under control of the automatic voltage regulator. Manual control of field current would be used only if the voltage regulator failed at a time when DG output was necessary. The voltage regulator senses generator output terminal voltage, compares it with its voltage setpoint, and then increases or decreases field current until the generator terminal voltage equals the voltage setpoint. The voltage regulator setpoint is manually adjustable. The voltage regulator voltage-load control characteristic can be manually switched from "Unit" (constant voltage-independent of load) to "Parallel" (voltage setpoint is varied with load current flow such that it increases on decreasing load current and decreases ("Droops") on increasing load current flow. The slope of the voltage-load current control characteristic is about 5% voltage setpoint change when the load current varies from 0 to generator rated load.

When the DG is paralleled to the network, the generator terminal voltage is determined primarily by the network voltage. A change in field current no longer changes terminal voltage, it only causes a change in reactive current flow. If the generator voltage regulator were in the "Unit" (constant voltage) control characteristic, any small mismatch between the network voltage and the voltage regulator setpoint would cause the voltage regulator to drive the field current to its maximum or minimum. When the voltage regulator setpoint has a voltage-load current slope (i.e., "parallel" characteristic), stable control of field current is provided because the voltage regulator setpoint changes with current flow until its setpoint matches the network voltage. When the DG is in parallel with the network, the operator controls reactive current flow by manually raising or lowering the setpoint of the voltage regulator. The voltage regulator setpoint in "parallel" operation at no load is the same as the setpoint in "Unit" operation. The voltage regulator setpoint is manually set at 4200 volts with the DG running at no load just before it is shut down and left in standby.

## Analysis and Test Results

Reg. Guide 1.108 requires that the rated-load carrying capability (continuous rating) of the on-site power source DG's be demonstrated for a minimum of one hour during periodic testing. At WNP-2 loading to the DG rating is accomplished by paralleling the DG with the off-site network. In order to provide stable control of reactive load flow, the voltage regulator is switched to "parallel" characteristic prior to synchronizing.

The same switch picks up a relay that puts the governor in "droop". When the DG is then loaded against the network to full load, it means that the governor setpoint in "droop" has been adjusted to match the network frequency at full load and the voltage regulator setpoint in "parallel" has been adjusted to match the network voltage at full load. If a LOCA occurs while a DG is in parallel with the network, the DG breaker is tripped to terminate the test. If a loss of off-site power occurred, the DG would energize the ESF bus and pick up the load automatically. Assuming no manual correction of the governor or voltage regulator control characteristic or setpoint, the governor and voltage regulator would control speed and voltage at a setpoint that will rise from the network values along the slope of their control characteristic in proportion to the difference between the applied load and the rated load.

In Special Test Procedure SLT-S47.1-13, (see Attachment 1, steps 5.3 and 5.4), the frequency and voltage regulation of the Division 2 DG was measured. The frequency regulation was found to be 2.6% from no load to rated load and the voltage regulation was found to be 4.5% from no load to rated load. The automatically applied ESF loads range from 74 to 96% of the DG continuous rating depending on the division and the contingency. With the control characteristics set in "parallel", the largest deviation from the network frequency and voltage will occur at the smaller load. At 74% load the governor setpoint would be 26% of 2.6% above the network frequency (i.e. 100.7% of the network frequency). At 74% load the voltage regulator setpoint will be 26% of 4.5% above the network voltage (i.e. 101.2% of the network voltage).

In Special Test SLT-S47.1-13 (Attachment 1, Step 5.6), the frequency and voltage were measured at a load of 3200 KW (72%) with the governor and voltage control characteristics set for "parallel"(or "droop") and no setpoint adjustments following rated loading against the network. The frequency was 101% of nominal and the voltage was 101.6% of the network voltage which was 103.8% of nominal because the network voltage was 102.2% of nominal (4160V) at the time of the test.

The transient response of the DG to step changes in load is the same whether the control characteristic is in "parallel" ("droop") or "Unit" ("Isochronous"). The transient performance was measured in Special Test SLT-S47.1-13 (see Attachment 1, Step 5.6) for starting the largest automatically started motor (SW-P-1B, 1750 HP). On the motor start, the voltage dipped to 86.5% of nominal and recovered to 105.2% nominal in 0.3 seconds. The frequency dipped to 101% of nominal and recovered to 101.6% of nominal in 1.4 seconds.

The preceding calculated and measured values for voltage and frequency for the WNP-2 DG's in unit operation following interuption of the required rated load testing are well within the requirements set by Reg. Guide 1.9 and, therefore are acceptable. If the DG's are required to carry load before the control characteristics and setpoints of the governor and voltage regulator can be manually connected, the resulting voltage and

frequency will be closer to nominal values in "parallel" ("droop") characteristic than they would be if the characteristic were automatically switched to "Unit" ("isochronous"). The transient response of the DG to step load changes is not affected since the DG is always under control of the governor and the voltage regulator.

