DRAFT SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

WCAP-17308-NP, REVISION 0,

"TREATMENT OF DIESEL GENERATOR (DG) TECHNICAL SPECIFICATION FREQUENCY AND VOLTAGE TOLERANCES"

PRESSURIZED WATER REACTOR OWNERS GROUP

PROJECT NO. 694

1.0 INTRODUCTION AND BACKGROUND

The purpose of the diesel generators (DGs) at commercial nuclear power plants is to supply a highly reliable, self-contained source of alternating current (AC) power in the event of a complete loss-of-off-site power (LOOP). The DGs are designed to provide sufficient power for the electrical loads required for a safe shutdown of the plant. This includes the loads required to mitigate the effects of a design-basis accident (DBA) with a complete LOOP plus a single failure in the on-site power system.

The Standard Technical Specifications (STS) have surveillance requirements (SRs) that provide details on operating limits for DGs in order to ensure that they function satisfactorily to mitigate a DBA or transient that may challenge the integrity of fission product barriers. The DG operating limits include steady state allowable voltage and frequency requirements to ensure that accident mitigation equipment can perform as designed.

The plant safety analyses make specific assumptions regarding the emergency core cooling system (ECCS) flow to provide the core cooling function following any event that requires safety injection (SI) to mitigate the event. For the events that assume offsite power is lost, the DGs provide power to the ECCS pumps. Following a LOOP, the DG starts. After it achieves a predetermined voltage and frequency, a permissive signal is generated for DG output breaker closure and connect the DG to an engineered safety feature (ESF) electrical bus. The predetermined voltage and frequency has to be adequate to satisfactorily start and run the equipment that may not have been disconnected after LOOP and load that received permissive signal to start at time zero. Essential loads, including the ECCS pumps, are then sequentially connected to the ESF bus by a load sequencer.

The design basis calculations for ECCS flows typically assume that the steady-state DG frequency is 60 Hertz (Hz) and voltage is 4160 volts (V) AC[1] after the auto load sequencing is completed (i.e., DG reaches a steady state condition after the starting and loading transients). Traditionally, the potential operation of the DG outside the nominal voltage and frequency limits has not been analyzed.

By letters dated May 1 and September 11, 2012 (Agencywide Documents Access and Management System (ADAMS) Accession Nos. ML12125A123 and ML12261A364, respectively), the Pressurized Water Reactor Owners Group (PWROG) submitted Topical

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[1] Some plants have DGs operating at nominal 480V AC or 6900V AC

Enclosure

Report (TR) WCAP-17308-NP, Revision 0, "Treatment of Diesel Generator (DG) Technical Specification Frequency and Voltage Tolerances," for U.S. Nuclear Regulatory Commission (NRC) staff review. The TR provides a method for validating the performance capabilities of accident mitigation equipment operating within the allowable tolerances of DG voltage and frequency. The methodology proposes to treat the tolerance as an uncertainty, similar to an instrument setpoint, and perform an uncertainty calculation which considers the specified tolerance, measurement and test instrument uncertainties, and setting tolerances. The TR proposes to validate the ability of ECCS equipment to perform within the assumptions, considered in the safety analyses, by using the data collected during in-service testing (IST) and equipment testing. Equipment testing included the American Society of Mechanical Engineers (ASME) Operation and Maintenance (OM) Code quarterly or comprehensive pump tests, technical specifications (TS) surveillance tests, or other plant system or component tests.

By letter dated July 10, 2013 (ADAMS Accession No. ML13151A065), the NRC staff issued a request for additional information (RAI) pertaining to electrical aspects of the issues discussed in the WCAP TR. By letter dated August 22, 2013 (ADAMS Accession No. ML15127A186), the PWROG provided responses to the RAIs. By letter dated February 25, 2013 (ADAMS Accession No. ML13019A363), the NRC staff sent RAIs to the PWROG pertaining to the general and mechanical aspects of the TR. By letter dated March 28, 2013 (ADAMS Accession No. ML13093A083), the PWROG provided responses to the RAIs associated with the mechanical aspects of the TR. By letter dated June 30, 2015, the NRC staff sent RAIs pertaining to the use of ASME OM Standard Part 28, "Standard for Performance Testing of Systems in Light-Water Reactor Power Plants." By letter dated August 31, 2015 (ADAMS Accession No. ML15247A070), the PWROG provided responses to the RAIs. The PWROG transmitted additional changes to the TR on February 12, 2015 via letter OG-15-64 (ADAMS Accession No. ML15050A163). The changes are generally editorial in nature, provide corrections to units used in equations, clarify some definitions, and corrected errors in results and responses provided to RAIs. The changes do not impact the proposed methodology or the intent of the original submittal. The PWROG has indicated that following receipt of the final Safety Evaluation (SE) for WCAP-17308-NP, the NRC staff approved version will be issued as WCAP-17308-NP-A, Revision 1, and will incorporate all changes described in the above referenced submittals.

