Duke Power
A Duke Energy Company

Gary R. Peterson
Vice President

Duke Power
Catawba Nuclear Station
4800 Concord Road
York, SC 29745
(803) 831-4251 OFFICE
(803) 831-3221 FAX

March 1, 2001

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

Subject: Duke Energy Corporation
Catawba Nuclear Station, Units 1 and 2
Docket Nos. 50-413 and 50-414
Technical Specification Bases Changes

Pursuant to 10CFR 50.4, please find attached changes to the Catawba Nuclear Station Technical Specification Bases. These Bases changes were made according to the provisions of 10CFR 50.59.

Any questions regarding this information should be directed to L. J. Rudy, Regulatory Compliance, at (803) 831-3084.

I certify that I am a duly authorized officer of Duke Energy Corporation and that the information contained herein accurately represents changes made to the Technical Specification Bases since the previous submittal.

Gary R. Peterson

Attachment

A001

xc: L. A. Reyes, Regional Administrator
U. S. Nuclear Regulatory Commission, Region II

C. P. Patel, Project Manager
U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation, Mail Stop 0-8 H12

D. J. Roberts
Senior Resident Inspector
Catawba Nuclear Station

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY are established in LCO 3.1.4, "Rod Group Alignment Limits," and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Digital Rod Position Indication (DRPI) System.

BASES

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The DRPI System provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is 6 steps. To increase the reliability of the system, the inductive coils are connected alternately to data system A or B. Thus creating two separate and independent systems (Data A and Data B). Also, the coils are not placed at the reflected six step increments starting at rod bottom. Because of this arrangement, the nominal accuracy of the system is + 3 steps indicated versus true rod position. Due to mechanical positioning of the coils on the rod position detector and expansion in containment atmosphere, another + 1 step is added to system accuracy making it + 4 steps.

If one system fails, the DRPI will go to half accuracy. If Data A fails, the accuracy will be + 10, - 4 steps. If Data B fails, the accuracy will be - 10, + 4 steps. Therefore, the maximum deviation between the group demand counters and DRPI could be 10 steps, or 6.25 inches.

Gray code (A & B data from the data cabinets in containment) is sent to the DRPI equipment in the control room. The gray code is processed by the DRPI equipment and the rod position is displayed on the control board. The gray code is also sent from the DRPI equipment to the Operator Aid Computer (OAC), where it is processed by the OAC and the rod position is displayed on the OAC. The processing of the gray code by the DRPI equipment and the OAC are completely independent. Therefore, both the DRPI display and the OAC DRPI indication are considered valid indications of control rod position.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod

BASES

APPLICABLE SAFETY ANALYSES (continued)

worth, and with at least minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36 (Ref. 3). The control rod position indicators monitor control rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that one DRPI System and one Bank Demand Position Indication System be OPERABLE for each control rod. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The DRPI System indicates within 12 steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits";

b. For the DRPI System there are no failed coils; and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the DRPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the DRPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

BASES

APPLICABILITY

The requirements on the DRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

A.1

When one DRPI channel per group fails, the position of the rod can still be determined by use of the incore movable detectors. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of B.1 or B.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 4).

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1 and B.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required

ACTIONS (continued)

Actions of A.1 and A.2 are still appropriate but must be initiated promptly under Required Action B.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

C.1.1 and C.1.2

With one demand position indicator per bank inoperable, the rod positions can be determined by the DRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart within the allowed Completion Time of once every 8 hours is adequate. Since DRPI is the only operable rod position indication, administrative means are actions taken by the control room SRO to assure that the DRPI for the affected bank remains operable at all times. These administrative means would prevent any maintenance or testing of the operable DRPI for the affected bank until the inoperable demand position indicator is returned to operable status.

C.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits (Ref. 4). The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the

BASES

ACTIONS (continued)

required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the DRPI agrees with the demand position within 12 steps ensures that the DRPI is operating correctly.

This Surveillance is performed prior to reactor criticality after each removal of the reactor head as there is the potential for unnecessary plant transients if the SR were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 13.
2. UFSAR, Section 15.0.
3. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
4. UFSAR, Section 15.4

ACTIONS (continued)

L.1

Condition L applies to the Doghouse Water Level - High High.

The failure of one channel in either reactor building doghouse results in a loss of redundancy for the function and possible feedwater isolation (depending on the failed status of the channel). This requires the unit be placed in MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, this Function is no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 2 hours for surveillance testing of other channels.

M.1, M.2.1 and M.2.2

Condition M applies to the Auxiliary Feedwater Pumps Suction Transfer on Suction Pressure Low.

If one channel is inoperable, 1 hour is allowed to restore the channel to OPERABLE status or to place it in the tripped condition. The failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-three configuration that satisfies redundancy requirements.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 1 hour requires the unit to be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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 unit systems. In MODE 4, this Function is no longer required OPERABLE.

