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7.0 INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

This chapter presents the various plant instrumentation and control systems by relating the functional performance requirements, design bases, system descriptions, design evaluations, and tests and inspections for each. The information provided in this chapter emphasizes those instruments and associated equipment which constitute the protection system as defined in IEEE Standard 279-1971 "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations," Reference [1].

The primary purpose of the instrumentation and control systems is to provide automatic protection and exercise proper control against unsafe and improper reactor operation during steady-state and transient power operations (ANS Conditions I, II, III) and to provide initiating signals to mitigate the consequences of faulted conditions (ANS Condition IV). ANS conditions are discussed in Chapter 15. Consequently, the information presented in this chapter emphasizes those instrumentation and control systems which are central to assuring that the reactor can be operated to produce power in a manner that ensures no undue risk to the health and safety of the public.

It is shown that the applicable criteria and codes, such as General Design Criteria and IEEE Standards, concerned with the safe generation of nuclear power are met by these systems. See Table 7.1-1 for a listing of applicable criteria.

Terminology used in this chapter is based on the definitions given in IEEE Standard 279-1971 which is listed in Table 7.1-1. In addition, the following definitions apply:

1. Degree of Redundancy

   The difference between the number of channels monitoring a variable and the number of channels which when tripped, will cause an automatic system trip.

2. Minimum Degree of Redundancy

   The degree of redundancy below which operation is prohibited, or otherwise restricted by the Technical Specifications.

3. Cold Shutdown Condition

   When the reactor is subcritical by at least 1 percent $\Delta k/k$ and T_{avg} is $\leq$ 200°F.

4. Hot Shutdown Condition

   When the reactor is subcritical, by an amount greater than or equal to the margin specified in the applicable Technical Specification and T_{avg} is in the range specified in the applicable Technical Specification.

5. Phase A Containment Isolation

   Closure of all nonessential process lines which penetrate the Reactor Building, except engineered safety features lines, component cooling lines and steam lines into and out of the Reactor Building, initiated by the safety injection signal, or manually.

6. Phase B Containment Isolation

   Closure of remaining process lines, initiated by Reactor Building Hi-3 pressure signal or manually (process lines do not include engineered safety features lines). Steam lines will previously have been closed by Reactor Building Hi-2 pressure signal.

7. System Response Times

   a. Reactor Trip System Response Time

      The Reactor Trip System response time shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until loss of stationary gripper coil voltage.

   b. Engineered Safety Features Actuation System Response Time

      The Engineered Safety Features Actuation System response time shall be that time interval from when the monitored parameter exceeds its engineered safety features actuation setpoint at the channel sensor until the engineered safety features equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable.

8. Reproducibility

   This definition is taken from Scientific Apparatus Manufactures Association (SAMA) Standard PMC-20.2-1973, Process Measurement and Control Terminology: "the closeness of agreement among repeated measurements of the output for the same value of input, under normal operating conditions over a period of time, approaching from both directions." It includes drift due to environmental effects, hysteresis, long term drift, and repeatability. Long term drift (aging of components, etc.) is not an important factor in accuracy requirements since, in general, the drift is not significant with respect to the time elapsed between testing. Therefore, long term drift may be eliminated from this definition. Reproducibility, in most cases, is a part of the definition of accuracy (see item 9).

9. Accuracy

This definition is derived from Scientific Apparatus Manufactures Association (SAMA) Standard PMC-20.2-1973, Process Measurement and Control Terminology. An accuracy statement for a device falls under Note 2 of the Scientific Apparatus Manufactures Association definition of accuracy, which means reference accuracy or the accuracy of that device at reference operating conditions: "Reference accuracy includes conformity, hysteresis and repeatability." To adequately define the accuracy of a system, the term reproducibility is useful as it covers normal operating conditions. The following terms, "trip accuracy" and "indicated accuracy," etc., will then include conformity and reproducibility under normal operating conditions. Where the final result does not have to conform to an actual process variable but is related to another value established by testing, conformity may be eliminated, and the term reproducibility may be substituted for accuracy. 00-01

10. Normal Operating Conditions

Normal operating conditions include normal process temperature and pressure changes, and ambient temperature changes around the transmitter and racks. The normal operating conditions exclude those parameters experienced under post accident conditions. 99-01

11. Readout Devices

For consistency the final device of a complete channel is considered a readout device. This includes indicators, recorders, and controllers.

12. Channel Accuracy

This definition includes accuracy of primary element, transmitter and rack modules. It does not include readout devices or rack environmental effects, but does include process and environmental effects on field mounted hardware. Rack environmental effects are included in the next 2 definitions to avoid duplication due to dual inputs.

13. Indicated and/or Recorded Accuracy

This definition includes channel accuracy, accuracy of readout devices and rack environmental effects.

14. Trip Accuracy

    This definition includes comparator accuracy, channel accuracy, for each input, and rack environmental effects. This is the tolerance expressed in process terms (or percent or span) within which the complete channel must perform its intended trip function. This includes all instrument errors but no process effects such as streaming. The term "actuation accuracy" may be used where the word "trip" might cause confusion (for example, when starting pumps and other equipment).

15. Control Accuracy

    This definition includes channel accuracy, accuracy of readout devices (isolator, controller), and rack environmental effects. Where an isolator separates control and protection signals, the isolator accuracy is added to the channel accuracy to determine control accuracy, but credit is taken for tuning beyond this point; i.e., the accuracy of these modules (excluding controllers) is included in the original channel accuracy. It is simply defined as the accuracy of the control signal in percent of the span of that signal. This will then include gain changes where the control span is different from the span of the measured variable. Where controllers are involved, the control span is the input span of the controller. No error is included for the time in which the system is in a non-steady-state condition.

7.1.1 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

7.1.1.1 <u>Safety-Related Systems</u>

The Nuclear Steam Supply System (NSSS) instrumentation discussed in Chapter 7 that is required to function to achieve the system responses assumed in the safety evaluations, and those needed to shutdown the plant safely are given in this section. Table 7.1-2 identifies safety related instrumentation and control systems.

7.1.1.1.1 Reactor Trip System

The Reactor Trip System is a functionally defined system described in Section 7.2. The equipment which provides the trip functions is identified and discussed in Section 7.2. Design bases for the Reactor Trip System are given in Section 7.1.2.1. Figure 7.1-1 includes a single line diagram of this system. Additional background information on the Reactor Trip System is contained in Reference [2].

7.1.1.1.2 Engineered Safety Features Actuation System

The Engineered Safety Features Actuation System is a functionally defined system described in Section 7.3. The equipment which provides the actuation functions is identified and discussed in Section 7.3. Design bases for the Engineered Safety Features Actuation System are given in Section 7.1.2.1.

7.1.1.1.3 Instrumentation and Control Power Supply System

Design bases for the Instrumentation and Control Power Supply System are given in Section 7.1.2.1. Further description of this system is provided in Section 7.6.1.

7.1.1.2 <u>Safety-Related Display Instrumentation</u>

Display instrumentation provides the operator with information to enable him to monitor the results of engineered safety features actions following a Condition II, III, or IV event. Section 7.5 describes the instrumentation required to maintain the plant in a hot shutdown condition or to proceed to cold shutdown. 00-01

7.1.1.3 <u>Instrumentation and Control System Designers</u>

Systems discussed in Chapter 7 have definitive functional requirements developed on the basis of the Westinghouse Nuclear Steam Supply System design. Figure 7.2-1 defines scope interface. Regardless of the supplier, the functional requirements necessary to assure plant safety and proper control are clearly delineated.

7.1.1.4 <u>Plant Comparison</u>

System functions for all systems discussed in Chapter 7 are similar to those of the Joseph M. Farley Nuclear Plant. A comparison table is provided in Section 1.3.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

Section 7.1.2.1 gives design bases for the systems given in Section 7.1.1.1. Design bases for non-safety related systems are provided in the sections which describe the systems. Conservative considerations for instrument errors are included in the accident analyses presented in Chapter 15. Functional requirements, developed on the basis of the results of the accident analyses, which have utilized conservative assumptions and parameters are used in designing these systems and a preoperational testing program verifies the adequacy of the design. Accuracies are given in Sections 7.2, 7.3, and 7.5.

The documents listed in Table 7.1-1 were considered in the design of the systems given in Section 7.1.1. In general, the scope of these documents is given in the document itself. This determines the systems or parts of systems to which the document is applicable. A discussion of compliance with each document for systems in its scope is provided in the referenced sections given in Table 7.1-1 for each criterion. Because some documents were issued after design and testing had been completed, the equipment documentation may not meet the format requirements of some standards. Justification for any exceptions taken to each document for systems in its scope is provided in the referenced sections.

Table 7.1-2 outlines the design criteria that have been implemented in the design of safety related instrument and control systems.

7.1.2.1 Design Bases

7.1.2.1.1 Reactor Trip System

The Reactor Trip System acts to limit the consequences of Condition II events (faults of moderate frequency), such as loss of feedwater flow, by, at most, a shutdown of the reactor and turbine, with the plant capable of returning to operation after corrective action. The Reactor Trip System features impose a limiting boundary region to plant operation which ensures that the reactor safety limits are not exceeded during Condition II events and that these events can be accommodated without developing into more severe conditions. Reactor trip setpoints are given in the Technical Specifications.

The design requirements for the Reactor Trip System are derived by analyses of plant operating and fault conditions where automatic rapid control rod insertion is necessary in order to prevent or limit core or reactor coolant boundary damage. The design bases addressed in IEEE Standard 279-1971 are discussed in Section 7.2.1. The design limits specified by Westinghouse for the Reactor Trip System are:

1. There shall be at least a 95% probability (at a 95% confidence level) that departure from nucleate boiling (DNB) will not occur as a result of any anticipated transient or malfunction (Condition II faults).

2. Power density shall not exceed the rated linear power density for Condition II faults. See Chapter 4 for fuel design limits.

3. The stress limit of the Reactor Coolant System for the various conditions shall be as specified in Chapter 5.

4. Release of radioactive material shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius as a result of any Condition III fault.

5. For any Condition IV fault, release of radioactive material shall not result in an undue risk to public health and safety.

7.1.2.1.2 Engineered Safety Features Actuation System

The Engineered Safety Features Actuation System acts to limit the consequences of Condition III events (infrequent faults such as primary coolant spillage from a small rupture which exceeds normal charging system makeup and requires actuation of the Safety Injection System). The Engineered Safety Features Actuation System acts to mitigate Condition IV events (limiting faults, which include the potential for significant release of radioactive material).

The design bases for the Engineered Safety Features Actuation System are derived from the design bases given in Chapter 6 for the engineered safety features. Design bases requirements of IEEE Standard 279-1971 are addressed in Section 7.3.1.2. General design requirements are given below:

1. Automatic Actuation Requirements

   The primary requirement of the Engineered Safety Features Actuation System is to receive input signals (information) from the various on-going processes within the reactor plant and containment and automatically provide, as output, timely and effective signals to actuate the various components and subsystems comprising the Engineered Safety Features System.

2. Manual Actuation Requirements

   The Engineered Safety Features Actuation System must have provisions in the control room for manually initiating the functions of the Engineered Safety Features System.

7.1.2.1.3 Instrumentation and Control Power Supply System

The Instrumentation and Control Power Supply System provides continuous, reliable, regulated single phase a-c power to all instrumentation and control equipment required for plant safety. Details of this system are provided in Section 7.6. The design bases are given below:

1. The inverter shall have the capacity and regulation required for the a-c output for proper operation of the equipment supplied.

2. Redundant loads shall be assigned to different distribution panels which are supplied from different inverters.

3. Auxiliary devices that are required to operate dependent equipment shall be supplied from the same distribution panel to prevent the loss of electric power in one protection set from causing the loss of equipment in another protection set. No single failure shall cause a loss of power supply to more than one distribution panel.

4. Each of the distribution panels shall have access only to its respective inverter supply and a standby power supply.

5. The system shall comply with IEEE Standard 308-1971, paragraph 5.4.

7.1.2.1.4 Emergency Power

Design bases and system description for the emergency power supply are provided in Chapter 8.

7.1.2.1.5 Interlocks

Interlocks are discussed in Sections 7.2, 7.3, 7.6, and 7.7. The Reactor Trip and Engineered Safety Features Actuation System protection (P) interlocks are given on Tables 7.2-2 and 7.3-3. The safety analyses demonstrate that even under conservative critical conditions for either postulated or hypothetical accidents, the protective systems ensures that the Nuclear Steam Supply System will be put into and maintained in a safe state following an ANS Condition II, III, or IV accident commensurate with applicable Technical Specifications and pertinent ANS Criteria. Therefore, the protective systems have been designed to meet IEEE Standard 279-1971 and are entirely redundant and separate, including all permissives and blocks. All blocks of a protective function are automatically cleared whenever the protective function would be required to function in accordance with General Design Criteria 20, 21, and 22 and paragraphs 4.11, 4.12 and 4.13 of IEEE Standard 279-1971. Control interlocks (C) are identified on Table 7.7-1. Because control interlocks are not safety-related, they have not been specifically designed to meet the requirements of IEEE Protection System Standards.

7.1.2.1.6 Bypasses

Bypasses of protective functions are designed to meet the requirements of IEEE Standard 279-1971, paragraphs 4.11, 4.12, 4.13, and 4.14. A discussion of bypasses provided is given in Sections 7.2 and 7.3.

7.1.2.1.7 Equipment Protection

The criteria for equipment protection are given in Chapter 3. Equipment related to safe operation of the plant is designed, constructed and installed to protect it from damage. This is accomplished by working to accepted standards and criteria aimed at providing reliable instrumentation which is available under varying conditions. As an example, certain equipment is seismically qualified in accordance with IEEE Standard 344-1971. During construction, independence and separation is achieved, as required by IEEE Standard 279-1971 and IEEE Standard 384-1974, either by barriers, physical separation or demonstration by test. This serves to protect against complete destruction of a system by fires, missiles or other natural hazards.

7.1.2.1.8 Diversity

Functional diversity has been designed into the system. Functional diversity is discussed in Reference [3]. The extent of diverse system variables has been evaluated for a wide variety of postulated accidents. Generally, 2 or more diverse protection functions would automatically occur to mitigate the consequences of an accident.

For example, there are automatic reactor trips based upon neutron flux measurements, reactor coolant loop temperature and flow measurements, steam generation level measurements, pressurizer pressure and level measurements, feedwater flow measurements, and reactor coolant pump underfrequency and undervoltage measurements, as well as manually, and by initiation of a safety injection signal or turbine trip. 00-01

Regarding the Engineered Safety Features Actuation System for a loss of coolant accident, a safety injection signal can be obtained manually or by automatic initiation from any one of the following diverse parameter measurements: 00-01

1. Low pressurizer pressure.

2. High Reactor Building pressure (Hi-1).

For a steam break accident, safety injection signal actuation is provided by:

1. Low steam line pressure.

2. High steam line differential pressure.

3. For a steam break inside Reactor Building, high Reactor Building pressure (Hi-1) provides an additional parameter for generation of the signal.

All of the above sets of signals are redundant and physically separated and meet the requirements of IEEE Standard 279-1971.

7.1.2.1.9 Bistable Trip Setpoints

Westinghouse specifies 3 setpoints applicable to reactor trip and engineered safety features actuation:

1. Safety limit setpoint.

2. Limiting setpoint.

3. Nominal setpoint.

The safety limit is the value assumed in the accident analysis and is the least conservative value.

The limiting setpoint is the Technical Specification value and is obtained by subtracting a safety margin from the safety limit. The safety margin accounts for instrument error, process uncertainties such as flow stratification and transport factor effects, etc.

The nominal setpoint is the value set into the equipment and is obtained by subtracting allowances for instrument drift and calibration uncertainty from the limiting setpoint. The nominal setpoint allows for the normal expected instrument setpoint drifts such that the Technical Specification limits will not be exceeded under normal operation.

The setpoints that require trip action are given in the Technical Specifications. A further discussion on setpoints is found in Section 7.2.2.2.1.

The trip setpoint is determined by factors other than the most accurate portion of the instrument's range. The safety limit setpoint is determined only by the accident analysis. As described above, allowance is then made for process uncertainties, instrument error, instrument drift, and calibration uncertainty to obtain the nominal setpoint value which is actually set into the equipment. The only requirement on the instrument's accuracy value is that over the instrument span, the error must always be less than or equal to the error value allowed in the accident analysis. The instrument does not need to be the most accurate at the setpoint value as long as it meets the minimum accuracy requirement. The accident analysis accounts for the expected errors at the actual setpoint.