2.0 REGULATORY EVALUATION

Section 50.36, "Technical Specifications," to Title 10 of the *Code of Federal Regulations* Part 50 (10 CFR 50), requires that each applicant for a license authorizing operation of a nuclear production or utilization facility shall include in its application proposed TS in accordance with the requirements of this section.

The regulation at 10 CFR 50.36(c), requires, in part, that the TS will include safety limits, limiting safety system settings, and limiting control settings. Safety limits for nuclear reactors are limits upon important process variables that are found to be necessary to reasonably protect the integrity of certain of the physical barriers that guard against the uncontrolled release of radioactivity. If any safety limit is exceeded, the reactor must be shut down.

Per 10 CFR 50.36(c)(3), TS include SRs relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

General Design Criterion (GDC)-17, “Electric power systems,” of Appendix A, “General Design Criteria for Nuclear Power Plants,” to 10 CFR Part 50, requires, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components (SSCs) that are important to safety.

GDC-18, “Inspection and testing of electric power systems,” states that electric power systems important to safety be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically: (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses, and (2) the operability of the system as a whole and, under conditions as close to design as practical, the full operation sequence that brings the systems into operation, including operation of applicable portions of the protection system, and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system.

GDC-37, “Testing of Emergency Core Cooling System,” requires that the ECCS shall be designed to permit appropriate periodic pressure and functional testing to assure: (1) the structural and leak tight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

<u>The following guidance documents were also considered during the review</u>

The NRC’s guidance for the format and content of licensee TSs can be found in NUREG-1430, “Standard Technical Specifications Babcock and Wilcox Plants;” NUREG-1431, “Standard Technical Specifications Westinghouse Plants;” NUREG-1432, “Standard Technical Specifications Combustion Engineering Plants; ” NUREG-1433, “Standard Technical Specifications General Electric Plants BWR/4;” and NUREG-1434, “Standard Technical Specifications General Electric Plants, BWR/6.”

STS (NUREGs 1430-1434) define “operable/operability” as follows: a system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety functions, and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its function(s) are also capable of performing their related support function(s). In order to be considered operable, SSCs must be capable of performing the safety functions specified by its design, within the required range of design physical conditions, initiation times, and mission times. In addition, TS operability considerations require that SSCs meet all SRs (as specified in the SRs). A SSC that does not meet a SR must be declared inoperable. In order to be considered operable, the SSC must be able to perform its specified safety function for the duration that is credited in the accident analysis for the SSC to perform its specified safety function.

The NRC staff uses NUREG-0800, “Standard Review Plan,” Chapter 16, “Technical Specifications” as guidance to ensure that any proposed changes to TS are in accordance with 10 CFR 50.36. According to this guidance the language in the proposed TS changes must be the same or equivalent to that in the current TS unless there is adequate technical or administrative reasoning supporting the change.

Regulatory Guide (RG) 1.9, Revision 4, “Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants,” provides guidance for design requirements of DGs when sequencing ECCS loads. Section 1.4 of the RG 1.9 pertains to the starting and load-accepting capabilities of the DG and states “The diesel generator should be designed such that the frequency will not decrease, at any time during the loading sequence, to less than 95 percent of nominal and the voltage will not decrease to less than 75 percent of nominal. (A larger decrease in voltage and frequency may be justified for a diesel generator that carries only one large connected load.) Frequency should be restored to within 2 percent of nominal in less than 60 percent of each load-sequence interval for a stepload increase, and less than 80 percent of each load-sequence interval for disconnection of the single largest load. Voltage should be restored to within 10 percent of nominal within 60 percent of each load-sequence interval. The acceptance value of the frequency and voltage should be based on plant-specific analysis (where conservative values of voltage and frequency are measured) to prevent load interruption.”

National Electrical Manufacturers Association Standard (NEMA) MG 1-2014, “Motors and Generators,” provides guidance on standard design requirements for motors and generators used in industrial applications.

3.0 TECHNICAL EVALUATION

Plant safety analyses make specific assumptions regarding the ECCS flow rates required to provide the core cooling function following any event that requires safety injection (SI) to mitigate the consequences of the event. For the events that assume offsite power is lost, the DGs are required to provide power to the ECCS components.