ACTIONS (continued)

N.1, N.2.1 and N.2.2

Condition N applies to:

- RWST Level—Low Coincident with Safety Injection.

RWST Level—Low Coincident With SI provides actuation of switchover to the containment sump. Note that this Function requires the bistables to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function. However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required. Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 6 hours is sufficient to ensure that the Function remains OPERABLE, and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 6 hour Completion Time is justified in Reference 7. If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 6 hours, the unit must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 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 unit systems. In MODE 5, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows placing a second channel in the bypass condition for up to 2 hours for surveillance testing. The total of 12 hours to reach MODE 3 and 2 hours for a second channel to be bypassed is acceptable based on the results of Reference 7.

BASES

SURVEILLANCE REQUIREMENTS (continued)

LEAKAGE are determined by performance of an RCS water inventory balance. Primary to secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and feedwater systems. For this SR, the volumetric calculation of unidentified LEAKAGE and identified LEAKAGE is based on a density at room temperature of 77 degrees F. The volumetric calculation of primary to secondary LEAKAGE is based on a density at operating RCS temperature of 585 degrees F.

The RCS water inventory balance must be performed with the reactor at steady state operating conditions and near operating pressure. Therefore, this SR is not required to be completed in MODES 3 and 4 until 12 hours of steady state operation near operating pressure have been established.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. A Note under the Frequency column states that this SR is required to be performed during steady state operation.

SR 3.4.13.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, May 1973.
3. UFSAR, Section 15.
4. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere following an event which has the potential to result in a net external pressure on the containment.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer codes designed to predict the resultant containment pressure transients. The worst case LOCA generates larger mass and energy release than the worst case SLB. Thus, the LOCA event bounds the SLB event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 15.0 psia (0.3 psig). The containment analysis (Ref. 1) shows that the maximum peak calculated containment pressure, P_a, results from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA does not exceed the containment design pressure, 15.0 psig.

The containment was also designed for an external pressure load equivalent to -1.5 psig.

BASES

APPLICABLE SAFETY ANALYSES (continued)

There are five conditions which have a potential for resulting in a net external pressure on the containment:

1. Rupture of a hot or high pressure process pipe in the annulus.

2. Inadvertent Containment Spray System initiation during normal operation.

3. Inadvertent containment air return fan initiation during normal operation.

4. Containment purge fan operation with containment purge inlet valves closed.

5. Containment air release fan pressure controller failure resulting in fan not shutting off properly.

The containment design of 1.5 psig negative is not exceeded in the first four conditions due to either equipment limitations or design features, but may be exceeded in the fifth case. The containment air release fan is capable of pulling a negative pressure in containment beyond design limits if allowed to run unchecked. Administrative controls prevent this event from occurring. The Operator Aid Computer (OAC) response to a low pressure alarm ensures a Containment Air Release and Addition System release is terminated, if in progress, and in cases where the OAC is inoperable, the pressure is monitored on a 30-minute frequency during releases. These controls are utilized to ensure the pressure stays within the Technical Specification limit of 0.1 psig negative.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of 10 CFR 50.36 (Ref. 3).

BASES

SURVEILLANCE REQUIREMENTS (continued)

OPERABILITY. The allowance of one inoperable hydrogen ignitor is acceptable because, although one inoperable hydrogen ignitor in a region would compromise redundancy in that region, the containment regions are interconnected so that ignition in one region would cause burning to progress to the others (i.e., there is overlap in each hydrogen ignitor's effectiveness between regions). The Frequency of 92 days has been shown to be acceptable through operating experience.

SR 3.6.9.2

This SR confirms that the two inoperable hydrogen ignitors allowed by SR 3.6.9.1 (i.e., one in each train) are not in the same containment region*. The Frequency of 92 days is acceptable based on the Frequency of SR 3.6.9.1, which provides the information for performing this SR.

SR 3.6.9.3

A more detailed functional test is performed every 18 months to verify system OPERABILITY. Each glow plug is visually examined to ensure that it is clean and that the electrical circuitry is energized. All ignitors (glow plugs), including normally inaccessible ignitors, are visually checked for a glow to verify that they are energized. Additionally, the surface temperature of each glow plug is measured to be $\geq$ 1700°F to demonstrate that a temperature sufficient for ignition is achieved*. The 1700°F temperature is a surveillance requirement. "An Analysis of Hydrogen Control Measures at McGuire Nuclear Station" (Ref. 5) section 3.8 identifies that the required normal operation temperature is 1500°F. Therefore, based upon ignitor performance testing conducted at Catawba, the surveillance requirement of 1700°F ensures that sufficient margin is present for continued hydrogen ignition under degraded bus conditions. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

* For Unit 2 Cycle 11 operation only, or until the next Unit 2 entry into MODE 5 which allows affected ignitor replacement, this SR is not applicable to each train's ignitor located beneath the reactor vessel missile shield.