Range selection for the instrumentation covers the expected range of the process variable being monitored consistent with its application. The design of the Reactor Protection and Engineered Safety Features Systems is such that the bistable trip setpoints do not require process transmitters to operate within 5% of the high and low end of their calibrated span or range. Functional requirements established for every channel in the Reactor Protection and Engineered Safety Features Systems stipulate the maximum allowable errors on accuracy, linearity, and reproducibility. The protection channels have the capability for, and are tested to ascertain that the characteristics throughout the entire span in all aspects are acceptable and meet functional requirement specifications. As a result, no protection channel actuates within 5% of the limits of its specified span (activation setpoints are located between 5 – 95% of span). 00-01

In this regard, it should be noted that the specific functional requirements for response time, setpoint, and operating span was finalized based on the results and evaluation of safety studies carried out using data pertinent to the plant. Emphasis is placed on establishing adequate performance requirements under both normal and faulted conditions. This includes consideration of process transmitters margins such that even under a highly improbable situation of full power operation at the limits of the operating map (as defined by the high and low pressure reactor trip, ΔT overpower and

overtemperature trip lines (departure from nucleate boiling protection) and the steam generator safety valve pressure setpoint) that adequate instrument response is available to ensure plant safety.

7.1.2.1.10 Engineered Safety Features Motor Specifications

Engineered safety features motor specifications are described in Section 8.3.1.1.4.

7.1.2.2 Independence of Redundant Safety-Related Systems

The safety related systems in Section 7.1.1.1 are designed to meet the independence and separation requirements of Criterion 22 of the 1971 General Design Criteria and paragraph 4.6 of IEEE Standard 279-1971.

The electrical power supply, instrumentation, and control conductors for redundant circuits of a nuclear plant have physical separation to preserve the redundancy and to ensure that no single credible event will prevent operation of the associated function due to electrical conductor damage. Critical circuits and functions include power, control and analog instrumentation associated with the operation of the Reactor Trip System or Engineered Safety Features Actuation System. Credible events shall include, but not be limited to, the effects of short circuits, pipe rupture, missiles, fire, etc., and are considered in the basic plant design.

7.1.2.2.1 General

Specifications for field wiring of redundant circuitry are discussed in Section 8.3.1.4.

The physical separation criteria for redundant safety related system sensors, sensing lines, wireways, cables, and components on control boards/racks within Westinghouse scope meet recommendations contained in Regulatory Guide 1.75 and Westinghouse letter NS-CE-604 of March 31, 1975 from C. Eicheldinger to the Secretary of the Commission.

7.1.2.2.2 Specific Systems

Independence is maintained throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs and Reactor Building penetrations for each redundant protection channel set. Redundant analog equipment is separated by locating modules in different protection rack sets. Each redundant channel set is energized from a separate a-c power feed.

There are 4 separate process analog sets. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, Reactor Building penetrations, and analog protection cabinets to the redundant trains in the logic racks. Redundant analog channels are separated by locating modules in different cabinets.

Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet.

In the Nuclear Instrumentation System, Process Systems, and Solid-State Protection System input cabinets where redundant channel instrumentation are physically adjacent, there are no wireways, or cable penetrations which would permit, for example, a fire resulting from electrical failure in one channel to propagate into redundant channels in the logic racks. Redundant analog channels are separated by locating modules in different cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet. Nevertheless, concerns relative to wiring of isolation devices within protection cabinets prompted Westinghouse programs aimed at alleviating them. A discussion is given in Section 7.2.2.2.3.7.

Two (2) reactor trip breakers are actuated by 2 separate logic matrices which interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all full length control rod drive mechanisms, permitting the rods to free fall into the core.

1. Reactor Trip System

    a. Separate routing shall be maintained for the 4 basic Reactor Trip System channel sets analog sensing signals, bistable output signals and power supplies for such systems. The separation of these 4 channel sets shall be maintained from sensors to instrument cabinets to logic system input cabinets.

    b. Separate routing of the redundant reactor trip signals from the redundant logic system cabinets shall be maintained, and in addition, they shall be separated by spatial separation or by provision of barriers or by separate cable trays or wireways from the 4 analog channel sets.

2. Engineered Safety Features Actuation System

    a. Separate routing shall be maintained for the 4 basic sets of Engineered Safety Features Actuation System analog sensing signals, bistable output signals and power supplies for such systems. The separation of these 4 channel sets shall be maintained from sensors to instrument cabinets to logic system input cabinets.

    b. Separate routing of the engineered safety features actuation signals from the redundant logic system cabinets shall be maintained. In addition, they shall be separated by spatial separation or by provisions of barriers or by separate cable trays or wireways from the 4 analog channel sets.

c. Separate routing of control and power circuits associated with the operation of engineered safety features equipment is required to retain redundancies provided in the system design and power supplies.

3. Instrumentation and Control Power Supply System

The separation criteria presented also apply to the power supplies for the load centers and buses distributing power to redundant components and to the control of these power supplies.

4. Control Board

A majority of the control board switches and associated lights are furnished in modules. These modules provide a high degree of physical protection for the switches, associated lights, and wiring. Control board switches and associated lights which are not located in modules and other devices within the control boards are located such that a minimum of 6 inches air separation is maintained between devices and wiring associated with different trains. Where this 6 inches of air space in all directions cannot be maintained, barriers are provided or an analysis of the installation is performed. This analysis is based on tests performed to determine the flame retardant characteristics of the wiring material, equipment, and other materials internal to the panel.

Where necessary to maintain separation, cabling from devices on the front of the control board to the horizontal metal wireways (gutters) within the control board is routed in flexible conduit or metallic braid. The redundant cables are then routed through separate gutters to the termination cabinets located beneath the control room via vertical metal wireways (risers). The termination cabinets are arranged to maintain the separated routing of the control board cables through the termination cabinets to the field wiring tray systems. In addition, separate metal wireways and termination cabinets are used for the various low-level analog channels and for the various control-level channels.

Relay subpanels located in or associated with the control boards contain Class 1E devices such as fuses, relays, and relay type isolation devices. Mutually redundant safety related devices are located on separate subpanels. Separate metal wireways provide separation for Class 1E wiring and non-Class 1E wiring departing the subpanels. Where relay panels contain relay type isolation devices, the separation of the wiring from the input and output terminals to the separate wireways may be less than 6 inches provided it is not less than the 1 inch distance between input and output terminals of the isolation device.

Flame resistant cable is used for internal module wiring and multi-conductor cables within the control board. Flame resistant single conductor cable with 30 MIL insulation is used for intraboard jumpers. Sizing of copper conductors is based

upon conservative current carrying capacities set forth by the National Electric Code.

Inherent flame-retardant characteristics and properties were an important consideration in the selection, design, and fabrication of components and materials used in the control board; therefore, a postulated fire cannot propagate.

In order to maintain separation between wiring associated with different trains, mutually redundant safety train wiring is not terminated on a single device. Backup manual actuation switches link the separate trains by mechanical means to provide greater reliability of operator action for the manual reactor trip function and manual engineered safety features actuations. The linked switches are themselves redundant so that operation of either set of linked switches will actuate safety trains "A" and "B" simultaneously. This is shown in Figure 7.2-3. The design of the manual reactor trip function and manual engineered safety features actuations comply with Regulatory Guide 1.62 (see also Section 7.3.2.2.7).

Manual actuation from the control room of each Reactor Protection or Engineered Safety Features System is provided by 2 functionally redundant, physically separate and independent switches meeting the requirements of IEEE-279-1971. 99-01
In order to prevent inadvertent manual actuation of reactor building spray, a pair of switches must be operated simultaneously. A second pair of switches is provided for manual actuation so a single failure will not prevent manual actuation of the reactor building spray. Redundant switches are provided for the manual control of steam line isolation.

Control switches are provided on the control board for all components that are actuated by manual engineered safety features function initiation switches.

Manual controls for the reactor protection and engineered safety features are listed in Tables 7.2-1, 7.3-1, and 7.3-2.

Transmitted signals (flow, pressure, temperature, etc.) which cause actuation of the engineered safety features are either indicated or recorded. Redundant channels of post accident monitoring indicators are separated by barriers and/or air separation.

7.1.2.2.3 Fire Protection

Electrical equipment is supplied with noncombustible or fire retardant material. Materials which may ignite or explode from an electrical spark, flame, or from heating are not used. Current carrying capacities of instrument cabinet wiring preclude electrical fires resulting from excessive overcurrent (I^2R) losses. For example, wiring used for instrument cabinet construction has teflon or tefzel insulation and is adequately sized based on current carrying capacities set forth by the National Electric Code. In addition, fire retardant (intumescent) paint is used to prevent fire or heat propagation

from rack to rack. The application of paint to interiors and/or exteriors of nuclear safety related electrical equipment located outside the Reactor Building containment is a non-nuclear safety related activity. Braided sheathed material is noncombustible.

For early warning and protection against propagation of electrical fires, smoke or other high sensitivity detectors are provided for fire detection, alarm and extinguishing systems in remote wireways or other unattended areas where large concentrations of cables are installed (see Section 8.3.3.2).

Details of the fire protection system are provided in Section 9.5.1.

7.1.2.3 Physical Identification of Safety-Related Equipment

There are 4 separate protection sets identifiable with process equipment associated with the Reactor Trip and Engineered Safety Features Actuation Systems. A protection set may be comprised of more than a single process equipment cabinet. The color coding of each process equipment rack nameplate coincides with the color code established for the protection set of which it is a part. Redundant channels are separated by locating them in different equipment cabinets. Separation of redundant channels begins at the process sensors and is maintained in the field wiring, Reactor Building penetrations and equipment cabinets to the redundant trains in the logic racks. The Solid-State Protection System input cabinets are divided into 4 isolated compartments, each service 1 of the 4 redundant input channels. Horizontal 1/8 inch thick solid steel barriers, coated with fire retardant paint, separate the compartments. Four (4), 1/8 inch thick solid steel, wireways coated with fire retardant paint enter the input cabinets vertically, even in its own quadrant. The wireway for a particular compartment is open only into that compartment so that flame could not propagate to affect other channels. At the logic racks the protection set color coding for redundant channels is clearly maintained until the channel loses its identity in the redundant logic trains. The color coded nameplates described below provide identification of equipment associated with protective functions and their channel set association:

PROTECTION SET	COLOR CODING
I	RED with BLACK lettering
II	ORANGE with BLACK lettering
III	BLUE with BLACK lettering
IV	YELLOW with BLACK lettering

Noncabinet mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components such as relays have nameplates on the enclosure which houses them. There are also identification nameplates on the input panels of the Solid-State Logic Protection System. The identification of cables, cable trays, conduits and electrical equipment is discussed in Section 8.3.1.5. 99-01

7.1.2.4 Conformance to Criteria

A listing of applicable criteria and the sections where conformance is discussed is given in Tables 7.1-1 and 7.1-2.

7.1.2.5 Conformance to Regulatory Guide 1.22

Periodic testing of the Reactor Trip and Engineered Safety Features Actuation Systems, as described in Sections 7.2.2 and 7.3.2, complies with Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions."

Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation, each bypass condition is automatically indicated to the reactor operator in the Main Control Room by a separate annunciator for the train in test. Test circuitry does not allow 2 trains to be tested at the same time so that extension of the bypass condition to the redundant system is prevented.

The actuation logic for the Reactor Trip and Engineered Safety Features Actuation System is tested as described in Sections 7.2 and 7.3. As recommended by Regulatory Guide 1.22, where actuated equipment is not tested during reactor operation it has been determined that:

1. There is no practicable system design that would permit operation of the equipment without adversely affecting the safety or operability of the plant;

2. The probability that the protection system will fail to initiate the operation of the equipment is, and can be maintained, acceptably low without testing the equipment during reactor operation; and

3. The equipment can routinely be tested when the reactor is shutdown.

The list of equipment that cannot be tested at full power so as not to damage equipment or upset plant operation is:

1. Manual actuation switches.

2. Reactor coolant pump breakers.

3. Turbine.

4. Main steam line isolation valves (complete closure).

5. Main feedwater isolation valves (close).

6. Feedwater control valves and feedwater bypass control valves (close).

7. Main feedwater pump trip solenoids.

8. Reactor coolant pump component cooling water isolation valves (close).

9. Reactor coolant pump seal water return valves (close).

10. Instrument air supply to reactor building isolation valves (close).

11. Engineered safety features loading sequencer input buffer and output relays.

The justifications for not testing the above items at full power are discussed below:

1. Manual Actuation Switches

   These would cause initiation of their protection system function at power causing plant upset and/or reactor trip. The analog signals, from which the automatic safety injection signal is derived, is tested at power in the same manner as the other analog signals and as described in Section 7.2.2.2.3. The processing of these signals in the Solid-State Protection System wherein their channel orientation converts to a logic train orientation is tested at power by the built-in semiautomatic test provisions of the Solid-State Protection System. The reactor trip breakers are tested at power as discussed in Section 7.2.2.2.3.

2. Reactor Coolant Pump Breakers

   No credit is taken in the accident analyses for a reactor coolant pump breaker opening causing a reactor trip. Since testing them at power would cause plant upset, the reactor coolant pump breakers do not need to be tested at power.

3. Turbine

   Testing of the main turbine trip signals during normal operation would result in a reactor trip. Although the Turbine Trip System is not qualified as a safety related system, it is a highly reliable system. The details of the Turbine Trip System, including types of tests and frequency of tests of components vital to successful tripping of the turbine are discussed in the "Turbine Missile Report" referenced in Section 10.2.

   The interface between the Engineered Safety Features System and the Turbine Trip System is shown functionally on Figure 7.2-1, Sheet 15. The "B" train trip signal energizes a 125 volt d-c "B" train relay at the turbine electrohydraulic controls control cabinet which, in turn, energizes redundant relays on the electrohydraulic controls 24 volt trip system. One (1) of the 24 volt relays de-energizes the master trip solenoids which trips the turbine by dumping the electrohydraulic controls emergency trip fluid, while the redundant relay energizes

the 125 volt d-c mechanical trip solenoid to dump the electrohydraulic controls emergency trip fluid. The redundant "A" train trip signal trips the turbine in parallel with other 125 volt d-c non-train trip signals via an isolating relay and a separate 125 volt d-c relay at the electrohydraulic controls control panel. This non-train relay energizes the same 24 volt d-c tripping relays as the "B" train relay. It should be noted that failure of the 24 volt d-c electrohydraulic controls power supply will trip the turbine by de-energizing the master trip solenoids.

Based on the identified problem incurred with periodic testing of turbine trip at power and since: 1) no practical system design will permit operation of turbine trip without affecting the safety or operability of the plant, 2) the probability that the protection system will fail to trip the turbine is acceptably low due to the redundancy and power fail safe features in the trip system and 3) the complete turbine trip system will be routinely tested during refueling outages, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22 (see Appendix 3A).

4. Main Steam Line Isolation Valves (Complete Closure)

Main steam line isolation valves are routinely tested during refueling outages. Testing of the main steam line isolation valves to full closure at power is not practical. As the plant power is increased, the core average temperature is programmed to increase. If the valves are fully closed under these elevated temperature conditions, the steam pressure transient would unnecessarily operate the steam generator relief valves and possibly the steam generator safety valves. The steam pressure transient produced would cause shrinkage in the steam generator level, which would cause the reactor to trip on low-low steam generator water level. Testing during operation will decrease the operating life of the valve.

Based on the above identified problems incurred with periodic testing of the main steam line isolation valves at power and since, 1) no practical system design will permit operation of the valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the actuated equipment is acceptably low due to test up to final actuation, 3) these valves will be routinely tested during refueling outages, and 4) these valves are tested during plant operation by partial closure (90 to 95 percent open) by actuating a test solenoid valve which does not inhibit an engineered safety feature automatic closure, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

5. Main Feedwater Isolation Valves (Close)

The main feedwater isolation valves are routinely tested during refueling outages. Periodic testing of these feedwater isolation valves, closing them completely, or partially, at power would induce steam generator water level transients and oscillations which would trip the reactor. These transient conditions would be caused by perturbing the feedwater flow and pressure conditions necessary for proper operation of the variable-speed feedwater pump control system and the steam generator water level control system. An operation which induces perturbations in the main feedwater flow, whether deliberate or otherwise, may lead to a reactor trip and should be avoided.

Based on these identified problems incurred with periodic testing of the backup feedwater valves at power and since, 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the activated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

6. Feedwater Control Valves (Close)

These valves are routinely tested during refueling outages. To close them at power would adversely affect the operability of the plant. The verification of operability of feedwater control valves at power is assured by confirmation of proper operation of the Steam Generator Water Level System. The actual actuation function of the solenoids, which provides the closing function is periodically tested at power as discussed in Section 7.3.2.2.5. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the actual closing of these control valves is blocked when the slave relay is tested, all functions are tested to assure that no electrical malfunctions have occurred which could defeat the protective function. It is noted that the solenoids work on the de-energize-to-actuate principle, so that the feedwater control valves will fail close upon either the loss of electrical power to the solenoids or loss of air pressure.

Based on the above, the testing of the isolating function of feedwater control valves meets the guidelines of Section D.4 of Regulatory Guide 1.22.

7. Main Feedwater Pump Trip Solenoids

The containment integrity analysis assumes the feedwater isolation valves and/or feedwater control valves isolate feedwater flow and therefore the feedwater pump trip solenoids require no periodic testing.

However, these trip solenoids are routinely tested during refueling outages. To close them at full power would adversely affect the operability of the plant. The actual actuation function of the solenoids, which provides the closing function is periodically tested at power as discussed in Section 7.3.2.2.5. The operability of the slave relay which actuates the solenoid, which is the actuating device, is verified during this test. Although the actual closing of these trip solenoids is blocked when the slave relay is tested, all functions are tested to assure that no electrical malfunctions have occurred which could defeat the function of the solenoids.