The flow rate of the ECCS pumps is determined by the pump speed, which in turn is a function of the DG frequency and voltage. Historically, the DG frequency and voltage tolerances associated with the governor and voltage regulator were not considered in the development of the flow rates for pumps associated with the ECCS such as the containment spray system and auxiliary feedwater system. The primary effect of reduced frequency and voltage on the ECCS safety functions is to decrease the speed of safety-related motors that are powered by the DG, which affects, for example, pump performance, motor-operated valve (MOV) stroke times, and cooling fan performance. A higher than normal frequency will result in higher speed of rotating equipment and potential increase in the pressure in the ECCS.

The STS contain SRs that place limits on the DG frequency and voltage range. For example, SR 3.8.1 of NUREGs 1430-1434 has a requirement to "Verify each DG starts from standby conditions and achieves steady state voltage > [3740] V and < [4580] V, and frequency > [58.8] Hz and < [61.2] Hz." The typical values (bracketed values) provide generic guidance only and the licensees are expected to consider plant-specific parameters based on design and licensing basis of the plant including equipment capability and accident analyses assumptions.

The allowable range of frequency (between 58.8 Hz and 61.2 Hz) and voltage (between 3740 V and 4580 V) when incorporated directly into plant-specific TS SRs, imply that SSCs can function satisfactorily with a frequency variation of plus or minus (±) 2 percent of the 60 Hz nominal and ±10 percent variation in the 4160 V nominal voltage for the example considered above. (Note, plants also have safety related busses at other voltages). Steady-state DG operation at the extremes of the allowable frequency and voltage limits will have an impact on system design bases, including:

- ECCS performance
- DG loading calculations
- DG fuel oil consumption calculations
- MOV performance
- Heating, ventilation, and air conditioning system performance
- Uninterruptible power supply bypass transfer capability

Licensees validate operability of DGs using the TS related SRs which allow steady-state DG operation within the specified limits. Since the DG can operate at lower or higher than nominal voltage or frequency, the impact of the allowable tolerances in DG frequency and voltage should be evaluated with respect to performance of equipment required to mitigate the consequences of an accient.

In Section 1.1, the TR states that the ±2 percent frequency tolerance and ±10 percent voltage tolerance is only applicable to DG starting and step loading transients, and <u>does not apply to steady-state</u> operation as discussed in RG 1.9, Revision 3. RG Section 1.4 pertains <u>to the starting and load-accepting capabilities of the DG</u> and states that the DG should be designed such that the frequency will not decrease, at any time during the loading sequence, to less than 95 percent of nominal and the voltage will not decrease to less than 75 percent of nominal. (A larger decrease in voltage and frequency may be justified for a DG that carries only one large connected load). Frequency should be restored to within 2 percent of nominal in less than 60 percent of each load-sequence interval for a stepload increase, and less than 80 percent of each load-sequence interval for disconnection of the single largest load. Voltage should be restored to within 10 percent of nominal within 60 percent of each load-sequence interval. The acceptance value of the frequency and voltage should be based on plant-specific analysis (where conservative values of voltage and frequency are measured) to prevent load interruption.

The NRC staff considers the guidance provided in the RG as applicable to the DG voltage and frequency for transient conditions observed during the load sequencing period only. The allowable transient voltage (75 percent) and frequency (95 percent) bands provide assurance that each load that is operating on the DG has adequate voltage and frequency requirements during the sequencing of additional loads and does not stall or trip due to voltage perturbations associated with step loads. The recovery voltage (±10 percent) and frequency (±2 percent) provide assurance that the voltage and frequency oscillations have damped to provide adequate voltage and frequency for the next load that has to be started.

3.1 DG Technical Specification

When the STS was issued as a generic document, it provided guidance parameters ([in square brackets]) for all variables specific to an operating plant including steady state voltage and frequency requirements. The generic allowable parameters in the STS were similar to post transient recovery voltage parameters delineated in RG 1.9. Licensees requesting to adopt the STS through a license amendment are expected to replace the generic values with the plant-specific parameters based on assumptions and criterion used in safety analysis and analytical limits used to demonstrate safe shutdown capability following a DBA.

The TR states that the frequency and voltage criteria are specified in the context of the capability of the DG to recover from a transient such as DG load sequencing. As such, the ±2 percent criterion on frequency and the ±10 percent criterion on voltage should not have been incorporated into the TS as steady-state operating criteria. The NRC staff requested clarification as to why the DG voltage and frequency tolerances should not be included in TS. By letter dated August 22, 2013 (ADAMS Accession No. ML15127A186), the PWROG stated that "A properly functioning governor and voltage regulator will maintain frequency and voltage within tolerances significantly smaller than ±2% Hz and ±10% V."