Effects on Reliability

There is no technical impediment to designing and implementing a workable scheme to switch the DG voltage regulator and governor control characteristic from "parallel" ("droop") to "Unit" ("isochronous") in the event of a LOCA while the DG is paralleled with the network for load testing (even though the original design failed to work in an acceptable manner). Such a design would have to include correcting the setpoints as well as switching the control characteristics to provide performance identical to the performance in normal standby. The setpoints for both the voltage regulator and governor are adjusted by means of motor operated potentiometers.

Because the mission reliability of our on-site power source DG's is so important to plant safety for Design Basis Events, any modification must be evaluated for its reliability consequences. Implementing this modification will require adding components (circuits, relays, and switches) to either the reactor protection system output circuits or to the DG activation circuits in order to determine that a LOCA has occurred. Any such added components will have failure modes which will reduce the qualitative reliability of the existing systems. In addition, adding circuits to automatically adjust the motor operated potentiometers to correct the setpoints at the time of a LOCA will convert what is a passive device in the present design to an active device. As an active device, it will have additional failure modes which could disable the DG's and hence degrade the qualitative reliability of the DG system.

The function provided by the modification is only needed when the DG is paralleled with the network for the rated load testing required by Reg. Guide 1.108 which requires such testing a minimum of one hour every 31 days and 24 hours every 18 months. Hence, the required time in this test configuration is approximately 41 hours per 18 months or 0.3% of the time. The added failure modes due to the modification will be present 100% of the time.

From the standpoint of the mission reliability of the on-site power system, we can not defend a modification which will degrade the qualitative reliability of the DG's all the time, in order to improve already adequate DG performance in an operating configuration that will exist only 0.3% of the time.

Conclusions

The primary mission of the on-site power system DG's is to start and supply the electrical energy to the ESF loads for a LOCA or safe shut-down in the event of loss of off-site power. The present design of the WNP-2 DG

voltage regulators and governors will automatically provide acceptable DG voltage and frequency for unit operation even if their control characteristic switches are set for "parallel" ("droop") characteristics. A modification to automatically switch these control characteristics to "Unit" ("isochronous") will degrade the qualitative reliability of the DG control system with no offsetting benefits. Therefore, implementing such a modification is not justified.

GC Sorensen

G.C. Sorensen, Manager
Regulatory Programs

DTT:cj

cc: JO Bradfute - NRC
JB Martin - NRC RV
E Revell - BPA
NS Reynolds - BLCP&R
NRC Site Inspector

## ATTACHMENT 1

Special Test Procedure SLT-S47.1-13, "Test of Diesel Generation Excitation and Speed Control Systems" Performed 12/15/83

The following data was read from the original test recording chart.

Step 5.3 - DG at rated load in parallel with network.
Load = 4450 KW, 1200 KVAR
Voltage = 4250 Volts
Frequency = 60.0 Hz

Step 5.4 - DG Breaker tripped, no change in voltage regulator or governor setpoint or control characteristic.
Load = 0 KW, 0 KVAR
Voltage = 4450 Volts
Frequency = 61.6 Hz

Therefore:

Frequency (speed) Regulation in "Droop"

$$= \frac{61.6-60.0}{61.6} = 2.6\%$$

Voltage Regulation in "Parallel"

$$= \frac{4450-4250}{4450} = 4.5\%$$

Step 5.5 - Trip network source breaker, DG energizes bus and picks up residule load.
Final Bus load = 400 KW, 300 KVAR
Reactive Inrush = 2500 KVAR momentary
Voltage Dip = 3800 Volts = 91.3% of Nominal (4160V)
Final Voltage = 4400 Volts = 105.7% of Nominal (4160V)
Time to recover to 90% Of Final Voltage = 0.2 seconds
Frequency dip = 61.2 Hz = 102% of Nominal (60 Hz)
Final Frequency = 61.4 Hz = 102.3% of Nominal (60 Hz)
Time to recover to 100% of Final Frequency = 1.0 seconds

Step 5.6(a) - Start largest automatically started ESF motor - Standby Service Water Pump, 1750 HP
Final Bus load = 1800 KW, 1000 KVAR
Voltage Dip = 3600 Volts = 86.5% of Nominal (4160V)
Final Voltage = 4380 Volts = 105.2% of Nominal (4160V)
Time to recover to Final Voltage = 0.3 seconds
Frequency dip = 60.6 Hz = 101% of Nominal (60 Hz)
Final Frequency = 61.0 Hz = 101.6% of Nominal (60 Hz)
Time to recover to Final Frequency = 1.4 seconds

Step 5.6(b) - Load bus to approximately LOCA load.
Total Load = 3200 KW and 1600 KVAR
Final Frequency = 60.6 Hz = 101% of Nominal (60 Hz)
Final Voltage = 4320 Volts = 103.8% of Nominal (4160V)
= 101.6% of Network Voltage (4250V)

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= 101.6% of Network Voltage (4250V)