8. Reactor Coolant Pump Component Cooling Water Isolation

   Valves (Close)

   Component cooling water supply and return containment isolation valves are routinely tested during refueling outages. Testing of these valves while the reactor coolant pumps are operating introduces an unnecessary risk of costly damage to all the reactor coolant pumps. Loss of component cooling water to these pumps is of economic consideration only, as the reactor coolant pumps are not required to perform any safety-related function.

   The reactor coolant pumps will not seize due to complete loss of component cooling. Information from the pump manufacturer indicates that the bearing babbitt would eventually break down but not so rapidly as to overcome the inertia of the flywheel. If the pumps are not stopped within 3 to 10 minutes after component cooling water is isolated, pump damage could be incurred.

   Also, since the component cooling water flowrates and temperatures are about equal during both plant power operation and plant refueling, periodic tests of these valves during a refueling outage would duplicate accident conditions. Additionally, possibility of failure of containment isolation is remote because an additional failure of the low pressure fluid system in addition to failure of both isolation valves would have to occur to open a path through the containment.

   Based on the above described potential reactor coolant pump damage incurred with periodic testing of the component cooling water containment isolation valves at power, the duplication of at-power operating conditions during refueling outages, and since, 1) no practical system design will permit operation of these valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the activated equipment is acceptably low due to testing up to final actuation, and 3) these valves will be routinely tested during refueling outages when the reactor coolant pumps are not operating, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

9. Reactor Coolant Pump Seal Water Return Valves (Close)

Seal return line isolation valves are routinely tested during refueling outages. Closure of these valves during operation would cause the safety valve to lift, with the possibility of valve chatter. Valve chatter would damage this relief valve. Testing of these valves at power would cause equipment damage. Therefore, these valves will be tested during scheduled refueling outages. As above, additional containment penetrations and isolation valves introduce additional unnecessary potential pathways for radioactive release following a postulated accident. Thus, the guidelines of Section D.4 of Regulatory Guide 1.22 are met.

10. Instrument Air Supply to Reactor Building Isolation

Valves (Close)

The Reactor Building instrument air isolation valves are routinely tested during refueling outages. Closing the valves completely at power would result in loss of instrument air supply inside containment, causing an upset to normal operation which could cause a reactor trip.

Based on the above identified problem incurred with periodic testing of the Reactor Building instrument air isolation valves at power and since, 1) no practical system design will permit operation of the valves without adversely affecting the safety or operability of the plant, 2) the probability that the protection system will fail to initiate the actuated equipment is acceptably low due to test up to final actuation, and 3) these valves will be routinely tested during refueling outages, the proposed resolution meets the guidelines of Section D.4 of Regulatory Guide 1.22.

11. Engineered Safety Feature Loading Sequencer Input Buffer and Output Relays

The Engineered Safety Feature Loading Sequencer output and input buffer relays are routinely tested during refueling outages. Testing the output relays will actuate plant equipment and requires extensive system and breaker alignments to perform the entire output relay test. Due to the intensity required for testing, plant operability and safety could be jeopardized. The Engineered Safety Feature Loading Sequencer is not designed to test the output relays by continuity of the electrical circuitry associated with the relays as a check in lieu of actual operation; therefore, the only test is by actuation. A reliability study showed that the probability of the output relays to fail when required to initiate the operation of equipment is, and can be, maintained acceptably low without periodic testing of the actuated equipment during reactor operation. The 18 month test frequency is acceptable. The Engineered Safety Feature Loading Sequencer is not designed to test the input buffer relays on line without actually initiating Safety Injection or Blackout sequence. The total testing by actuation of undervoltage relays and

Safety Injection signals to final equipment actuation is performed every 18 months while plant is shutdown. The inputs and logic up through the output relay drivers are tested with the reactor operational is a continuous automatic test mode.

Based on the above, the testing of the ESFLS meets the guidelines of Section D.4 of Regulatory Guide 1.22.

7.1.2.6 Conformance to Regulatory Guide 1.47

The principles described in Regulatory Guide 1.47 have been used to design the bypassed and inoperable status indication for the Engineered Safety Features Systems. System level indication is provided on the Control Room bypass and inoperable status indication CRT to display the operable status of each of the redundant portions of the Emergency Core Cooling System, the Reactor Building Cooling System, and the Reactor Building Spray System, and supporting systems: Engineered Safety Features Power System, Chilled Water System, Service Water System and Component Cooling Water System.

Inoperable indication occurs automatically when equipment vital to the operation of the system has been removed from service and a contact is available from the equipment to signify this condition (e.g., control switch in the "pull to lock" position, switchgear circuit breaker withdrawn from the operating position, safety system bypassed for logic testing). Inoperable indication also occurs when the operator, by administrative procedures, removes essential equipment from service and at the same time manually inputs the status into the Technical Support Center Computer. When automatic equipment inoperable indication occurs, it will be accompanied by an audible alarm.

The following criteria are utilized in providing contacts for automatic indication of inoperable status.

1. The bypass or inoperable condition effects one of the Emergency Core Cooling Systems, Reactor Building Cooling Systems, or Reactor Building Spray Systems, and/or the Auxiliary Support Systems for these systems are required to perform automatically a function important to the safety of the public.

2. The bypass or inoperable condition can reasonably be expected to occur more frequently than once per year.

3. The bypass or inoperable condition is expected to occur when the effected safety system is required to be operable.

7.1.2.7 Conformance to Regulatory Guide 1.53 and IEEE Standard 379-1972

The principles described in IEEE Standard 379-1972 were used in the design of the Westinghouse protection system. The system complies with the intent of this standard and the additional guidance of Regulatory Guide 1.53, although the formal analyses have not been documented exactly as outlined. Westinghouse has gone beyond the required analyses and has performed a fault tree analysis, Reference [3].

The referenced topical report provides details of the analyses of the protection systems previously made to show conformance with the single failure criterion set forth in paragraph 4.2 of IEEE Standard 279-1971. The interpretation of the single failure criterion provided by IEEE Standard 379-1972 does not indicate substantial differences with the Westinghouse interpretation of the criterion except in the methods used to confirm design reliability. Established design criteria in conjunction with sound engineering practices form the bases for the Westinghouse protection systems. The Reactor Trip and Engineered Safety Features Actuation Systems are each redundant safety systems. The required periodic testing of these systems will disclose any failures or loss of redundancy which could have occurred in the interval between tests, thus ensuring the availability of these systems.

Chapters 6.0, 8.0, 9.0, and 10.0 discuss the single failure criteria for safety systems and auxiliary support systems within the balance of plant scope. Section 7.3.2.2 outlines the degree of conformance for the Engineered Safety Features loading sequence control panels. The degree of conformance for the undervoltage/underfrequency relay panels is addressed in Section 8.3.1.1.1.

Table 7.1-3 outlines, in detail, how the specific principles described by Regulatory Guide 1.53 and IEEE 379-1972, have been used in the design of balance of plant safety related instrumentation and control systems.

7.1.2.8 Conformance to Regulatory Guide 1.63

Regulatory Guide 1.63 is discussed in Appendix 3A.

7.1.2.9 Conformance to IEEE Standard 317-1972

Electrical penetrations are designed and fabricated in accordance with the requirements of IEEE Standard 317-1972.

7.1.2.10 Conformance to IEEE Standard 336-1971

Conformance with the scope of IEEE Standard 336-1971 for installation, inspection, and testing of instrumentation and electrical equipment during construction and startup is covered in Chapters 14 and 17.

7.1.2.11 Conformance to IEEE Standard 338-1971

The periodic testing of the Reactor Trip System and Engineered Safety Features Actuation System conforms to the requirements of IEEE Standard 338-1971 with the following comments:

1. The surveillance requirements of the Technical Specifications for the protection system ensure that the system functional operability is maintained comparable to the original design standards. Periodic tests at frequent intervals demonstrate this capability for the system, excluding sensors.

   Overall protection systems response times shall be demonstrated by test. Sensors within Westinghouse scope will be demonstrated adequate for this design by vendor testing, in-site tests in operating plants with appropriately similar design, or by suitable type testing. The Nuclear Instrumentation System detectors are excluded since they exhibit response time characteristics such that delays attributable to them are negligible in the overall channel response time required for safety.

   A periodic verification test program for sensors within Westinghouse scope, for determining any deterioration of installed sensor's response time, is currently being performed by on-site Surveillance Test Procedures (STP). Should sensor fail criteria outlined in the STP, the sensor is either replaced or repaired.

   Each test shall include at least 1 logic train such that both logic trains are tested at least 1 per 36 months and 1 channel per function such that all channels are tested at least once every (N times 18 months), where N is the total number of redundant channels in a specific protective function.

   The measurement of response time at the specified time intervals provides assurance that the protective and engineered safety features action function associated with each channel is completed within the time limit assumed in the accident analyses.

2. Surveillance test failures are trended and evaluated through various programs to ensure equipment reliability specified in the IEEE Standard 338-1971.

3. The periodic time interval discussed in paragraph 4.3 of IEEE Standard 338-1971, and specified in the Technical Specifications, is conservatively selected to assure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. If any protection channel appears to be marginal or requires more frequent adjustments due to plant condition changes, the time interval will be decreased to accommodate the situation until the marginal performance is resolved.

4. The test interval discussed in paragraph 5.2 of IEEE Standard 338-1971, is developed primarily on past operating experience and modified if necessary to assure that system and subsystem protection is reliably provided. Analytic methods for determining reliability are not used to determine test interval.

Based on the scope definition given in IEEE Standard 338-1971, no other systems described in Chapter 7 are required to comply with this standard.

7.1.3 REFERENCES

1. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations," IEEE Standard 279-1971.

2. Katz, D. N., "Solid-State Logic Protection System Description," WCAP-7488-L (Proprietary), March, 1971 and WCAP-7672 (Non-Proprietary), May, 1971.

3. Gangloff, W. C. and Loftus, W. D., "An Evaluation of Solid-State Logic Reactor Protection in Anticipated Transients," WCAP-7706-L (Proprietary) and WCAP-7706 (Non-Proprietary), February, 1973.

TABLE 7.1-1

LISTING OF APPLICABLE CRITERIA

	CRITERIA	TITLE	CONFORMANCE DISCUSSED IN	
1.	General Design Criteria (GDC), Appendix A to 10 CFR 50			
	GDC-1	Quality Standards and Records	3.1.2, 7	
	GDC-2	Design Bases for Protection Against Natural Phenomena	3.1.2, 3.10, 7.2.1.11	
	GDC-3	Fire Protection	3.1.2, 7.1.2.2.3	
	GDC-4	Environmental and Missile Design Bases	3.1.2, 7.2.2.2	
	GDC-5	Sharing of Structures, Systems, and Components	3.1.2	
	GDC-10	Reactor Design	3.1.2, 7.2.2.2	
	GDC-12	Suppression of Reactor Power Oscillations	3.1.2	
	GDC-13	Instrumentation and Control	3.1.2, 7.3.1, 7.3.2	
	GDC-15	Reactor Coolant System Design	3.1.2, 7.2.2.2	
	GDC-17	Electric Power Systems	3.1.2, Chapter 8	00-01
	GDC-19	Control Room	3.1.2	

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

CRITERIA	TITLE	CONFORMANCE DISCUSSED IN
GDC-20	Protection System Functions	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-21	Protection System Reliability and Testability	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-22	Protection System Independence	3.1.2, 7.1.2.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-23	Protection System Failure Modes	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-24	Separation of Protection and Control Systems	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
GDC-25	Protection System Requirements for Reactivity Control Malfunctions	3.1.2, 7.3.2
GDC-26	Reactivity Control System Redundancy and Capability	3.1.2
GDC-27	Combined Reactivity Control Systems Capability	3.1.2, 7.3.1, 7.3.2
GDC-28	Reactivity Limits	3.1.2, 7.3.1, 7.3.2
GDC-29	Protection Against Anticipated Operational Occurrences	3.1.2, 7.2.2.2
GDC-33	Reactor Coolant Makeup	3.1.2
GDC-34	Residual Heat Removal	3.1.2
GDC-35	Emergency Core Cooling	3.1.2, 7.3.1, 7.3.2
GDC-37	Testing of Emergency Core Cooling System	3.1.2, 7.3.2
GDC-38	Containment Heat Removal	3.1.2, 7.3.1, 7.3.2

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

CRITERIA	TITLE	CONFORMANCE DISCUSSED IN	
GDC-40	Testing of Containment Heat Removal System	3.1.2, 7.3.2	
GDC-41	Containment Atmosphere Cleanup	3.1.2	00-01
GDC-43	Testing of Containment Atmosphere Cleanup Systems	3.1.2, 7.3.2	
GDC-44	Cooling Water	3.1.2	
GDC-46	Testing of Cooling Water System	3.1.2, 7.3.2	
GDC-50	Containment Design Basis	3.1.2	
GDC-54	Piping Systems Penetrating Containment	3.1.2	
GDC-55	Reactor Coolant Pressure Boundary Penetrating Containment	3.1.2	
GDC-56	Primary Containment Isolation	3.1.2	
GDC-57	Closed Systems Isolation Valves	3.1.2	

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

	CRITERIA	TITLE	CONFORMANCE DISCUSSED IN
2.	Institute of Electrical and Electronics Engineers (IEEE) Standards:		
	IEEE Std 279-1971 (ANSI N42.7-1972)	Criteria for Protection Systems for Nuclear Power Generating Stations	7.1, 7.2, 7.3, 7.6
	IEEE Std 308-1971	Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations	7.6
	IEEE Std 317-1972	Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations	7.1.2.9
	IEEE Std 323-1971	IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations	3.11
	IEEE Std 334-1971	Type Tests of Continuous-Duty Class 1 Motors Installed Inside the Containment of Nuclear Power Generating Stations	3A (RG 1.40)
	IEEE Std 336-1971 (ANSI N45.2.4-1972)	Installation, Inspection and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations	7.1.2.10
	IEEE Std 338-1971	Criteria for the Periodic Testing of Nuclear Power Generation Station Protection Systems	7.1.2.11

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

CRITERIA	TITLE	CONFORMANCE DISCUSSED IN
IEEE Std 344-1971 (ANSI N41.7)	Guide for Seismic Qualification of Class 1 Electrical Equipment for Nuclear Power Generating Stations	3.10
IEEE Std 379-1972 (ANSI N41.2)	Guide for the Application of the Single Failure Criterion to Nuclear Power Generating Station Protection Systems	7.1.2.7
IEEE Std 382-1972	Type Test of Class 1 Electric Valve Operators	3.11
IEEE Std 384-1974 (ANSI N41.14)	Criteria for Separation of Class 1E Equipment and Circuits	7.1.2.2.1

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

	CRITERIA	TITLE	CONFORMANCE DISCUSSED IN
3.	Regulatory Guides (RG)		
	RG 1.6	Independence Between Redundant Stand-by Onsite) Power Sources and Between Their Distribution Systems	Chapter 8
	RG 1.11	Instrument Lines Penetrating Primary Reactor Containment	3A, 7.3.1.1.2
	RG 1.22	Periodic Testing of Protection System Actuation Functions	3A, 7.1.2.5, 7.3.2.2.5
	RG 1.29	Seismic Design Classification	3A
	RG 1.30	Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electric Equipment	3A, Chapter 17
	RG 1.32	Use of IEEE Std 308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Station"	7.6
	RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems	3A, 7.1.2.6
	RG 1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems	3A, 7.1.2.7
	RG 1.62	Manual Initiation of Protection Actions	3A, 7.3.2.2.7
	RG 1.63	Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants	3A

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

CRITERIA	TITLE	CONFORMANCE DISCUSSED IN	
RG 1.68	Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors	3A, Chapter 14	
RG 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, Rev. 2	3A, Chapter 7	
RG 1.73	Qualification Test of Electric Valve Operators Installed Inside the Containment of Nuclear Power Plants	3A	00-01
RG 1.75	Physical Independence of Electric Systems	3A, 7.1.2.2.1	
RG 1.80	Preoperational Testing of Instrument Air Systems	3A, 9.3.1	
RG 1.89	Qualification of Class 1E Equipment for Nuclear Power Plants	3A, 3.11	
RG 1.95	Protection of Nuclear Power Plant Control Room Operators Against An Accident Chlorine Release	3A, 6.4	00-01
RG 1.97	Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident	3A	
RG 1.100	Seismic Qualification of Electric Equipment for Nuclear Power Plants	3A	
RG 1.105	Instrument Spans and Setpoints	3A	
RG 1.106	Thermal Overload Protection for Electric Motors on Motor-Operated Valves		
RG 1.114	Guidance on Being Operator at the Controls of a Nuclear Power Plant	3A	