In response to EEEB-RAI 2 (ADAMS Accession No. ML13151A065) related to frequency variation during load sequencing, the PWROG response stated that the members will include their plant specific tolerances for frequency and voltage, based on the performance capability of the DG governor and voltage regulator and provided marked up examples of applicable TS SRs. The response also stated that the voltage and frequency ranges that are contained in brackets, would be replaced with ranges based on the plant specific performance capability of the governor and voltage regulator.

The NRC staff agrees that a properly functioning governor and exciter should be able to maintain DG frequency and voltage within a narrow band. However, as discussed above, the generic values for variable parameters in the STS should be corrected for plant specific equipment capabilities. Specifically, the TS shall contain revised values for DG voltage and frequency band for steady state operation. The TS for transient recovery voltage and frequency, though not considered within the scope of the TR, should also be evaluated on a plant specific basis.

3.2 Method for Developing Inservice Testing Curves

Section 2 of the TR describes the method of developing IST pump curves that account for uncertainties in DG frequency and voltage. In response to RAI-EPNB-1 (ADAMS Accession No. ML15162A221), the PWROG stated that the IST pump curves mentioned in the TR are not developed using the ASME OM Code. The curves are developed using ASME OM Standard Part 28, "Standard for Performance Testing of Systems in Light-Water Reactor Power Plants." Sections 4.2 and 4.4 of the standard, and other sections that are included in these sections by reference, are used to identify pump performance requirements necessary to meet the plant design and licensing basis and convert these pump performance requirements into test acceptance criteria.

The NRC staff finds that the use of ASME OM Standard Part 28 is a technically acceptable approach to develop of the subject pump curves. Section 4.2 of the standard states that the performance requirements should be identified in a manner consistent with the plant licensing and design bases, including relevant licensing commitments that limit, modify, or clarify system operating requirements. It also defines the source information that may be used to define system performance requirements. Section 4.4 of the standard states that acceptance criteria should be established for the system characteristics, and the acceptance criteria should account for (a) differences between analysis and test considering system configuration and boundary or process fluid conditions and (b) test instrument loop accuracy.

3.2.1 Flow Measurement Uncertainty

Section 2.2.1 of the TR states that a pump flow measurement loop will consist of a primary flow element, a sensor(s), and an instrument loop, and that each licensee has a method for defining the overall uncertainty for the flow measurement loop. The NRC staff finds the system described to be typical for flow measurement loops and that measurement uncertainty for such a loop can be determined. Therefore, the NRC staff finds this approach acceptable.

3.2.2 Pump Developed Head Measurement Uncertainty

Section 2.2.2 of the TR states that the pump developed head is the difference in the static pressure head, velocity head, and elevation head across the pump. It also states that the uncertainty in pump developed head is the combined uncertainty in the measurement of these values.

The NRC staff finds this to be an industry standard approach. The pump developed head is the difference in the static pressure head, velocity head, and elevation across the pump. This is the standard Bernoulli equation. The uncertainty in pump developed head would be the sum of the uncertainties of these three items of the Bernoulli equation.

3.2.3 Uncertainty in Diesel Generator Frequency

Section 2.2.3 of the TR describes the methodology for evaluating the uncertainty in DG frequency. The uncertainty in DG frequency is considered as a random and independent variability and it may be included as an uncertainty in square-root-sum-of-the-squares (SRSS) combination with the test uncertainties. The total uncertainty is calculated by the SRSS method using the uncertainty in governor frequency control and uncertainty in governor frequency setting. Since the DG frequency is typically verified using local (temporary or permanent) or remote meters, the uncertainty in the meter instrument loop should also be accounted for in the uncertainty equation.

RG 1.105, Revision 3, “Setpoints for Safety-Related Instrumentation,” is a method acceptable to the NRC staff for complying with the NRC's regulations for ensuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits. The NRC staff agrees that the governor manufacturer’s specified tolerance should normally be used and licensees may establish plant specific values if the manufacturer data is not available. The TS SRs should validate the capability of the DG to operate within the allowable band.

3.2.4 Uncertainty in Diesel Generator Voltage

Section 2.2.4 of the TR describes the methodology for evaluating the uncertainty in DG voltage. Similar to the method proposed for DG frequency, the TR proposes the SRSS method for evaluating the total uncertainty in voltage regulation. The NRC staff agrees with the proposed methodology. The TS SRs should validate the capability of the DG to operate within the allowable band.