BASES

REFERENCES

1. 10 CFR 50.44.

2. 10 CFR 50, Appendix A, GDC 41.

3. UFSAR, Section 6.2.

4. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

5. An Analysis of Hydrogen Control Measures at McGuire Nuclear Station.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Essential Auxiliary Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternate(s)), and the onsite standby power sources (Train A and Train B diesel generators (DGs)). 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 onsite Class 1E AC Distribution System is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two preferred offsite power sources and a single DG.

From the transmission network, two electrically and physically separated circuits provide AC power, through step down station auxiliary transformers, to the 4.16 kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

A qualified 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 Class 1E ESF bus(es).

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 Class 1E 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 the load sequencer.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs A and B are dedicated to ESF buses ETA and ETB, respectively. A DG starts automatically on a safety injection (SI) signal

BACKGROUND (continued)

(i.e., low pressurizer pressure or high containment pressure signals) 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 undervoltage or degraded voltage, independent of or coincident with an SI signal. With no SI signal, there is a 10 minute delay between degraded voltage signal and the DG start signal. 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, a sequencer strips 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 the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of preferred power, 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. Approximately 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 Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 7000 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (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.

BASES

APPLICABLE SAFETY ANALYSES (continued)

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 one train of the onsite or offsite AC sources OPERABLE 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 (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the onsite Essential Auxiliary 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, one required automatic load sequencer per train must be OPERABLE.

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.

The 4.16 kV essential system is divided into two completely redundant and independent trains designated A and B, each consisting of one 4.16 kV switchgear assembly, three 4.16 kV/600 V transformers, two 600 V load centers, and associated loads.

Normally, each Class 1E 4.16 kV switchgear is powered from its associated non-Class 1E train of the 6.9 kV Normal Auxiliary Power System as discussed in "6.9 kV Normal Auxiliary Power System" in Chapter 8 of the UFSAR (Ref. 2). Additionally, an alternate source of power to each 4.16 kV essential switchgear is provided from the 6.9 kV system via two separate and independent 6.9/4.16 kV transformers. These transformers are shared between units and provide the capability

BASES

LCO (continued)

to supply an alternate source of preferred power to each unit's 4.16 kV essential switchgear from either unit's 6.9 kV system. A key interlock scheme is provided to preclude the possibility of connecting the two units together at either the 6.9 or 4.16 kV level.

Each train of the 4.16 kV Essential Auxiliary Power System is also provided with a separate and independent emergency diesel generator to supply the Class 1E loads required to safely shut down the unit following a design basis accident. Additionally, each diesel generator is capable of supplying its associated 4.16 kV blackout switchgear through a connection with the 4.16 kV essential switchgear.

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 11 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. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

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

The AC sources in one 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 provided to the extent practical.

APPLICABILITY

The AC sources and sequencers 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. UFSAR, Chapter 8.
3. Regulatory Guide 1.9, Rev. 2, December 1979.
4. UFSAR, Chapter 6.
5. UFSAR, Chapter 15.
6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
7. Regulatory Guide 1.93, Rev. 0, December 1974.
8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
9. 10 CFR 50, Appendix A, GDC 18.
10. Regulatory Guide 1.108, Rev. 1, August 1977 (Supplement September 1977).
11. Regulatory Guide 1.137, Rev. 1, October 1979.
12. ASME, Boiler and Pressure Vessel Code, Section XI.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.7

This SR requires that each battery charger for the DC channel be capable of supplying at least 200 amps and at least 75 amps for the DG chargers. All chargers shall be tested at a voltage of at least 125 V for ≥ 8 hours. These requirements are based on the design capacity of the chargers (Ref. 4). According to Regulatory Guide 1.32 (Ref. 10), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

SR 3.8.4.8

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 4. The DC channel batteries are tested to supply a current ≥ 522.14 amps for the first minute, then ≥ 267.71 amps for the next 9 minutes, ≥ 376.15 amps for the next 10 minutes, and ≥ 281.94 amps for the next 100 minutes. Terminal voltage is required to remain ≥ 110.4 volts during this test. The DG batteries are tested to supply a current ≥ 171.6 amps for the first minute, then ≥ 42.5 amps for the remaining 119 minutes. Terminal voltage is required to remain ≥ 105 volts during this test.

Except for performing SR 3.8.4.8 for the DC channel batteries with the unit on line, the Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 10), which states that the battery service test should be performed during refueling operations or at some other outage, with intervals between tests, not to exceed 18 months.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test once per 60 months.

SURVEILLANCE REQUIREMENTS (continued)

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test. The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

SR 3.8.4.9

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is described in the Bases for SR 3.8.4.8. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.9; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.9 while satisfying the requirements of SR 3.8.4.8 at the same time.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 9). This reference recommends that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.