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

	CRITERIA	TITLE	CONFORMANCE DISCUSSED IN	
4.	Branch Technical Positions (BTP) EICSB			
	BTP EICSB 1	Backfitting of the Protection and Emergency Power Systems of Nuclear Reactors	Chapters 7, 8	
	BTP EICSB 3	Isolation of Low Pressure Systems from the High Pressure Reactor Coolant System	7.6.2	
	BTP EICSB 4	Requirements on Motor Operated Valves in the ECCS Accumulator Lines	7.6.4	
	BTP EICSB 5	Scram Breaker Test Requirements - Technical Specifications	7.2.2.2.3, Technical Specifications (Table 4.3-1, Item 21)	00-01
	BTP EICSB 9	Definition and Use of "Channel - Calibration" - Technical Specifications	Technical Specifications (Table 4.3-1, Item 2)	
	BTP EICSB 10	Electrical and Mechanical Equipment Seismic Qualification Program	3.10	

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

CRITERIA	TITLE	CONFORMANCE DISCUSSED IN	
BTP EICSB 12	Protection System Trip Point Changes for Operation with Reactor Coolant Pumps Out of Service	7.2.2.2.1, Technical Specifications (3/4.1)	00-01
BTP EICSB 13	Design Criteria for Auxiliary Feedwater Systems	7.3.2.3	
BTP EICSB 14	Spurious Withdrawals of Single Control Rods in Pressurized Water Reactors	7.7.2.2, 15.2.1, 15.2.2, 15.3.6	
BTP EICSB 15	Reactor Coolant Pump Breaker Qualification	3.10, 7.1.2.5, 7.2.1.1.2(4)	
BTP EICSB 16	Control Element Assembly (CEA) Interlocks in Combustion Engineering Reactors	Not Applicable	
BTP EICSB 18	Application of the Single Failure Criteria to Manually Controlled Electrically Operated Valves	Technical Specifications (3/4.5)	00-01
BTP EICSB 19	Acceptability of Design Criteria for Hydrogen Mixing and Drywell Vacuum Relief Systems	Not Applicable	
BTP EICSB 20	Design of Instrumentation and Controls Provided to Accomplish Changeover from Injection to Recirculation Mode	7.6.5, 6.3.2.2.2, Table 6.3-3	

TABLE 7.1-1 (Continued)

LISTING OF APPLICABLE CRITERIA

CRITERIA	TITLE	CONFORMANCE DISCUSSED IN
BTP EICSB 21	Guidance for Application of Reg. Guide 1.47	7.1.2.6
BTP EICSB 22	Guidance for Application of Reg. Guide 1.22	7.1.2.5
BTP EICSB 23	Qualification of Safety-Related Display Instrumentation for Post Accident Condition Monitoring and Safe Shutdown	7.5
BTP EICSB 24	Testing of Reactor Trip System and Engineered Safety Feature Actuation System Sensor Response Times	7.1.2.11
BTP EICSB 25	Guidance for the Interpretation of General Design Criterion 37 for Testing the Operability of the Emergency Core Cooling System as a Whole	3.1.2
BTP EICSB 26	Requirements for Reactor Protection System Anticipatory Trips	7.2.1.1.2
BTP EICSB 27	Design Criteria for Thermal Overload Protection for Motors of Motor Operated Valves	8.3.1.3

TABLE 7.1-2

APPLICABLE CRITERIA

		REACTOR TRIP SYSTEM (RTS) 7.2			ENGINEERED SAFETY FEATURES SYSTEM (ESF) 7.3										ENGINEERED SAFETY FEATURES SUPPORTING SYSTEMS (ESF SUPPORTING)					SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4							SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4				SAFETY RELATED DISPLAY INSTRUMENTS (SR) 7.5				ALL OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY 7.6					CONTROL SYSTEMS NOT REQUIRED FOR SAFETY 7.7 (1)
		NSSS INPUTS	RCP INPUTS	TURBINE INPUTS (2)	7.3 ESFAS	6.2.2 RB HEAT REMOVAL	6.2.3 RB AIR PURIFICATION AND CLEANUP	6.2.4 CONTAINMENT ISOLATION	6.2.5 COMBUSTIBLE GAS CONTROL	6.2.6 CONTAINMENT LEAKAGE TESTING (3)	6.3 SI	6.4 HABITABILITY SYSTEMS	6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS	10.4.9 EMERGENCY FEEDWATER	9.2.2 CC SYSTEM	9.5 DG SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	6.2, 9.4 HVAC SYSTEMS (4)	9.2.2 CC SYSTEM	9.5 DG SYSTEM	10.4.9 EF SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	10.3 MS SYSTEM (5)	6.2, 9.4 HVAC SYSTEMS (4)	9.3.4 CHARGING PUMPS (6)	9.3.4 BA TRANSFER PUMPS	CREP MONITORING INDICATORS W	CREP MONITORING INDICATORS BOP	PAM W	PAM BOP	ESF MONITOR LIGHTS W	ESF MONITOR LIGHTS BOP	7.6.1 I & C POWER SUPPLY SYSTEM	7.6.2 RHR INTERLOCKS	7.6.3 REFUELING INTERLOCKS	7.6.4 ACCUMULATOR MOTOR OPERATED VALVES	7.6.5 LEAK DETECTION SYSTEMS	
	GENERAL DESIGN CRITERIA																																							
GDC-1	QUALITY STANDARDS AND RECORDS	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	–	X	X	X	57	X	7	
GDC-2	DESIGN BASES FOR PROTECTION AGAINST NATURAL PHENOMENA	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	X	57	X	X	
GDC-3	FIRE PROTECTION (8)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	X	57	X	X	
GDC-4	ENVIRONMENTAL AND MISSILE DESIGN BASES	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	X	57	X	X	
GDC-5	SHARING OF STRUCTURES, SYSTEMS, AND COMPONENTS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-10	REACTOR DESIGN	X	–	–	X	–	–	–	–	–	X	–	–	X	X	–	X	–	–	X	–	X	X	–	X	–	X	X	–	X	X	X	–	X	X	X	–	X	–	
GDC-12	SUPPRESSION OF REACTOR POWER OSCILLATIONS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-13	INSTRUMENTATION AND CONTROL	X	X	X	X	X	X	X	X	–	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	X	–	X	X	X	–	X	X	
GDC-15	REACTOR COOLANT SYSTEM DESIGN	X	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-17	ELECTRIC POWER SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	X	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	
GDC-19	CONTROL ROOM	–	–	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	
GDC-20	PROTECTION SYSTEM FUNCTIONS	X	X	X	X	9	9	9	–	–	9	9	9	9	9	9	9	9	9	9	9	X	9	9	9	9	–	–	–	–	–	–	–	–	X	–	–	–	–	
GDC-21	PROTECTION SYSTEM RELIABILITY AND TESTABILITY	X	X	–	X	9	9	9	–	–	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	–	–	–	–	10	10	–	–	X	X 11	–	–	–	
GDC-22	PROTECTION SYSTEM INDEPENDENCE	X	X	X	X	9	9	9	–	–	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	–	–	–	–	12	12	–	–	X	–	–	–	–	
GDC 23	PROTECTION SYSTEM FAILURE MODES	X	X	13	13	9	9	9	–	–	13	9	9	9	9	13	9	9	9	9	13	9	9	9	9	9	–	–	–	–	–	–	–	–	13	–	–	–	–	
GDC-24	SEPARATION OF PROTECTION AND CONTROL SYSTEMS	X	X	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	X	–	X	–	–	–	–	X	
GDC-25	PROTECTION SYSTEM REQUIREMENTS FOR REACTIVITY CONTROL MALFUNCTIONS	14	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-26	REACTIVITY CONTROL SYSTEM REDUNDANCY AND CAPABILITY	15	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	15	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-27	COMBINED REACTIVITY CONTROL SYSTEMS CAPABILITY	16	–	–	16	–	–	–	–	–	16	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-28	REACTIVITY LIMITS	17	–	–	17	–	–	–	–	–	17	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-29	PROTECTION AGAINST ANTICIPATED OPERATIONAL OCCURRENCES	X	X	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	X	X	X	X	–	–	–	X	
GDC-33	REACTOR COOLANT MAKEUP	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	X	X	X	–	X	–	X	X	–	X	X 18	X 18	–	–	–	–	–	–	X	–	–	–	–	
GDC-34	RESIDUAL HEAT REMOVAL	–	–	–	X	–	–	–	–	–	19	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X 19	X	X	–	X	X	X	–	–	X	
GDC-35	EMERGENCY CORE COOLING	–	–	–	X	–	–	–	–	–	20	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	X	X	–	X	X	–	–	X	X	
GDC-37	TESTING OF EMERGENCY CORE COOLING SYSTEM	–	–	–	X	–	–	–	–	–	20	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	–	X	
GDC-38	CONTAINMENT HEAT REMOVAL	–	–	–	X	X	X	–	–	–	–	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	–	X	
GDC-40	TESTING OF CONTAINMENT HEAT REMOVAL SYSTEM	–	–	–	X	13	13	–	–	–	–	–	–	–	X	X	X 13	X 13	X	X	X	–	X 13	X 13	–	X	–	–	–	X	–	X	–	X	X	–	–	–	X	
GDC-41	CONTAINMENT ATMOSPHERE CLEANUP	–	–	–	X	13	13	–	13	–	–	–	13	–	–	X	X 13	X 13	X	–	X	–	X 13	X 13	–	X	–	–	–	X	–	X	–	X	X	–	–	–	X	
GDC-43	TESTING OF CONTAINMENT ATMOSPHERE CLEANUP SYSTEM	–	–	–	X	X 13	X 13	–	X 13	–	–	–	X 13	–	–	X	X 13	X 13	X	–	X	–	X 13	X 13	–	X	–	–	–	X	–	X	–	X	X	–	–	–	X	
GDC-44	COOLING WATER	–	–	–	X	–	–	–	–	–	–	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	–	X	
GDC-46	TESTING OF COOLING WATER SYSTEM	–	–	–	X	–	–	–	–	–	–	–	–	–	X	X	X	X	X	X	X	–	X	X	–	X	–	–	–	X	–	X	–	X	X	–	–	–	X	
GDC-50	CONTAINMENT DESIGN BASIS	–	–	–	–	–	–	X	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-54	PIPING SYSTEMS PENETRATING CONTAINMENT	–	–	–	X 13	–	–	X 13	–	X 13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-55	REACTOR COOLANT PRESSURE BOUNDARY PENETRATING CONTAINMENT	–	–	–	13	–	–	13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-56	PRIMARY CONTAINMENT ISOLATION	–	–	–	13	–	–	13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
GDC-57	CLOSED SYSTEMS ISOLATION VALVES	–	–	–	13	–	–	13	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
	IEEE STANDARDS																																							
IEEE 279-1971	CRITERIA FOR PROTECTION SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS	X	X	X	X	21	21	21	21 22	–	21 22	21 22	21	21	21	21	21	21	21	21	21	21	21	21	21	21	–	–	–	21	23	21	–	21	X	24	–	22	21	
IEEE 396-1971	CRITERIA FOR CLASS 1R ELECTRIC SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS	–	–	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X 26	28	26	X	X	26	26	X	X	–	X	26	
IEEE 317-1972	ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR NUCLEAR POWER GENERATING STATIONS	X	–	–	X	X	X	X	X	X	X	–	X	–	X	–	X	–	X	X	–	–	X	–	–	X	–	–	X	X	X	X	X	X	–	X	–	X	X	
IEEE 323-1971	IEEE STANDARD FOR QUALIFYING CLASS 1E EQUIPMENT FOR NUCLEAR POWER GENERATING STATIONS	27	27	–	27	27	27	27	27	–	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	–	–	–	27	27	–	–	27	27	–	27	–	
IEEE 334-1971	TYPE TEST OF CONTINUOUS DUTY CLASS 1 MOTORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER GENERATING STATIONS	–	–	–	–	27 28	–	–	–	–	–	–	27 28	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
IEEE 336-1971	INSTALLATION, INSPECTION AND TESTING REQUIREMENTS FOR INSTRUMENTATION AND ELECTRIC EQUIPMENT DURING THE CONSTRUCTION OF NUCLEAR POWER GENERATING STATIONS	X	X	X	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	X	X	–	–	X	X	–	X	–	
IEEE 338-1971	CRITERIA FOR THE PERIODIC TESTING OF NUCLEAR POWER GENERATION STATION PROTECTION SYSTEMS (29)	X	X	X	X 9	9	9	9	9	X	9 30	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	–	–	–	–	X	X	–	–	9	11	–	30	–	
IEEE 344-1971	GUIDE FOR SEISMIC QUALIFICATION OF CLASS 1 ELECTRICAL EQUIPMENT FOR NUCLEAR POWER GENERATING STATIONS	31	31	–	31	31	31	31	31	–	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	–	–	31	31	31	–	–	31	31	57	31	32	
IEEE 379-1972	GUIDE FOR THE APPLICATION OF THE SINGLE FAILURE CRITERIA TO NUCLEAR POWER GENERATING STATION PROTECTION SYSTEMS	33	X	X	33	33	33	33	33 34	–	35	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	–	–	–	33	33	33	–	33	X	11	–	35	33	
IEEE 382-1972	TYPE TEST OF CLASS 1 ELECTRIC VALVE OPERATORS	–	–	–	–	27	27	27	27	–	27	27	27	27	27	–	27	27	27	27	–	27	27	27	27	27	–	–	–	–	–	–	–	–	–	27	–	27	–	
IEEE 384-1974	CRITERIA FOR SEPARATION OF CLASS 1E EQUIPMENT AND CIRCUITS	12	12	12	12	12	12	12	12	–	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	–	12 38	12	12	12	12	12	12	12	12	–	12	12	

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TABLE 7.1-2

APPLICABLE CRITERIA (Continued)

		REACTOR TRIP SYSTEM (RTS) 7.2			ENGINEERED SAFETY FEATURES SYSTEM (ESF) 7.3										ENGINEERED SAFETY FEATURES SUPPORTING SYSTEMS (ESF SUPPORTING)					SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4							SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4				SAFETY RELATED DISPLAY INSTRUMENTS (SR) 7.5				ALL OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY 7.6					CONTROL SYSTEMS NOT REQUIRED FOR SAFETY 7.7 (1)
		NSSS INPUTS	RCP INPUTS	TURBINE INPUTS (2)	7.3 ESFAS	6.2.2 RB HEAT REMOVAL	6.2.3 RB AIR PURIFICATION AND CLEANUP	6.2.4 CONTAINMENT ISOLATION	6.2.5 COMBUSTIBLE GAS CONTROL	6.2.6 CONTAINMENT LEAKAGE TESTING (3)	6.3 SI	6.4 HABITABILITY SYSTEMS	6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS	10.4.9 EMERGENCY FEEDWATER	9.2.2 CC SYSTEM	9.5 DG SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	6.2, 9.4 HVAC SYSTEMS (4)	9.2.2 CC SYSTEM	9.5 DG SYSTEM	10.4.9 EF SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	10.3 MS SYSTEM (5)	6.2, 9.4 HVAC SYSTEMS (4)	9.3.4 CHARGING PUMPS (6)	9.3.4 BA TRANSFER PUMPS	CREP MONITORING INDICATORS W	CREP MONITORING INDICATORS BOP	PAM W	PAM BOP	ESF MONITOR LIGHTS W	ESF MONITOR LIGHTS BOP	7.6.1 I & C POWER SUPPLY SYSTEM	7.6.2 RHR INTERLOCKS	7.6.3 REFUELING INTERLOCKS	7.6.4 ACCUMULATOR MOTOR OPERATED VALVES	7.6.5 LEAK DETECTION SYSTEMS	
	REGULATORY GUIDES (APPENDIX 3A DELINEATES THE APPLICABLE RG REVISION AND/OR DATE).																																							
RG 1.6	INDEPENDENCE BETWEEN REDUNDANT STANDBY (ONSITE) POWER SOURCES AND BETWEEN THEIR DISTRIBUTION SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	X	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	
RG 1.7	CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT FOLLOWING A LOSS-OF-COOLANT ACCIDENT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.11	INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT	–	–	–	38	–	–	38	X	39	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	38	–	–	–	–	–	–	–	–	
RG 1.12	INSTRUMENTATION FOR EARTHQUAKES (40)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.22	PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS	X	–	–	41	41	41	41	41	–	30 41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	–	–	–	–	10	10	–	–	–	24	–	30	–	
RG 1.29	SEISMIC DESIGN CLASSIFICATION	38	38	–	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	–	–	–	38	38	38	–	38	38	38	57	38	38	
RG 1.30	QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING OF INSTRUMENTATION AND ELECTRICAL EQUIPMENT (38)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	X	X	X	–	X	X	X	–	X	X	
RG 1.32	USE OF IEEE STANDARD 308-1971 "CRITERIA FOR CLASS 1E ELECTRIC SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS"	–	–	–	X 38	X 38	X 38	X 38	X 38	–	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 26 38	26	26 38	X	X 38	26	26 38	X 38	X	–	X 38	26 38	
RG 1.45	REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	42	
RG 1.47	BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS	–	–	–	X 43	X 43	X 43	X 43	X 43	–	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	X 43	–	–	–	–	–	–	–	X 43	–	–	–	–	
RG 1.53	APPLICATION OF THE SINGLE FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS	33	X	X	33	33	33	33	33 34	–	35	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	–	–	–	33	33	33	–	33	X	11	–	35	33	
RG 1.62	MANUAL INITIATION OF PROTECTION ACTIONS	X	–	–	X	X	X	X	X	–	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.63	ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR WATER-COOLED NUCLEAR POWER PLANTS	38	–	–	38	38	38	38	38	38	38	–	38	–	38	–	38	–	38	38	–	–	38	–	–	38	–	–	38	38	38	38	38	38	–	38	–	38	38	
RG 1.68	PREOPERATIONAL AND INITIAL START-UP TEST PROGRAMS FOR WATER-COOLED POWER REACTORS	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	–	X 38	X 38	
RG 1.70	STANDARD FORMAT AND CONTENT OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS. REV. 1 (38)	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
RG 1.73	QUALIFICATION TEST OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT	–	–	–	–	27	27	27	27	–	27	–	27	–	27	–	27	–	–	27	–	–	27	–	–	–	–	–	–	–	–	–	–	–	–	27	–	27	–	
RG 1.75	PHYSICAL INDEPENDENCE OF ELECTRIC SYSTEMS	12	12	12	12	12	12	12	12	–	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12 38	–	12	12	12	12	12	12	12	–	12	12	
RG 1.80	PREOPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS (30)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.89	QUALIFICATION OF CLASS 1E EQUIPMENT FOR NUCLEAR POWER PLANTS	27	27	–	27	27	27	27	27	–	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	–	–	–	27	27	–	–	27	27	–	27	–	
RG 1.95	PROTECTION OF NUCLEAR POWER PLANT CONTROL ROOM OPERATORS AGAINST AN ACCIDENTAL CHLORINE RELEASE	–	–	–	–	–	–	–	–	–	–	44	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.97	INSTRUMENTATION FOR LIGHT WATER-COOLED NUCLEAR POWER PLANTS TO ACCESS PLANT CONDITIONS DURING AND FOLLOWING AN ACCIDENT	–	–	–	–	45	45	–	45	–	–	–	–	45	–	–	45	–	–	–	–	45	45	–	–	–	–	–	–	–	45	45	–	45	X	–	–	–	–	
RG 1.100	SEISMIC QUALIFICATION OF ELECTRIC EQUIPMENT FOR NUCLEAR POWER PLANTS	31	31	–	31	31	31	31	31	–	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	–	–	31	31	31	–	–	31	31	57	31	32	
RG 1.105	INSTRUMENT SPANS AND SETPOINTS	38	38	38	38	38	38	38	38	–	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	–	–	–	–	–	–	–	–	–	–	–	–	38	
RG 1.106	THERMAL OVERLOAD PROTECTION FOR ELECTRIC MOTORS ON MOTOR OPERATED VALVES	–	–	–	–	38	38	38	–	–	38	38	38	38	38	–	38	38	38	38	–	38	38	38	38	38	–	–	–	–	–	–	–	–	–	–	–	38	–	
RG 1.108	PERIODIC TESTING OF DIESEL GENERATOR UNITS USED AS ONSITE ELECTRIC POWER SYSTEMS AT NUCLEAR POWER PLANTS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	38	–	–	–	–	38	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.114	GUIDANCE ON BEING OPERATOR AT THE CONTROLS OF A NUCLEAR POWER PLANT	–	–	–	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	X 38	–	X 38	X 38	
RG 1.118	PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS (46)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
RG 1.120	FIRE PROTECTION GUIDELINES FOR NUCLEAR POWER PLANTS (8)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	