3.2.5 Uncertainty in Pump Developed Head Due to Flow Uncertainty

Section 2.2.5 of the TR evaluates the uncertainty in pump developed head due to flow uncertainty. The TR concludes that the uncertainty in pump developed head due to flow uncertainty is the rate of change of pump developed head with flow multiplied by the uncertainty in flow measurement.

The NRC staff finds this approach to be technically acceptable. The pump developed head varies with the pump flow rate. Therefore, the rate of change of pump developed head with flow, multiplied by the flow measurement uncertainty, equals the uncertainty in pump developed head due to flow uncertainty.

3.2.6 Uncertainty in Pump Speed Due to Diesel Generator Frequency and Voltage Uncertainties

The net effect of voltage and frequency variations on steady-state speed can be closely approximated as the sum of the change due to voltage plus the sum of the change due to frequency. Section 2.2.6 of the TR modifies this relationship to associate the changes in frequency and voltage with frequency and voltage uncertainties. The NRC staff finds this methodology to calculate the uncertainty in pump speed associated with uncertainties in frequency and voltage to be acceptable.

3.2.7 Uncertainty in Pump Head Associated with Uncertainty in Pump Speed

Section 2.2.7 of the TR describes the methodology for determining the uncertainty in pump head due to uncertainty in pump speed. The pump head uncertainty consists of the effect of a change in pump speed on the pump head, and the indirect effect of the change in pump head due to the change in pump flow resulting from the change in pump speed. The NRC staff finds the proposed methodology to be acceptable. The two effects are derived from the pump affinity laws.

3.2.8 Overall Uncertainty in Pump Developed Head

Section 2.2.8 of the TR describes the methodology for determining the overall uncertainty in the pump developed head. This section proposes the SRSS method for determining the overall uncertainty in the pump developed head, which consists of the uncertainty in pump developed head measurement, the uncertainty in pump developed head due to flow uncertainty, and the uncertainty in pump developed head due to uncertainty in pump speed. The NRC staff finds the proposed methodology to be acceptable. Periodic pump testing will validate the capability for the pump to operate within its acceptable band.

3.3 Application of Methodology to Adjust Inservice Test Minimum and Maximum Allowable Pump Curves

Section 2.3 of the TR provides factors associated with the adjustments of the minimum and maximum pump curves. These factors are:

- The magnitude of the adjustment will vary with pump flow rate since the adjustment is a function of flow, change in head, and the rate of change of pump developed head with flow

- The uncertainty in pump speed is greater than zero since the uncertainties in frequency and voltage are greater than zero

- The minimum allowable pump curve will be increased at each point by the calculated amount of total uncertainty in pump head for that flow point

- The maximum allowable pump curve will be decreased at each point by the calculated amount of total uncertainty in pump head for that flow point

- The magnitude of the adjustment will vary between the minimum and maximum pump curves since the adjustment is a function of the change in head and the rate of change of pump developed head with flow, both of which are a function of the pump curves

The NRC staff finds that these factors and no others affect the IST minimum and maximum allowable pump curves. Applying the total uncertainty in pump head to the pump minimum and maximum allowable pump curves will reduce the acceptable pump operation band between the curves.

3.4 Worked Example Problem

Section 2.4 of the TR is a worked example problem implementing the methodology contained in the TR to adjust the minimum allowable pump performance curve. The example uses underfrequency and undervoltage parameters only. Licensees will also have to perform similar calculations for overfrequency and overvoltage in order to adjust the maximum allowable pump performance curve. The example assumes a flow measurement uncertainty of the larger of either 10 gallons per minute or 2 percent of the flow rate (Section 2.4.1), a change in total head measurement uncertainty of 34.64 feet (Section 2.4.2), a governor frequency uncertainty of 0.25 Hz (Section 2.4.3), and a voltage regulator uncertainty of 100 V (Section 2.4.4). The example uses the equations presented in Section 2.2 of the TR to determine the overall uncertainty in pump total head change at various pump flow rates. Earlier in this SE, the NRC staff found the use of these equations to be acceptable. The NRC staff found no discrepancies in the methodology used in the worked example.

3.5 Motor Speed and Torque

The following relationships are generally used to determine the impact of voltage and frequency variations:

- Synchronous speed is directly proportional to frequency since the number of poles is constant. For an induction motor, the rotational speed lags the synchronous speed by a factor known as slip. The slip is usually less than 5 percent of synchronous speed.

- Horsepower varies directly with the cube of the speed

- The torque developed by a motor is proportional to the square of the terminal voltage

- The torque developed by a motor is inversely proportional to the square of the power supply frequency

NEMA MG 1-2014, Section 14.30, "Motors and Generators," provides the following guidelines for effects of variation of voltage and frequency on performance of induction motors:

> **General**
> Induction motors are at times operated on circuits of voltage or frequency other than those for which the motors are rated. Under such conditions, the performance of the motor will vary from the rating. The following are some of the operating results caused by small variations of voltage and frequency and are indicative of the general character of changes produced by such variation in operating conditions.
>
> **Effects of Variation in Voltage on Temperature**
> With a 10 percent increase or decrease in voltage from that given on the nameplate, the heating at rated horsepower load may increase. Such operation for extended periods of time may accelerate the deterioration of the insulation system.
>
> **Effect of Variation in Voltage on Power Factor**
> In a motor of normal characteristics at full rated horsepower load, a 10 percent increase of voltage above that given on the nameplate would usually result in a decided lowering in power factor. A 10 percent decrease of voltage below that given on the nameplate would usually give an increase in power factor.
>
> **Effect of Variation in Voltage on Starting Torques**
> The locked-rotor and breakdown torque will be proportional to the square of the voltage applied.
>
> **Effect of Variation in Voltage on Slip**
> An increase of 10 percent in voltage will result in a decrease of slip of about 17 percent, while a reduction of 10 percent will result in an increase of slip of about 21 percent. Thus, if the slip at rated voltage were 5 percent, it would be increased to 6.05 percent if the voltage were reduced 10 percent.
>
> **Effects of Variation in Frequency**
> A frequency higher than the rated frequency usually improves the power factor but decreases locked rotor torque and increases the speed and friction and windage loss. At a frequency lower than the rated frequency, the speed is decreased, locked-rotor torque is increased, and power factor is decreased. For certain kinds of motor load, such as in textile mills, close frequency regulation is essential.

Effect of Variations in Both Voltage and Frequency
If variations in both voltage and frequency occur simultaneously, the effect will be superimposed. Thus, if the voltage is high and the frequency low, the locked-rotor torque will be very greatly increased, but the power factor will be decreased and the temperature rise increased with normal load.

Effect on Special-Purpose or Small Motors
The foregoing facts apply particularly to general-purpose motors. They may not always be true in connection with special-purpose motors, built for a particular purpose, or for very small motors.

Performance within these voltage and frequency variations will not necessarily be in accordance with the standards and specifications used by licensee for procurement of Class 1E motors considered for operation at rated voltage and frequency. In fact, they could reduce the motor life significantly.

Section 2.5.3 of the TR evaluates the impact on motor torque due to speed, frequency, and voltage variations. The approach uses algorithms to approximate the change in steady-state speed as a result of voltage and frequency variations. The net effect of voltage and frequency variations on steady-state speed can be approximated as the sum of the change due to voltage plus the sum of the change due to frequency. Based on the assumption that the operating region of a typical pump motor speed-torque curve is approximately linear from the point of maximum torque to the end of the curve at synchronous speed, evaluation considers the change in operating speed is proportional to the change in frequency. Using these approximations, the operating point of a motor used to drive a pump is established and the capability evaluated. The TR concludes that:

- For most pump-motor sets applications, the motor torque-speed curve has a sufficiently steep slope that the error is small; and

- Although the slope also changes slightly as a result of the frequency change, this effect is negligible for small variations (less than 5 Hz)

The approach proposed in the TR is generally acceptable if the design of motors and operating pumps are in general agreement with the assumptions and there is adequate margin in the motor/pump sizing criterion. The NRC staff notes that motors operating at lower or higher than normal frequency will operate at a different point on the torque/speed curve and also have a different power factor resulting in change in real and reactive components of load current. Similarly, motors operating at lower (or higher) voltage will have higher current which may result in heating up the motor windings during extended operation. Hence, if the margin between nominal motor rating and load requirements or margin between fluid flow rates assumed in accident analyses and pump capability at nominal frequency and voltage is small, then the errors assumed to be negligible in the TR methodology should not be discounted and detailed analyses performed to demonstrate the capability of pump(s) and motor(s) operating at extremes of allowable range. In addition, if the motors are designed with a service factor above 1.0 and pumps can deliver flow at run out conditions, the worst-case loading condition must be considered by the licensees in their EDG loading conditions.