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TABLE 7.1-2

APPLICABLE CRITERIA (Continued)

		REACTOR TRIP SYSTEM (RTS) 7.2			ENGINEERED SAFETY FEATURES SYSTEM (ESF) 7.3										ENGINEERED SAFETY FEATURES SUPPORTING SYSTEMS (ESF SUPPORTING)					SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4							SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SRSS) 7.4				SAFETY RELATED DISPLAY INSTRUMENTS (SR) 7.5				ALL OTHER INSTRUMENT SYSTEMS REQUIRED FOR SAFETY 7.6					CONTROL SYSTEMS NOT REQUIRED FOR SAFETY 7.7 (1)
		NSSS INPUTS	RCP INPUTS	TURBINE INPUTS (2)	7.3 ESFAS	6.2.2 RB HEAT REMOVAL	6.2.3 RB AIR PURIFICATION AND CLEANUP	6.2.4 CONTAINMENT ISOLATION	6.2.5 COMBUSTIBLE GAS CONTROL	6.2.6 CONTAINMENT LEAKAGE TESTING (3)	6.3 SI	6.4 HABITABILITY SYSTEMS	6.5 FISSION PRODUCT REMOVAL AND CONTROL SYSTEMS	10.4.9 EMERGENCY FEEDWATER	9.2.2 CC SYSTEM	9.5 DG SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	6.2, 9.4 HVAC SYSTEMS (4)	9.2.2 CC SYSTEM	9.5 DG SYSTEM	10.4.9 EF SYSTEM	9.2.1 SW SYSTEM	9.4.7 VU SYSTEM	10.3 MS SYSTEM (5)	6.2, 9.4 HVAC SYSTEMS (4)	9.3.4 CHARGING PUMPS (6)	9.3.4 BA TRANSFER PUMPS	CREP MONITORING INDICATORS W	CREP MONITORING INDICATORS BOP	PAM W	PAM BOP	ESF MONITOR LIGHTS W	ESF MONITOR LIGHTS BOP	7.6.1 I & C POWER SUPPLY SYSTEM	7.6.2 RHR INTERLOCKS	7.6.3 REFUELING INTERLOCKS	7.6.4 ACCUMULATOR MOTOR OPERATED VALVES	7.6.5 LEAK DETECTION SYSTEMS	
	EICSB BRANCH TECHNICAL POSITIONS																																							
BTP EICSB 1	BACKFITTING OF THE PROTECTION AND EMERGENCY POWER SYSTEMS OF NUCLEAR REACTORS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 3	ISOLATION OF LOW PRESSURE SYSTEMS FROM THE HIGH PRESSURE REACTOR COOLANT SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X 11	–	–	–	
BTP EICSB 4	REQUIREMENTS ON MOTOR OPERATED VALVES IN THE ECCS ACCUMULATOR LINES	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	47	–	
BTP EICSB 5	SCRAM BREAKER TEST REQUIREMENTS - TECHNICAL SPECIFICATIONS	X 48	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	v	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 9	DEFINITION AND USE OF "CHANNEL - CALIBRATION" - TECHNICAL SPECIFICATIONS (49)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 10	ELECTRICAL AND MECHANICAL EQUIPMENT SEISMIC QUALIFICATION PROGRAM	31	31	–	31	31	31	31	31	–	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	–	–	31	31	31	–	–	31	31	57	31	32	
BTP EICSB 12	PROTECTION SYSTEM TRIP POINT CHANGES FOR OPERATION WITH REACTOR COOLANT PUMPS OUT OF SERVICE	50	–	–	50	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 13	DESIGN CRITERIA FOR AUXILIARY FEEDWATER SYSTEMS	–	–	–	X	–	–	–	–	–	–	–	–	X	–	X	X	X	X	–	X	X	X	X	X	X	–	–	–	–	–	X	–	X	X	–	–	–	–	
BTP EICSB 14	SPURIOUS WITHDRAWALS OF SINGLE CONTROL RODS IN PRESSURIZED WATER REACTORS (51)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 15	REACTOR COOLANT PUMP BREAKER QUALIFICATION (52)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 16	CONTROL ELEMENT ASSEMBLY (CEA) INTERLOCKS IN COMBUSTION ENGINEERING REACTORS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 18	APPLICATION OF THE SINGLE FAILURE CRITERIA TO MANUALLY CONTROLLED ELECTRICALLY OPERATED VALVES	–	–	–	–	–	–	–	–	–	53	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 19	ACCEPTABILITY OF DESIGN CRITERIA FOR HYDROGEN MIXING AND DRYWELL VACUUM RELIEF SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 20	DESIGN OF INSTRUMENTATION AND CONTROLS PROVIDED TO ACCOMPLISH CHANGEOVER FROM INJECTION TO RECIRCULATION MODE	–	–	–	X 54	–	–	–	–	–	X 54	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	X	–	–	–	–	–	–	–	–	
BTP EICSB 21	GUIDE FOR APPLICATION OF REGULATORY GUIDE 1.47	–	–	–	43	43	43	43	43	–	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	–	–	–	–	–	–	–	43	–	–	–	–	
BTP EICSB 22	GUIDE FOR APPLICATION OF REGULATORY GUIDE 1.22	X	–	–	41	41	41	41	41	–	30 41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	–	–	–	–	10	10	–	–	–	24	–	30	–	
BTP EICSB 23	QUALIFICATION OF SAFETY RELATED DISPLAY INSTRUMENTATION FOR POST ACCIDENT CONDITION MONITORING AND SAFE SHUTDOWN	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	10	10	–	–	–	–	–	–	–	
BTP EICSB 24	TESTING OF REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURE ACTUATION SYSTEM SENSOR RESPONSE TIMES	55	–	–	55	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 25	GUIDANCE FOR THE INTERPRETATION OF GENERAL DESIGN CRITERION 37 FOR TESTING THE OPERABILITY OF THE EMERGENCY CORE COOLING SYSTEM AS A WHOLE	–	–	–	X	–	–	–	–	–	X 20	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 26	REQUIREMENTS FOR REACTOR PROTECTION SYSTEM ANTICIPATORY TRIPS	X	–	2	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	
BTP EICSB 27	DESIGN CRITERIA FOR THERMAL OVERLOAD PROTECTION FOR MOTORS OF MOTOR OPERATED VALVES	–	–	–	–	56	56	56	–	–	56	–	56	–	56	–	56	–	–	56	–	–	56	–	56	–	–	–	–	–	–	–	–	–	–	–	–	56	–	

00-01

X IS DEFINED AS MEANING THE INSTRUMENT AND CONTROL SYSTEM AND COMPONENTS MEET THE REFERENCED CRITERIA

– IS DEFINED AS MEANING THE REFERENCED CRITERIA IS NOT APPLICABLE TO THE INSTRUMENT AND CONTROL SYSTEM AND COMPONENTS

NOTES TO TABLE 7.1-2

1. See Section 7.7 for a list of control systems typical of those not required for safety.

2. Although credit is not taken for the turbine trip inputs from the pressure sensors and turbine stop valves (as described in Section 7.2.1.2, Item 6) the circuits are classified as Associated with Class 1E, are seismically supported, and are separated in accordance with plant design criteria as described in Appendix 3A (RG 1.75) when located in Seismic Category 1 structures. Safety criteria apply only to the input devices and do not include the mechanical portions of the turbine generator.

3. Safety criteria apply only to those portions of the system that are part of containment.

4. Safety criteria apply only to those portions of HVAC systems that are safety related.

5. Safety criteria denoted as applicable for this input include only the main steam isolation valves, steam generator power operated relief valves, and valves that admit steam to the turbine driven emergency feedwater pump.

6. Applicability is limited to a chemical and volume control system function rather than a safety injection system function.

7. Instrumentation and associated wiring applies.

8. Design satisfies Branch Technical Position APCSB 9.5-1, Appendix A, to the extent outlined in the FPER. 00-01

9. Complies for those portions (components) of the system that are part of the protection system, i.e., inputs, logic, actuation device inputs, etc.

10. See Section 7.5.1 for discussion of compliance.

11. See Section 7.6.2 for discussion.

12. See Appendix 3A (RG 1.75) and Sections 7.1.2.2.1, 8.3.1.4, and 8.3.1.5 for discussion of compliance.

13. See Section 3.1.2 for discussion of compliance.

NOTES TO TABLE 7.1-2 (Continued)

14. See Section 3.1 for discussion of GDC 25. The analyses which are discussed in Chapter 15.0 are categorized as Condition II, III, and IV occurrences. These analyses show that the acceptance criteria for these categories are satisfied.

15. See Section 3.1 for discussion of GDC 26.

16. See Section 3.1 for discussion of GDC 27.

17. See Section 3.1 for discussion of GDC 28.

18. As noted in Section 7.4, nonaccident conditions are assumed.

19. See Sections 5.5.7, 6.3, and 7.6.5 for discussion of compliance.

20. See Sections 3.1.2, 6.3, and 7.6.5 for discussion of compliance.

21. The general philosophy of IEEE-279 is met by addressing redundancy and independence on a redundant subsystem basis, i.e., A loop/train and B loop/train basis. Testing can be performed on a loop basis consistent with the requirements of Sections 4.9 and 4.10 of IEEE-279.

22. For Westinghouse scope it is noted that:

    a. IEEE-279-1971 is not required as a design basis for systems, equipment, or components to which this note is applicable.

    b. The scope of IEEE-279-1971 is limited to the protection system from sensors to actuation devices inputs.

23. See Section 7.5.1 for discussion of post-accident monitoring.

24. See Section 7.6.2.2 for discussion of residual heat removal system interlocks.

25. Deleted (RNs 99-015 and 99-114) 00-01

26. Non-Class 1E components fed from Class 1E power source.

27. See Section 3.11 and Appendix 3A for discussion of compliance.

28. Applicable only to reactor building cooling unit fan motors.

29. See Section 7.1.2.11 for description of details of conformance to IEEE-338-1971.

NOTES TO TABLE 7.1-2 (Continued)

30. See Section 6.3.4.3 for description of safety injection system testing.

31. See Section 3.10 and Appendix 3A (RG 1.100) for discussion of compliance.

32. See Section 7.6.5 for description of leakage detection system. | 00-01

33. Complies as outlined in Section 7.1.2.7, Table 7.1-3 and Table 7.3-6.

34. See Sections 6.2.5 and 7.3.3 for discussion of hydrogen recombiner.

35. See Section 6.3.2.9 for discussion of safety injection.

36. Boric acid transfer pump power and control circuits are classified as Associated with Class 1E.

37. See Appendix 3A (RG 1.7), Section 6.2.5 and the response to NRC Question 031.56 for discussion of compliance.

38. See Appendix 3A for discussion of compliance.

39. See Appendix 3A (RG 1.11) and Section 6.2.6 for discussion of compliance.

40. Complies, see Section 3.7.4 and Appendix 3A (RG 1.12) for details.

41. Complies, for the protection system actuated devices, except as noted in Section 7.1.2.5.

42. See Appendix 3A (RG 1.45) and Section 5.2.7 for discussion of compliance.

43. Complies, as applicable to specific system components. Details are discussed in the response to NRC Question 031.49.

44. Complies, see Appendix 3A (RG 1.95).

45. See Appendix 3A (RG 1.97) and Sections 6.2.5 and 7.5 for discussion of compliance.

46. Reasons for non-applicability are outlined in Appendix 3A.

47. See Section 7.6.4 for discussion.

NOTES TO TABLE 7.1-2 (Continued)

48. See Section 7.2.2.2.3.10 for discussion. Also, see Chapter 16.0 (Technical Specifications), Table 4.3-1.

49. See Technical Specifications, Table 4.3-1. 00-01

50. See Technical Specifications, Section 3/4.4.1.

51. The results of analysis of a single rod cluster control assembly at full power are described in Section 15.3.

52. Accident analysis, as described in Sections 15.2.9 and 15.3.4, does not take credit for reactor coolant pump trip. Offsite electric system stability is described in Section 8.2.2.2.

53. BTP EICSB 18 applies to valves XVG8808A,B,C, XVG8884, XVG8885, XVG8886, XVG8888A,B, XVG8889, XVG8106, and XVG8133A,B in the Safety Injection System. See Chapter 16.0 (Technical Specifications), Section 3/4.5.1 and the responses to NRC Questions 040.18, 211.31, 211.32 and 211.37 for additional details. 99-01

54. See Section 6.3.2.7.

55. See Section 7.1.2.11 and Chapter 16.0 (Technical Specifications), Section 3/4.3.

56. See Appendix 3A (RG 1.106) for discussion of thermal overloads for electric motor operated valves.

57. See Section 9.1.4.1 (Item 6) and 9.1.4.3.1.2 (Item 5) and Tables 3.2-1, 3.2-2, and 3.2-3.

TABLE 7.1-3

CONFORMANCE WITH REGULATORY GUIDE 1.53 and IEEE 379-1972, FOR BALANCE OF PLANT SAFETY RELATED INSTRUMENTATION AND CONTROL SYSTEMS

Criterion		Degree of Compliance
REGULATORY GUIDE 1.53		
C.1	IEEE 379-1972	See IEEE 379-1972, comparison, below.
C.2	Continuity Checks	Except as outlined by Sections 7.1.2.5 and 7.3.2.2.5, components are designed to allow operation while being tested during reactor operation.
C.3	Interconnections	Channel separation is maintained and integrity is assured through use of isolating devices where interconnections may occur or suitable barriers are employed.
C.4	Protection System Logic and Actuator System	Actuator circuits are designed to prevent a single failure from causing loss of a protective function.
IEEE 379-1972		
3(1)	Redundancy	Redundancy is used and maintained to prevent a single failure in a channel or component from preventing operation of the redundant counterpart.
3(2)	Detectability	Control room indication and alarms are provided and are used in conjunction with periodic testing.
3(3)	Nondetectability	Not applicable, see Note 1.
3(4)	Multiple Faults	Not applicable, see Note 1.
3(5)	Completing Protective Functions	Systems are designed to prevent a single failure from resulting in noncompletion of the system protective function.
3(6)	DBE and Single Failure	Concurrent occurrence of a design basis event and a single failure was considered in the design. System protective function will not be lost under such circumstances.

TABLE 7.1-3 (Continued)

Criterion		Degree of Compliance
3(7)	Operational Reliability	Not applicable, but included in the design concept.
5.1	Classification	Not applicable, but included in the design concept.
5.2	Undetectable Failures	Not applicable, see Note 1. Also, see Regulatory Guide 1.53, Regulatory Position C.2, above.
5.3	Common Mode Failures	Concept was considered during design. Equipment qualification was used significantly in designing against common mode failures. Sections 3.10 and 3.11 outline qualification in more details.
6.1	General	See Note 1.
6.2	Channels	See Regulatory Guide 1.53, Regulatory Position C.3, above.
6.3	Protection System Logic	See Regulatory Guide 1.53, Regulatory Position C.4, above.
6.4	Actuator Circuit	See Regulatory Guide 1.53, Regulatory Position C.4, above.
Type 2 and 3 Single Failure Analysis		Equipment qualification was used significantly in designing against common mode failures. Sections 3.10 and 3.11 outline qualification in more detail.
6.6	Overall System - Failure Analysis	Concepts addressed were used during system design.

1. Each applicable FSAR section presents a safety evaluation which addresses the single failure criteria.

7.2 REACTOR TRIP SYSTEM

7.2.1 DESCRIPTION

7.2.1.1 System Description

The reactor trip system automatically keeps the reactor operating within a safe region by shutting down the reactor whenever the limits of the region are approached. The safe operating region is defined by several considerations such as mechanical/hydraulic limitations on equipment, and heat transfer phenomena. Therefore, the reactor trip system keeps surveillance on process variables which are directly related to equipment mechanical limitations, such as pressure, pressurizer water level (to prevent water discharge through safety valves, and uncovering heaters) and also on variables which directly affect the heat transfer capability of the reactor (e.g., flow and reactor coolant temperatures). Still other parameters utilized in the reactor trip system are calculated from various process variables. In any event, whenever a direct process or calculated variable reaches a setpoint the reactor will be shutdown in order to protect against either gross damage to fuel cladding or loss of system integrity which could lead to release of radioactive fission products into the containment.

The following systems make up the reactor trip system. Refer to References [1], [2], and [3] for additional background information.

1. Process Instrumentation and Control System.

2. Nuclear Instrumentation System.

3. Solid-State Logic Protection System.

4. Reactor Trip Switchgear.

5. Manual Actuation Circuit.

The reactor trip system consists of sensors which, when connected with analog circuitry consisting of 2 to 4 redundant channels, monitor various plant parameters and digital circuitry, consisting of 2 redundant logic trains, which receive inputs from the analog protection channels to complete the logic necessary to automatically open the reactor trip breakers.

Each of the two trains, A and B, is capable of opening a separate and independent reactor trip breaker, RTA and RTB, respectively and a bypass breaker, BYB and BYA, respectively. The 2 trip breakers in series connect three-phase a-c power from the rod drive motor generator sets to the rod drive power cabinets, as shown on Figure 7.2-1, Sheet 2. During plant power operation, a d-c undervoltage coil on each reactor trip breaker holds a trip plunger out against its spring, allowing the power to be available at the rod control power supply cabinets. For reactor trip, a loss of d-c voltage to the undervoltage coil, as well as energization of the shunt trip coil, trips open the breaker.

When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control rods fall, by gravity, into the core. The rods cannot be withdrawn until the trip breakers are manually reset. The trip breakers cannot be reset until the abnormal condition which initiated the trip is corrected. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed in Section 7.2.2.2.3.

7.2.1.1.1 Functional Performance Requirements

The reactor trip system automatically initiates reactor trip:

1. Whenever necessary to prevent fuel damage for an anticipated operational transient (Condition II).

2. To limit core damage for infrequent faults (Condition III).

3. So that the energy generated in the core is compatible with the design provisions to protect the reactor coolant pressure boundary for limiting fault conditions (Condition IV).

The reactor trip system initiates a turbine trip signal whenever reactor trip is initiated to prevent the reactivity insertion that would otherwise result from excessive reactor system cooldown. The turbine trip avoids unnecessary actuation of the engineered safety features actuation system.

The reactor trip system provides for manual initiation of reactor trip by operator action.

7.2.1.1.2 Reactor Trips

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the reactor trip system reaches a preset level. To ensure a reliable system, high quality design, components, manufacturing, quality control and testing is used. In addition to redundant channels and trains, the design approach provides a reactor trip system which monitors numerous system variables, therefore providing protection system functional diversity. The extent of this diversity has been evaluated for a wide variety of postulated accidents.

Table 7.2-1 provides a list of reactor trips which are described below.

1. Nuclear Overpower Trips

   The specific trip functions generated are as follows:

   a. Power range high neutron flux trip

      The power range high neutron flux trip circuit trips the reactor when 2 of the 4 power range channels reach the trip setpoint.

      There are 2 bistables (for each of the 4 power range channels), each with its own trip setting used for a high and a low range trip setting. The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually bypassed when 2 out of the 4 power range channels read above approximately 10% power (P-10). Three (3) out of the 4 channels below 10% automatically reinstates the trip function. Refer to Table 7.2-2 for a listing of all protection system interlocks.

   b. Intermediate range high neutron flux trip

      The intermediate range high neutron flux trip circuit trips the reactor when 1 out of the 2 intermediate range channels reaches the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if 2 out of 4 power range channels are above approximately 10% power (P-10). Three (3) out of the 4 power range channels below this value automatically reinstates the intermediate range high neutron flux trip. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing. This bypass action is annunciated on the control board.

   c. Source range high neutron flux trip

      The source range high neutron flux trip circuit trips the reactor when 1 of the 2 source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually bypassed when 1 of the 2 intermediate range channels reads above the P-6 setpoint value and is automatically reinstated when both intermediate range channels decrease below the P-6 setpoint value. This trip is also automatically bypassed by 2 out of 4 logic from the power range protection interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of 2 control board mounted switches. Each switch will reinstate the trip function in 1 of the 2 protection logic trains. The source range trip point is set between the P-6 setpoint

(source range cutoff power level) and the maximum source range power level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

d. Power range high positive neutron flux rate trip

This circuit trips the reactor when a sudden abnormal increase in nuclear power occurs in 2 out of 4 power range channels.

This trip provides DNB protection against rod ejection accidents of low worth from mid-power and is always active.

Figure 7.2-1, Sheet 3, shows the logic for all of the nuclear overpower and rate trips.

2. Core Thermal Overpower Trips

The specific trip functions generated are as follows:

a. Overtemperature ΔT trip

This trip protects the core against low DNBR and trips the reactor on coincidence as listed in Table 7.2-1 with 1 set of temperature measurements per loop. The setpoint for this trip is continuously calculated by analog circuitry for each loop by solving the following equation:

$$\Delta T_{setpoint} = \Delta T_O \left[K_1 - K_2 \left(\frac{1+\tau_1 S}{1+\tau_2 S} \right) \left(T_{avg} - T_{Oavg} \right) + K_3 (P - 2235) - f(\Delta\phi) \right]$$

Where:

ΔT_O	=	Indicated ΔT at rated thermal power
T_{avg}	=	Average reactor coolant temperature (°F)
T_{Oavg}	=	Indicated T_{avg} at rated thermal power
P	=	Pressurizer pressure (psig)
K_1	=	Preset bias
K_2	=	Preset gain which compensates for the temperature on the DNB limits
K_3	=	Preset gain which compensates for the effect of pressure on the DNB limits
τ_1, τ_2	=	Preset constants which compensate for piping and instrument time delay
s	=	Laplace transform operator (seconds^{-1})
$f(\Delta\phi)$	=	A function of the neutron flux difference between upper and lower long ion chambers (refer to Figure 7.2-2)

A separate long ion chamber unit supplies the flux signal for each overtemperature ΔT trip channel.

Increases in $\Delta\phi$ beyond a predefined deadband result in a decrease in trip setpoint. Refer to Figure 7.2-2.

The required 1 pressurizer pressure parameter per loop is obtained from separate sensors connected to 3 separate pressure taps at the top of the pressurizer. Refer to Section 7.2.2.3.3 for an analysis of this arrangement.

Figure 7.2-1, Sheet 5, shows the logic for overtemperature ΔT trip function.

b. Overpower ΔT trip

This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence as listed in Table 7.2-1, with 1 set of temperature measurements per loop. The setpoint for each channel is continuously calculated using the following equation:

$$\Delta T_{setpoint} = \Delta T_O \left[K_4 - K_5 \left(\frac{\tau_3 S}{1+\tau_3 S} \right) T_{avg} - K_6 \left(T_{avg} - T_{Oavg} \right) - f(\Delta\phi) \right]$$

Where:

ΔT_O	=	Indicated ΔT at rated thermal power
$f(\Delta\phi)$	=	A function of the neutron flux difference between upper and lower long ion chamber section (This function is set to 0 in the I and C instrumentation)
K_4	=	A preset bias
K_5	=	A constant which compensates for piping and instrument time delay
K_6	=	A constant which compensates for the change in density flow and heat capacity of the water with temperature.
T_{Oavg}	=	Indicated T_{avg} at rated thermal power
T_{avg}	=	Average reactor coolant temperature (°F)
τ_3	=	Preset time constant (seconds)
s	=	Laplace transform operator (seconds^{-1})

The source of temperature and flux information is identical to that of the overtemperature ΔT trip and the resultant ΔT setpoint is compared to the same ΔT. Figure 7.2-1, Sheet 5, shows the logic for this trip function.

3. Reactor Coolant System Pressurizer Pressure and Water Level Trips

The specific trip functions generated are as follows:

a. Pressurizer low pressure trip

The purpose of this trip is to protect against low pressure which could lead to DNB. The parameter being sensed is reactor coolant pressure as measured in the pressurizer. Above P-7 the reactor is tripped when the pressurizer measurements fall below preset limits. This trip is blocked below P-7 to permit startup. The trip logic and interlocks are given in Table 7.2-1. 00-01

The trip logic is shown on Figure 7.2-1, Sheet 6.

b. Pressurizer high pressure trip

The purpose of this trip is to protect the Reactor Coolant System against system overpressure.

The same sensors and transmitters used for the pressurizer low pressure trip are used for the high pressure trip except that separate bistables are used for trip. These bistables trip when uncompensated pressurizer pressure signals exceed preset limits on coincidence as listed in Table 7.2-1. There are no interlocks or permissives associated with this trip function.

The logic for this trip is shown on Figure 7.2-1, Sheet 6.

c. Pressurizer high water level trip

This trip is provided as a backup to the high pressurizer pressure trip and serves to prevent water relief through the pressurizer safety valves. This trip is blocked below P-7 to permit startup. The coincidence logic and interlocks of pressurizer high water level signals are given in Table 7.2-1.

The trip logic for this function is shown on Figure 7.2-1, Sheet 6.

4. Reactor Coolant System Low Flow Trips

These trips protect the core from DNB in the event of a loss of coolant flow situation. Figure 7.2-1, Sheet 5 shows the logic for these trips. The means of sensing the loss of coolant flow are as follows:

a. Low reactor coolant flow

The parameter sensed is reactor coolant flow. Four(4) elbow taps in each coolant loop are used as a flow device that indicates the status of reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. An output signal from 2 out of the 3 bistables in a loop would indicate a low flow in that loop.

The coincidence logic and interlocks are given in Table 7.2-1.

b. Reactor coolant pump undervoltage trip

This trip is required in order to protect against low flow which can result from loss of voltage to more than 1 reactor coolant pump motor (e.g., from loss of offsite power or reactor coolant pump breakers opening).

There are 3 undervoltage sensing relays connected for each pump (1 for each phase) at the motor side of each reactor coolant pump breaker. These relays provide an output signal when the pump voltage goes below approximately 70% of rated voltage. Signals from these relays are time delayed to prevent spurious trips caused by short term voltage perturbations. The coincidence logic and interlocks are given in Table 7.2-1.

c. Reactor coolant pump underfrequency trip

This trip protects against low flow resulting from pump underfrequency, for example a major power grid frequency disturbance. The function of this trip is to trip the reactor for an underfrequency condition greater than 2.5 Hz. The setpoint of the underfrequency relays is adjustable between 54.00 and 60.98 Hz (nominal). 99-01

There is 1 underfrequency sensing relay for each reactor coolant pump motor. Signals from relays for any 2 of the pump motors (time delayed up to approximately 0.1 seconds to prevent spurious trips caused by short term frequency perturbations) will trip the reactor if the power level is above P-7.

5. Steam Generator Trips

The specific trip functions generated are as follows:

a. Low feedwater flow trip

This trip protects the reactor from a sudden loss of heat sink. The trip is actuated by steam/feedwater flow mismatch (1 out of 2) in coincidence with low water level (1 out of 2) in any steam generator.

Figure 7.2-1, Sheet 7, shows the logic for this trip function.

There are no interlocks associated with this trip.

b. Low-Low steam generator water level trip

This trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch of insufficient magnitude to cause a low feedwater flow reactor trip. This trip is actuated on 2 out of 3 low-low water level signals occurring in any steam generator.

The logic is shown on Figure 7.2-1, Sheet 7.

6. Reactor Trip on a Turbine Trip (anticipatory)

The reactor trip on a turbine trip is actuated by 2 out of 3 logic from trip fluid pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip causes a direct reactor trip above P-9. The reactor trip on turbine trip provides additional protection and conservatism beyond that required for the health and safety of the public. This trip is included as part of good engineering practice and prudent design. No credit is taken in any of the safety analyses (Chapter 15) for this trip.

The turbine provides anticipatory trips to the reactor protection system from contacts which change position when the turbine stop valves close or when the turbine emergency trip fluid pressure goes below its setpoint.

One of the design bases considered in the protection system is the possibility of an earthquake. With respect to these contacts, their functioning is unrelated to a seismic event in that they are anticipatory to other diverse parameters which cause reactor trip. The contacts are shut during plant operation and open to cause reactor trip when the turbine is tripped. No power is provided to the protection system from the contacts; they merely serve to interrupt power to cause reactor trip. This design functions in a de-energize-to-trip fashion to cause a plant trip if power is interrupted in the trip circuitry. This ensures that the protection system will in no way be degraded by this anticipatory trip because seismic design considerations do not form part of the design bases for anticipatory trip sensors. (The reactor protection system cabinets which receive the inputs from the anticipatory trip sensors are, of course, seismically qualified as discussed in Section 3.10.) The anticipatory trips thus meet IEEE Standard 279-1971, including redundancy, single failure, etc. A unique variation in the separation criteria occurs in the turbine stop valve limit switches and in the turbine electro-hydraulic control cabinet (EHC). Separate stop valve limit switches are provided for each protection channel, but non-safety related control circuits are also on the limit switches. These circuits meet the intent of IEEE 279 for separation, since the non-safety circuits are not routed with or to any redundant protection channels. The train "B"

steam generator hi-hi level and safety injection trip signal from the reactor protection system to the EHC is not separated from non-safety related EHC circuits within the EHC cabinet. This meets the intent of IEEE 279 for separation also, since train "A" is isolated from the EHC and the EHC circuits are not routed with or to any train "A" circuits or devices. Seismic qualification of the contacts sensors is not required.

The logic for this trip is shown on Figure 7.2-1, Sheet 15.

7. Safety Injection Signal Actuation Trip

A reactor trip occurs when the safety injection system is actuated. The means of actuating the safety injection system are described in Section 7.3. This trip protects the core against a loss of reactor coolant or steam.

Figure 7.2-1, Sheet 8, shows the logic for this trip.

8. Manual Trip

The manual trip consists of 2 switches with 2 outputs on each switch. One(1) output is used to actuate the train A trip breaker and the train B bypass breaker; the other output actuates the train B trip breaker and the train A bypass breaker. Operating a manual trip switch removes the voltage from the undervoltage trip coil and energizes the shunt trip coil.

There are no interlocks which can block this trip. Figure 7.2-1, Sheet 3, shows the manual trip logic. The design conforms to Regulatory Guide 1.62 as shown in Figure 7.2-3.

7.2.1.1.3 Reactor Trip System Interlocks

1. Power Escalation Permissives

The overpower protection provided by the out of core nuclear instrumentation consists of 3 discrete, but overlapping, ranges. Continuation of startup operation or power increase requires a permissive signal from the higher range instrumentation channels before the lower range level trips can be manually blocked by the operator.

A 1 of 2 intermediate range permissive signal (P-6) is required prior to source range trip blocking. Source range trips are automatically reactivated when both intermediate range channels are below the permissive (P-6) setpoint. There are 2 manual reset switches for administratively reactivating the source range trip when between the permissive P-6 and P-10 setpoints, if required. Source range trip block is always maintained when above the permissive P-10 setpoint.