3.6 Impact of Frequency Variation on Diesel Generator Loading

Section 3.1.1 of the TR evaluates the impact of frequency variation on DG loading. The method assumes that:

- The entire DG loading is inductive

- An under frequency would not negatively impact DG loading calculations

- The increase in DG inductive power load associated with the increase in frequency is obtained by cubing the ratio of maximum frequency divided by nominal frequency

The TR concludes that the calculated change in load will be added to the load calculations to account for maximum DG frequency and the total DG loading evaluated to ensure that it does not exceed the DG rating. The NRC staff agrees that plant DG loading should be corrected due to change in operating frequency and TS should be amended accordingly to reflect the change in DG loading due to allowable frequency variation.

3.7 Impact of Voltage Variation on Diesel Generator Loading

Section 3.1.2 of the TR evaluates the impact of voltage variation on DG loading. The TR states that the effect of voltage variation from the nominal voltage rating of the DG would cause the current of the motor load circuits to decrease or increase accordingly and there would be no net change in the power required by and delivered to the loads from the DG. This rationale is acceptable when DG power output is considered in terms of Volt-Amps. However, when rotating motors operate at lower than nominal voltage and frequency, there is a change in the power factor and real and reactive portions of the current. Since the real power is a function of the governor controls and reactive power is controlled by DG exciter and voltage regulator, the overall impact of DG output voltage should be considered for real and reactive components of DG loading evaluation.

3.8 Impact on Diesel Generator Fuel Oil and Lube Oil Consumption and Storage Requirements

STS Section 3.8.3 delineates requirements for onsite storage of DG fuel oil, lube oil, and starting air. As indicated in Section 3.2 of the TR, the calculated change in DG loading due to steady-state variation in voltage and frequency should require a commensurate evaluation of the impact on fuel oil consumption as a result of the change in loading. The plant-specific TS associated with these requirements should be revised.

3.9 Impact of Frequency Variation on Motor-Operated Valve Operation

Section 4.1 of the TR evaluates the impact on MOV stroke time due to frequency changes. An example using a MOV stroke time of 10 seconds and a maximum DG frequency deviation 0.35 Hz is used to illustrate that the change in valve stroke time is less than 0.6 percent. The TR concludes that the impact of reduced valve stroke time caused by a decrease in motor speed due to lower than nominal frequency, will not affect the valve performance in an adverse manner. The NRC staff agrees that in the example considered, the deviation in stroke time is negligible. However, the NRC staff notes that there is a large population of MOVs in the nuclear power plants with stroke times as long as 25 – 30 seconds and not all licensees may be able to control the DG frequency within ±0.35 Hz. In such cases, plant specific evaluations may be required to demonstrate that the change in MOV stroke time does not impact fluid flow assumptions in safety analyses.

3.10 Impact of Frequency Change on Motor-Operated Valve Inertia

The inertia of a MOV is associated with the moving parts of the valve assembly and consists of the sum of the inertias of the motor, the gear train, and the stem-disc assembly. Section 4.2 of the TR lists standard equations for rotational energy, work, equivalent inertia, and change in energy in order to provide an equation for the change in inertia effect due to frequency change. Section 4.2.1 provides a worked example of the impact of frequency change on MOV inertia. The example shows that an increase in frequency of 0.5 Hz increases a 4,000 pound inertia effect by 66.7 pounds, or 1.7 percent.

The NRC staff finds the methodology in the TR, using standard equations to calculate the change in inertia effect from a change in frequency, to be acceptable. As shown in the worked example, the change in inertia effect is very small and will not impact the valve performance in an adverse manner.

3.11 Impact of Voltage Variation on Motor-Operated Valve Operation

In response to Generic Letter (GL) 96-05, “Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves,” and GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," licensees should have evaluated the performance capabilities of MOVs under degraded voltage conditions. Therefore the NRC staff accepts the discussion in Section 4.3 of the TR which concludes that for typical AC motor and actuator applications, voltage variation from 90 – 100 percent will not affect the MOV output torque outside its operating range if the nominal ratings are used. The licensees should verify that the plant specific MOV analysis is bounded by the allowable DG output voltage variation.

3.12 Impact of Pump Output Pressure/Differential Pressure on the Motor-Operated Valve

An increase in pump discharge pressure, and, consequently the differential pressure (DP) caused by a higher than nominal frequency will create a higher DP at an MOV. Section 4.4 of the TR provides conditions that need to be satisfied for any MOV calculation done at a DP lower than the pump shutoff head, to ensure that the MOV remains operable. The NRC staff finds the conditions specified to be acceptable, because the margin evaluation guidelines of MPR-2524-A, “Joint Owners’ Group (JOG) Motor Operated Valve Periodic Verification Program Summary,” Revision 1, dated September 2010 (ADAMS Accession Nos. ML110680188 and ML110680193) are followed.