The intermediate range trip and power range (low setpoint) trip can only be blocked after satisfactory operation and permissive information are obtained from 2 of 4 power range channels. Four (4) individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently blocked (1 switch for each train). These trips are automatically reactivated when any 3 of the 4 power range channels are below the permissive (P-10) setpoint, thus ensuring automatic activation to more restrictive trip protection.

The development of permissives P-6 and P-10 is shown on Figure 7.2-1, Sheet 4. All of the permissives are digital; they are derived from analog signals in the nuclear power range and intermediate range channels.

Separation of circuits is maintained throughout the system where practical. An exception is in the wiring between the turbine stop valve limit switch junction box and the valve limit switches and where external circuits terminate within the junction box. However, wiring within the junction box is separated as far as is practical.

See Table 7.2-2 for the list of protection system interlocks.

2. Blocks at Reactor Trips at Low Power

Interlock P-7 blocks a reactor trip at lower power (below approximately 10% of full power) on a low reactor coolant flow in more than 1 loop, reactor coolant pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure, or pressurizer high water level. See Figure 7.2-1, Sheets 5 and 6 for permissive applications. The low power signal is derived from 3 out of 4 power range neutron flux signals below the setpoint in coincidence with 2 out of 2 turbine first stage pressure signals below the setpoint (low plant load). See Figure 7.2-1, Sheets 4 and 15, for the derivation of P-7.

The P-8 interlock blocks a reactor trip when the plant is below approximately 50% of full power, on a low reactor coolant flow in any 1 loop. The block action (absence of the P-8 interlock signal) occurs when 3 out of 4 neutron flux power range signals are below the setpoint. Thus, below the P-8 setpoint, the reactor will be allowed to operate with 1 inactive loop and trip will not occur until 2 loops are indicating low flow. See Figure 7.2-1, Sheet 4, for derivation of P-8, and Sheet 5 for applicable logic.

Interlock P-9 blocks a reactor trip following a turbine trip below 50% power. See Figure 7.2-1, Sheet 15, for the implementation of the P-9 interlock. See Figure 7.2-1, Sheet 4, for the derivation of P-9.

See Table 7.2-2 for the list of protection system blocks.

7.2.1.1.4 Coolant Temperature Sensor Arrangement

Narrow Range Hot and Cold Leg Temperature

The hot and cold loop temperature signals are required for input to the protection and control functions are obtained using thermowell mounted RTDs installed in each reactor coolant loop.

The hot leg temperature measurement in each loop is accomplished using 3 fast response narrow range dual element RTDs mounted in thermowells. The hot leg thermowells are located within the 3 scoops previously used for the RTD bypass manifold as locations 120° apart in the cross sectional sleeve. The scoops were modified by drilling a flow hole in the top of the scoops so that water flows in through the existing holes in the leading edge of the scoop, past the RTD and out through the new drilled hole.

Due to temperatures streaming, the 3 fast response hot leg RTDs are electronically averaged to generate the hot leg temperature.

The cold leg temperature measurements in each loop are accomplished by 1 fast response narrow range dual element RTD. The existing cold leg RTD bypass penetration nozzle was modified to accept the thermowell and RTD. Temperature streaming in the cold leg is not a concern due to the mixing action of the reactor coolant pump.

7.2.1.1.5 Pressurizer Water Level Reference Leg Arrangement

The design of the pressurizer water level instrumentation employs the usual tank level arrangement using differential pressure between an upper and a lower tap on a column of water. A reference leg connected to the upper tap is kept full of water by condensation of steam at the top of the leg.

7.2.1.1.6 Analog System

The analog system consists of two instrumentation systems; the process instrumentation system and the Nuclear Instrumentation System.

Process instrumentation includes those devices (and their interconnection into systems) which measure temperature, pressure, fluid flow, fluid level as in tanks or vessels, and occasionally physiochemical parameters such as fluid conductivity or chemical concentration. Process instrumentation specifically excludes nuclear and radiation measurements. The process instrumentation includes the process measuring devices, power supplies, indicators, recorders, alarm actuating devices, controllers, signal conditioning devices, etc., which are necessary for day-to-day operation of the nuclear steam supply system as well as for monitoring the plant and providing initiation of protective functions upon approach to unsafe plant conditions.

The primary function of nuclear instrumentation is to protect the reactor by monitoring the neutron flux and generating appropriate trips and alarms for various phases of reactor operating and shutdown conditions. It also provides a secondary control function and indicates reactor status during startup and power operation. The nuclear instrumentation system uses information from 3 separate types of instrumentation channels to provide 3 discrete protection levels. Each range of instrumentation (source, intermediate, and power) provides the necessary overpower reactor trip protection required during operation in that range. The overlap of instrument ranges provides reliable continuous protection beginning with source level through the intermediate and low power level. As the reactor power increases, the overpower protection level is increased by administrative procedures after satisfactory higher range instrumentation operation is obtained. Automatic reset to more restrictive trip protection is provided when reducing power.

Various types of neutron detectors, with appropriate solid-state electronic circuitry, are used to monitor the leakage neutron flux from a completely shutdown condition to 120% of full power. The power range channels are capable of recording overpower excursions up to 200% of full power. The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary. The lowest range ("source" range) covers 6 decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This is generally greater than 2 counts per second. The next range ("intermediate" range) covers ten plus decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation ("power" range) covers approximately 2 decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range.

The system described above provides control room indication and recording of signals proportional to reactor neutron flux during core loading, shutdown, startup and power operation, as well as during subsequent refueling. Startup rate indication for the source and intermediate range channels is provided at the control board. Reactor trip, rod stop, control and alarm signals are transmitted to the reactor control and protection system for automatic plant control. Equipment failures and test status information are annunciated in the control room.

See References [1] and [2] for additional background information on the process and nuclear instrumentation systems.

7.2.1.1.7 Solid-State Logic Protection System

The solid-state logic protection system takes binary inputs (voltage/no voltage) from the process and nuclear instrument channels corresponding to conditions (normal/abnormal) of plant parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage trip attachment and shunt trip auxiliary relay coils of the reactor trip circuit breakers

when the necessary combination of signals occur. The system also provides annunciator, status light and computer input signals which indicate the condition of bistable input signals, partial trip and full trip functions and the status of the various blocking, permissive and actuation functions. In addition the system includes means for semi-automatic testing of the logic circuits. Refer to Reference [3] for background information.

7.2.1.1.8 Isolation Amplifiers

Westinghouse considers it advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel, as permitted by IEEE Standard 279-1971.

Analog signals derived from protection channels for nonprotective functions are obtained through isolation amplifiers located in the analog protection racks. By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring.

7.2.1.1.9 Energy Supply and Environmental Variations

The energy supply for the reactor trip system, including the voltage and frequency variations, is described in Section 7.6 and Chapter 8. The environmental variations, throughout which the system will perform, is given in Section 3.11 and Chapter 8.

7.2.1.1.10 Setpoints

The setpoints that require trip action are given in the Technical Specifications. A detailed discussion on setpoints is found in Section 7.1.2.1.9.

7.2.1.1.11 Seismic Design

The seismic design considerations for the reactor trip system are given in Section 3.10. This design meets the requirements of Criterion 2 of the 1971 General Design Criteria (GDC).

7.2.1.2 <u>Design Bases Information</u>

The information given below presents the design bases information requested by Section 3 of IEEE Standard 279-1971. Functional logic diagrams are presented in Figure 7.2-1.

7.2.1.2.1 Generating Station Conditions

The following are the generating station conditions requiring reactor trip:

1. DNBR approaching the safety limit.

2. Power density (kilowatts per foot) approaching rated value for Condition II faults (see Chapter 4 for fuel design limits).

3. Reactor Coolant System overpressure creating stresses approaching the limits specified in Chapter 5.

7.2.1.2.2 Generating Station Variables

The following are the variables required to be monitored in order to provide reactor trips (see Table 7.2-1).

1. Neutron flux.

2. Reactor coolant temperature.

3. Reactor coolant system pressure (pressurizer pressure).

4. Pressurizer water level.

5. Reactor coolant flow.

6. Reactor coolant pump operational status (voltage and frequency).

7. Steam generator feedwater flow.

8. Steam generator water level.

9. Turbine generator operational status (trip fluid pressure and stop valve position).

10. Steam flow

7.2.1.2.3 Spatially Dependent Variables

The following variable is spatially dependent:

1. Reactor coolant temperature (see Section 7.3.1.2 for a discussion of this variable spatial dependence).

7.2.1.2.4 Limits, Margins and Setpoints

The parameter values that will require reactor trip are given in the Technical Specifications, and in Chapter 15, Accident Analyses. Chapter 15 proves that the setpoints used in Chapter 16 are conservative. 00-01

The setpoints for the various functions in the reactor trip system have been analytically determined such that the operational limits so prescribed will prevent fuel rod clad damage and loss of integrity of the reactor coolant system as a result of any ANS Condition II incident (anticipated malfunction). As such, during any ANS Condition II incident, the reactor trip system limits the following parameters to:

1. Minimum DNBR ≥ safety limit.

2. Maximum system pressure ≤ 2750 psia

3. Fuel rod maximum linear power for determination of protection setpoints ≤ 18.0 kW/foot

The accident analyses described in Section 15.2 demonstrate that the functional requirements as specified for the reactor trip system are adequate to meet the above considerations, even assuming, for conservatism, adverse combinations of instrument errors (refer to Table 15.3-1). A discussion of the safety limits associated with the reactor core and reactor coolant system, plus the limiting safety system setpoints, are presented in the Technical Specifications.

7.2.1.2.5 Abnormal Events

The malfunctions, accidents or other unusual events which could physically damage reactor trip system components or could cause environmental changes are as follows:

1. Earthquakes (see Chapters 2 and 3).

2. Fire (see Section 9.5).

3. Missiles (see Section 3.5).

4. Flood (see Chapters 2 and 3).

5. Wind and Tornadoes (see Section 3.3).

The reactor trip system fulfills the requirements of IEEE Standard 279-1971 to provide automatic protection and to provide initiating signals to mitigate the consequences of faulted conditions.

7.2.1.2.6 Minimum Performance Requirements

1. Reactor trip system response times

   Reactor trip system response time is defined in Section 7.1. Typical maximum allowable time delays in generating the reactor trip signal are tabulated in Table 7.2-3. (See Section 7.1.2.11 for a discussion of periodic response time verification capabilities.)

2. Reactor trip accuracies

   Accuracy is defined in Section 7.1. Reactor trip accuracies are tabulated in Table 7.2-3. An additional discussion on accuracy is found in Section 7.1.2.1.9.

3. Protection system ranges

   Typical protection system ranges are tabulated in Table 7.2-3. Range selection for the instrumentation covers the expected range of the process variable being monitored during power operation. Limiting setpoints are at least 5% from the end of the instrument span.

7.2.1.3 <u>Final Systems Drawings</u>

Functional block diagrams, electrical elementaries and other drawings required to assure electrical separation and perform a safety review are provided in the safety-related drawing package as discussed in Section 1.7.

7.2.2 ANALYSES

7.2.2.1 <u>Failure Mode and Effects Analyses</u>

An analysis of the reactor trip system has been performed. Results of this study and a fault tree analysis are presented in Reference [4].

7.2.2.2 <u>Evaluation of Design Limits</u>

While most setpoints used in the reactor protection system are fixed, there are variable setpoints, most notably the overtemperature ΔT and overpower ΔT setpoints. All setpoints in the reactor trip system have been selected on the basis of engineering design or safety studies. The capability of the reactor trip system to prevent loss of integrity of the fuel cladding and/or Reactor Coolant System pressure boundary during Condition II and III transients is demonstrated in Chapter 15. These accident analyses are carried out using those setpoints determined from results of the engineering design studies. Setpoint limits are presented in the Technical Specifications. A discussion of the intent for each of the various reactor trips and the accident analyses (where appropriate) which utilize this trip is presented below. It should be noted that the

selection trip setpoints all provide for margin before protection action is actually required to allow for uncertainties and instrument errors. The design meets the requirements of Criteria 10 and 20 of the 1971 GDC.

7.2.2.2.1 Trip Setpoint Discussion

The accident analysis shows that below the DNBR safety limit, a potential for local fuel cladding failure exists. The DNBR existing at any point in the core for a given core design can be determined as a function of the core inlet temperature, power output, operating pressure and flow. Consequently, core safety limits in terms of a DNBR equal to the safety limit for the hot channel can be developed as a function of core ΔT, T_{avg} and pressure for a specified flow as illustrated by the solid lines in Figure 15.1-1. Also shown as solid lines in Figure 15.1-1 are the loci of conditions equivalent to 118% of power as a function of ΔT and T_{avg} representing the overpower (kW/ft) limit on the fuel. The dashed lines indicate the maximum permissible setpoint (ΔT) as a function of T_{avg} and pressure for the overtemperature and overpower reactor trip. Actual setpoint constants in the equation representing the dashed lines are as given in the Technical Specifications. These values are conservative to allow for instrument errors. The design meets the requirements of Criteria 10, 15, 20, and 29 of the 1971 GDC.

DNBR is not a directly measurable quantity; however, the process variables that determine DNBR are sensed and evaluated. Small isolated changes in various process variables may not individually result in violation of a core safety limit; whereas the combined variations, over sufficient time, may cause the overpower or overtemperature safety limit to be exceeded. The design concept of the reactor trip system takes cognizance of this situation by providing reactor trips associated with individual process variables in addition to the overpower/overtemperature safety limit trips. Process variable trips prevent reactor operation whenever a change in the monitored value is such that a core or system safety limit is in danger of being exceeded should operation continue. Basically, the high pressure, low pressure and overpower/overtemperature ΔT trips provide sufficient protection for slow transients as opposed to such trips as low flow or high flux which will trip the reactor for rapid changes in flow or flux, respectively, that would result in fuel damage before actuation of the slower responding ΔT trips could be effected.

Therefore, the reactor trip system has been designed to provide protection for fuel cladding and Reactor Coolant System pressure boundary integrity where: 1) a rapid change in a single variable or factor which will quickly result in exceeding a core or a system safety limit, and 2) a slow change in 1 or more variables will have an integrated effect which will cause safety limits to be exceeded. Overall, the reactor trip system offers diverse and comprehensive protection against fuel cladding failure and/or loss of reactor coolant system integrity for Condition II and III accidents. This is demonstrated by Table 7.2-4 which lists the various trips of the reactor trip system, the corresponding Technical Specification on safety limits and safety system settings and the appropriate accident discussed in the safety analyses in which the trip could be utilized.

The design meets the requirements of Criterion 21 of the 1971 GDC.

Preoperational testing is performed on reactor trip system components and systems to determine equipment readiness for startup. This testing serves as a further evaluation of the system design.

Analyses of the results of Condition I, II, III, and IV events, including considerations of instrumentation installed to mitigate their consequences are presented in Chapter 15. The instrumentation installed to mitigate the consequences of load rejection and turbine trip is given in Section 7.4.

7.2.2.2.2 Reactor Coolant Flow Measurement

The elbow taps used on each loop in the primary coolant system are instrument devices that indicate the status of the reactor coolant flow. The basic function of this device is to provide information as to whether or not a reduction in flow has occurred. The correlation between flow and elbow tap signal is given by the following equation:

$$\frac{\Delta P}{\Delta P_O} = \left(\frac{W}{W_O}\right)^2$$

where ΔP_0 is the pressure differential at the reference flow, w_0, and ΔP is the pressure differential at the corresponding flow, w. The full flow reference point is established during initial plant startup. The low flow trip point is then established by extrapolating along the correlation curve. The expected absolute accuracy of the channel is within ± 10% of full flow and field results have shown the repeatability of the trip point to be within ± 1%.

7.2.2.2.3 Evaluation of Compliance to Applicable Codes and Standards

The reactor trip system meets the criteria of the General Design Criteria as indicated. The reactor trip system meets the requirements of Section 4 of IEEE Standard 279-1971 as indicated below.

7.2.2.2.3.1 General Functional Requirement

The protection system automatically initiates appropriate protective action whenever a condition monitored by the system reaches a preset level. Functional performance requirements are given in Section 7.2.1.1.1. Section 7.2.1.2.4 presents a discussion of limits, margins and setpoints; Section 7.2.1.2.5 discusses unusual (abnormal) events; and Section 7.2.1.2.6 presents minimum performance requirements.

7.2.2.2.3.2 Single Failure Criterion

The protection system is designed to provide 2, 3, or 4 instrumentation channels for each protective function and 2 logic train circuits. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required. Loss of input power to a channel or logic train will result in a signal calling for a trip. 00-01
This design meets the requirements of Criterion 23 of the 1971 GDC.

To prevent the occurrence of common mode failures, such additional measures as functional diversity, physical separation, and testing as well as administrative control during design, production, installation and operation are employed. The design meets the requirements of Criteria 21 and 22 of the 1971 GDC.

7.2.2.2.3.3 Quality of Components and Modules

For a discussion on the quality of the components and modules used in the reactor trip system, refer to Chapter 17. The quality assurance applied conforms to Criterion 1 of the 1971 GDC.