3.13 Example Technical Specification Mark Up

Appendix A of the TR identifies typical TS changes that could be considered by licensees after modifying DG allowable voltage and frequency range to a value within the capabilities of the plant specific machines. The NRC staff notes that the voltage and frequency requirements in TS SR 3.8.1.2 are proposed to be deleted. The intent is to allow licensees to define a range of allowable voltage and frequency within a nominal band. The NRC staff does not agree with

(1) the deletion of allowable voltage and frequency requirements in SR 3.8.1.2 and (2) the deletion of the second sentence of Note 2.

Note 2 of SR 3.8.1.2 allows a modified start of the DG if recommended by the DG manufacturer. The second sentence stipulates that the time, voltage, and frequency requirements of SR 3.8.1.7 apply when modified start procedures are not used. The proposed modifications of SR 3.8.1.2 removed the second sentence of Note 2 with no explanation or apparent consideration as to the recommendations of DG manufacturers. In RAI responses dated August 31, 2015 (ADAMS Accession No. ML15247A070), the PWROG stated that SR 3.8.1.2 "… can be performed in a slow start mode and is therefore not intended to be a design basis test, but rather a functionality test …." The NRC staff examined historical STS and determined that the 31 day SR has been the SR where time, voltage, and frequency requirements have applied. The 31 day SR historically precedes the 184 day SR.

The NRC staff considers all SRs in TS 3.8.1 associated with the DG demonstrate operability and readiness of the DG to perform its functions as delineated in the safety analyses. The NRC staff believes that the frequency and voltage requirements in SR 3.8.1.2 (and SR 3.8.1.7) specified for slow and fast starts (irrespective of automatic or manual control) also demonstrate the operability of the EDG (as defined in STS) to support its required functions and should therefore, be maintained in accordance with assumptions in accident analyses. The NRC staff finds the reasoning to support the TS SR language change to SR 3.8.1.2 inadequate for the reasons stated above.

Otherwise, the NRC staff finds that the TS changes proposed in Appendix A and SR acceptance criteria numerical changes are acceptable examples and in agreement with the stated methodology.

4.0 LIMITATIONS AND CONDITIONS

The TR does not discuss the impact of low voltage/frequency on non-inductive loads such as heaters, battery chargers hydrogen igniters, uninterruptible power supplies (UPS) etc. It is expected that such equipment will continue to function, but the capability to maintain design conditions should be verified. As an example, UPS systems generate AC output at the desired 60 Hz frequency and constantly monitor the frequency on the bypass supply to allow a seamless automatic transfer. If the bypass supply frequency, as maintained by the DG, is not within the tolerances of the UPS design, then the transfer to the bypass supply is prohibited. Licensees crediting equipment such as pressurizer heaters, room heaters, hydrogen igniters, etc. in certain AOOs or accident conditions should evaluate adequacy of the equipment operating with low DG bus voltage.

5.0 CONCLUSION

The NRC staff has reviewed the PWROG proposed methodology for evaluating DG performance, ECCS equipment operating capabilities, and TS changes. The NRC staff is in general agreement with the methodology prescribed in TR WCAP-17308-NP, Revision 0, for demonstrating adequacy of plant systems used to mitigate the consequences of an accident when the onsite sources are operating at the extremes of allowable frequency and voltage. The NRC staff agrees that a properly operating governor and voltage regulator of a DG should be able to control the output voltage and frequency around a nominal value within the manufacturer's specified tolerances. The TS SR for demonstrating the capability of the DGs to function as required should be amended according to the licensee established parameters for DG steady state voltage and frequency. The licensees should evaluate the impact of frequency and voltage variation in the applicable operating range considered TS for equipment supplied by the DGs during postulated DBAs and anticipated operational occurrences. Based on the evaluation discussed above, the NRC staff determined that the proposed TR methodology related to the allowable steady state operating voltage and frequency band of the DGs is generally acceptable for plants with operating margin in (1) DG rating and (2) ECCS equipment capabilities. Plants that have equipment with marginal capabilities should perform detailed analyses to evaluate the performance of ECCS components at the allowable frequency and voltage range to demonstrate the adequacy of the equipment to function within the assumptions used in accident analyses. The NRC staff also concludes that the proposed TR methodology, when correctly implemented, will provide assurance that the plant maintains compliance with requirements in 10 CFR 50.36(c)(3), GDC 17, and CDC 18 governing the design and operation of the onsite electrical power systems and provides adequate assurance of safety system operability. Therefore, the NRC staff finds the proposed TR methodology acceptable, with noted limitations and conditions, for compliance with the NRC regulations.

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Date: February 12, 2016