7.2.2.2.3.4 Equipment Qualification

For a discussion of the type tests made to verify the performance requirements, refer to Section 3.11. The test results demonstrate that the design meets the requirements of Criterion 4 of the 1971 GDC.

7.2.2.2.3.5 Channel Integrity

Protection system channels required to operate in accident conditions maintain necessary functional capability under extremes of conditions relating to environment, energy supply, malfunctions, and accidents. The energy supply for the reactor trip system is described in Section 7.6 and Chapter 8. The environmental variations, throughout which the system will perform is given in Section 3.11.

7.2.2.2.3.6 Independence

Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating modules in different protection cabinets. Each redundant protection channel set is energized from a separate a-c power feed. This design meets the requirements of Criterion 21 of the 1971 GDC.

Two(2) reactor trip breakers are actuated by 2 separate logic matrices which interrupt power to the control rod drive mechanisms. The breaker main contacts are connected in series with the power supply so that opening either breaker interrupts power to all full length control rod drive mechanisms, permitting the rods to free fall into the core (see Figure 7.1-1).

The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. Generally, 2 or more diverse protection functions would terminate an accident before intolerable consequences could occur. This design meets the requirements of Criterion 22 of the 1971 GDC.

7.2.2.2.3.7 Control and Protection System Interaction

The protection system is designed to be independent of the control system. In certain applications the control signals and other nonprotective functions are derived from individual protective channels through isolation amplifiers. The isolation amplifiers are classified as part of the protection system and are located in the analog protective racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation amplifiers are designed such that a short circuit, open circuit, or the application of credible fault voltages from within the cabinets on the isolated output portion of the circuit (i.e., the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation amplifiers are never returned to the protective racks. This design meets the requirements of Criterion 24 of the 1971 GDC and paragraph 4.7 of IEEE Standard 279-1971.

Moreover, Westinghouse programs in the period of late 1973 to mid 1976 have demonstrated by tests that credible faults or interference on cables associated with protection system racks cannot degrade system performance. The nuclear instrumentation and solid state protection systems tests are reported in the "Westinghouse Protection System Noise Tests" which were accepted by the NRC in support of the Diablo Canyon Application (Docket Numbers 50-275 and 50-323). The tests on the 7300 Series Process Control System are reported in Reference [5], a topical report accepted by the NRC.

In the Virgil C. Summer Nuclear Station, cables leaving the protection system racks are not routed with cables carrying potentials greater than those to which the systems were subjected in the Westinghouse test programs. Consequently these test programs are applicable to the Virgil C. Summer Nuclear Station and demonstrate that protection system performance cannot be degraded even if subjected to abnormal electrical conditions which far exceed those which can be reasonably postulated.

The results of applying various malfunction conditions on the output portion of the isolation amplifiers show that no significant disturbance to the isolation amplifier input signal occurred.

7.2.2.2.3.8 Derivation of System Inputs

To the extent feasible and practical, protection system inputs are derived from signals which are direct measures of the desired variables. Variables monitored for the various reactor trips are listed in Section 7.2.1.2.2.

7.2.2.2.3.9 Capability for Sensor Checks

The operational availability of each system input sensor during reactor operation is accomplished by cross checking between channels that bear a known relationship to each other and that have readouts available. Channel checks are discussed in Technical Specification 3/4.3 and Table 4.3-1 of the Technical Specifications.

7.2.2.2.3.10 Capability for Testing

The reactor trip system is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to assure complete system operation. The testing capabilities are in conformance with Regulatory Guide 1.22 as discussed in Section 7.1.2.5.

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation without initiating a protective action unless a trip condition actually exists. This is because of the coincidence logic required for the reactor trip. These tests may be performed at any plant power from cold shutdown to full power. Before starting any of these tests with the plant at power, all redundant reactor trip channels associated with the function to be tested must be in the normal (untripped) mode in order to avoid spurious trips. Setpoints are referenced in the precautions, limitations and setpoints portion of the plant technical manual.

1. Analog Channel Tests

   Analog channel testing is performed at the analog instrumentation rack set by individually introducing dummy input signals into the instrumentation channels and observing the tripping of the appropriate output bistables. Process analog output to the logic circuitry is interrupted during individual channel test by a test switch which, when thrown, de-energizes the associated logic input and inserts a proving lamp in the bistable output. Interruption of the bistable output to the logic circuitry for any cause (test, maintenance purposes, or removed from service) will cause that portion of the logic to be actuated (partial trip) accompanied by a partial trip alarm and channel status light actuation in the control room. Each channel contains those switches, test points, etc. necessary to test the channel. See Reference [1] for additional background information.

The following periodic tests of the analog channels of the protection circuits are performed:

a. T_{avg} and ΔT protection channel testing.

b. Pressurizer pressure protection channel testing.

c. Pressurizer water level protection channel testing.

d. Steam/feedwater flow protection channel testing.

e. Steam generator water level protection channel testing.

f. Reactor coolant low flow, underfrequency, and undervoltage protection channels.

g. Turbine first stage pressure channel testing.

2. Nuclear Instrumentation Channel Tests

The power range channels of the Nuclear Instrumentation System are tested by superimposing a test signal on the actual detector signal being received by the channel at the time of testing. The output of the bistable is not placed in a tripped condition prior to testing. Also, since the power range channel logic is 2 out of 4, bypass of this reactor trip function is not required.

To test a power range channel, a "TEST-OPERATE" switch is provided to require deliberate operator action and operation of which will initiate the "CHANNEL TEST" annunciator in the control room. Bistable operation is tested by increasing the test signal to its trip setpoint and verifying bistable relay operation by control board annunciator and trip status lights.

It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level. A reactor trip would occur when a second bistable trips. No provision has been made in the channel test circuit for reducing the channel signal level below that signal being received from the Nuclear Instrumentation System detector.

A Nuclear Instrumentation System channel which can cause a reactor trip through 1 of 2 protection logic (source or intermediate range) is provided with a bypass function which prevents the initiation of a reactor trip from that particular channel during the short period that it is undergoing test. These bypasses are annunciated in the control room.

The following periodic tests of the Nuclear Instrumentation System are performed:

a. Testing at plant shutdown

    (1) Source range testing.

    (2) Intermediate range testing.

    (3) Power range testing.

b. Testing below P-6 permissive power level

    (1) Source range testing.

c. Testing below P-10 permissive power level 00-01

    (1) Intermediate range testing.

    (2) Power range, low setpoint testing.

d. Testing above P-10 permissive power level

    (1) Power range testing.

Any deviations noted during the performance of these tests are investigated and corrected in accordance with the established calibration and troubleshooting procedures provided in the plant technical manual for the Nuclear Instrumentation System. Control and protection trip settings are indicated in the plant technical manual under precautions, limitations, and setpoints.

For additional background information on the Nuclear Instrumentation System see Reference [2].

3. Solid-State Logic Testing

The reactor logic trains of the reactor trip system are designed to be capable of complete testing at power. After the individual channel analog testing is complete, the logic matrices are tested from the train A and train B logic rack test panels. This step provides overlap between the analog and logic portions of the test program. During this test, all of the logic inputs are actuated automatically in all combinations of trip and nontrip logic. Trip logic is not maintained sufficiently long enough to permit opening of the reactor trip breakers. The reactor trip undervoltage coils are "pulsed" in order to check continuity. During logic testing of 1 train, the other train can initiate any required protective functions. Annunciation is provided in the control room to indicate when a train is in test (train output bypassed) and when a reactor trip breaker is bypassed. Logic testing can be performed in less than 30 minutes.

A direct reactor trip resulting from undervoltage or underfrequency on the reactor coolant pump buses is provided as discussed in Section 7.2.1 and shown on Figure 7.2-1. The logic for these trips is capable of being tested during power operation. When parts of the trip are being tested, the sequence is such that an overlap is provided between parts so that a complete logic test is provided. Thus complete testing of Westinghouse equipment is possible.

This design complies with the testing requirements of IEEE Standard 279-1971 and IEEE Standard 338-1971 discussed in Section 7.1.2.11.

The permissive and block interlocks associated with the reactor trip system and engineered safety features actuation system are given on Tables 7.2-2 and 7.3-3 and designated protection or "P" interlocks. As a part of the protection system, these interlocks are designed to meet the testing requirements of IEEE Standards 279-1971 and 338-1971.

Testing of all protection system interlocks is provided by the logic testing and semi-automatic testing capabilities of the solid-state protection system. In the solid-state protection system the undervoltage trip attachment and shunt trip auxiliary relay coils (reactor trip) and master relays (engineered safeguards actuation) are pulsed for all combinations of trip or actuation logic with and without the interlock signals. For example, reactor trip on low flow (2 out of 3 loops showing 2 out of 3 low flow) is tested to verify operability of the trip above P-7 and nontrip below P-7 (see Figure 7.2-1, Sheet 5). Interlock testing may be performed at power.

Testing of the logic trains of the reactor trip system includes a check of the input relays and a logic matrix check. The following sequence is used to test the system:

a. Check of input relays

During testing of the process instrumentation system and Nuclear Instrumentation System channels, each channel bistable is placed in a trip mode causing one input relay in train A and one in train B to de-energize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. Reactor trip inputs cause status lamps and annunciators on the control board to operate as shown in Figure 7.2-1. Either the Train A or Train B input relay operation will light the status lamp and annunciator.

Each train contains a multiplexing test switch. At the start of a process or Nuclear Instrumentation System test, this switch (in either train) is placed in the A + B position. The A + B position alternately allows information to be transmitted from the 2 trains to the control board. A steady status lamp and annunciator indicates that input relays in both trains have been de-energized. A flashing lamp means that the input relays in the 2 trains did not both de-energize. Contact inputs to the logic protection system, such as reactor coolant pump bus underfrequency relays, operate input relays which are tested by operating the remote contacts as described above and using the same type of indications as those provided for bistable input relays.

Actuation of the input relays provides the overlap between the testing of the logic protection system and the testing of those systems supplying the inputs to the logic protection system. Test indications are status lamps and annunciators on the control board. Inputs to the logic protection system are checked 1 channel at a time, leaving the other channels in service. For example, a function that trips the reactor when 2 out of 4 channels trip becomes a 1 out of 3 trip when 1 channel is placed in the trip mode. Both trains of the logic protection system remain in service during this portion of the test.

b. Check of logic matrices

Logic matrices are checked 1 train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch on the semi-automatic test panel in the train. At the completion of the logic matrix tests, one bistable in each channel of process instrumentation or nuclear instrumentation is tripped to check closure of the input error inhibit switch contacts.

The logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same terminals that connect to the input relay contacts. Thus there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the

reactor trip breaker undervoltage trip attachment and shunt trip auxiliary relay coils to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage coil armature cannot respond mechanically.

Test indications that are provided are an annunciator in the control room indicating that reactor trips from the train have been blocked and that the train is being tested, and green and red lamps on the semi-automatic tester to indicate a good or bad logic matrix test. Protection capability provided during this portion of the test is from the train not being tested.

The testing capability meets the requirements of Criterion 21 of the 1971 GDC.

4. Testing of Reactor Trip Breakers

Normally, reactor trip breakers 52/RTA and 52/RTB (see Figure 7.2-1, Sheet 2) are in service, and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). The following procedure describes the method used for testing the trip breakers: 98-01

a. With bypass breaker 52/BYA racked out, manually close and trip it to verify its operation.

b. Rack in and close 52/BYA. Manually trip 52/RTA through a protection system logic matrix while at the same time operating the "Auto Shunt Trip Block" pushbutton on the automatic shunt trip panel. This verifies operation of the Undervoltage Trip Attachment (UVTA) when the breaker trips. After reclosing RTA, trip it again by operation of the "Auto Shunt Trip Test" pushbutton on the automatic shunt trip panel. This is to verify tripping of the breaker through the shunt trip device.

c. Reset 52/RTA.

d. Trip and rack out 52/BYA.

e. Repeat above steps to test trip breaker 52/RTB using bypass breaker 52/BYB.

Auxiliary contacts of the bypass breakers are connected into the alarm system of their respective trains such that if either train is placed in test while the bypass breaker of the other train is closed, both reactor trip breakers and both bypass breakers will automatically trip.

Auxiliary contacts of the bypass breakers are also connected in such a way that if an attempt is made to close the bypass breaker in 1 train while the bypass breaker of the other train is already closed, both bypass breakers will automatically trip.

The train A and train B alarm systems operate separate annunciators in the control room. The 2 bypass breakers also operate an annunciator in the control room. Bypassing of a protection train with either the bypass breaker or with the test switches will result in audible and visual indications.

The complete reactor trip system is normally required to be in service. However, to permit online testing of the various protection channels or to permit continued operation in the event of a subsystem instrumentation channel failure, a Technical Specification, 3/4.3, defining the minimum number of operable channels has been formulated. This Technical Specification also defines the required restriction to operation in the event that the channel operability requirements cannot be met.

7.2.2.2.3.11 Channel Bypass or Removal from Operation

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation without initiating a protective action unless a trip condition actually exists. This is because of the coincidence logic required for reactor trip. Additional information is given in Section 7.3.2.2.5. 99-01

7.2.2.2.3.12 Operating Bypasses

Where operating requirements necessitate automatic or manual bypass of a protective function, the design is such that the bypass is removed automatically whenever permissive conditions are not met. Devices used to achieve automatic removal of the bypass of a protective function are considered part of the protective system and are designed in accordance with the criteria of this section. Indication is provided in the control room if some part of the system has been administratively bypassed or taken out of service.

7.2.2.2.3.13 Indication of Bypasses

Bypass indication is discussed in Section 7.1.2.6 and Appendix 3A.

7.2.2.2.3.14 Access to Means for Bypassing

The design provides for administrative control of access to the means for manually bypassing channels or protective functions.

7.2.2.2.3.15 Multiple Setpoints

For monitoring neutron flux, multiple setpoints are used. When a more restrictive trip setting becomes necessary to provide adequate protection for a particular mode of operation or set of operating conditions, the protective system circuits are designed to provide positive means or administrative control to assure that the more restrictive trip setpoint is used. The devices used to prevent improper use of less restrictive trip settings are considered part of the protective system and are designed in accordance with the criteria of this section.

7.2.2.2.3.16 Completion of Protective Action

The protection system is so designed that, once initiated, a protective action goes to completion. Return to normal operation requires action by the operator.

7.2.2.2.3.17 Manual Initiation

Switches are provided on the control board for manual initiation of protective action. Failure in the automatic system does not prevent the manual actuation of the protective functions. Manual actuation relies on the operation of a minimum of equipment.

7.2.2.2.3.18 Access

The design provides for administrative control of access to all setpoint adjustments, module calibration adjustments, and test points.

7.2.2.2.3.19 Identification of Protective Actions

Protective channel identification is discussed in Section 7.1.2.3. Indication is discussed in Section 7.2.2.2.3.20.

7.2.2.2.3.20 Information Read Out

The protective system provides the operator with complete information pertinent to system status and safety. All transmitted signals (flow, pressure, temperature, etc.) which can cause a reactor trip will be either indicated or recorded for every channel, including all neutron flux power range currents (top detector, bottom detector, algebraic difference and average of bottom and top detector currents).

Any reactor trip will actuate an alarm and an annunciator. Such protective actions are indicated and identified down to the channel level.

Alarms and annunciators are also used to alert the operator of deviations from normal operating conditions so that he may take appropriate corrective action to avoid a reactor trip. Actuation of any rod stop or trip of any reactor trip channel will actuate an alarm.

7.2.2.2.3.21 System Repair

The system is designed to facilitate the recognition, location, replacement, and repair of malfunctioning components or modules. Refer to the discussion in Section 7.2.2.2.3.10.

7.2.2.3 Specific Control and Protection Interactions

7.2.2.3.1 Neutron Flux

Four (4) power range neutron flux channels are provided for overpower protection. An isolated auctioneered high signal is derived by auctioneering of the 4 channels for automatic rod control. If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection but will not cause control rod movement because of the auctioneer. Two (2) out of 4 overpower trip logic will ensure an overpower trip if needed even with an independent failure in another channel.

In addition, channel deviation signals in the control system will give an alarm if any neutron flux channel deviates significantly from the average of the flux signals. Also, the control system will respond only to rapid changes in indicated neutron flux; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear power range channel will block manual and automatic rod withdrawal. The setpoint for this rod stop is below the reactor trip setpoint.

7.2.2.3.2 Coolant Temperature

The accuracy of the resistance temperature detector temperature measurements is demonstrated during plant startup. Tests compare with each other as well as with the temperature measurements obtained from cold leg piping of each loop. The comparisons are done with the Reactor Coolant System in an isothermal condition. The linearity of the ΔT detectors as a function of plant power is also checked during plant startup as far as reactor protection is concerned. Reactor trip system setpoints are based upon percentages of the indicated ΔT at nominal full power rather than on absolute values of ΔT. This is done to account for loop differences which are inherent. Therefore, the percent ΔT scheme is relative, not absolute, and therefore provides better protective action without the expense of accuracy. For this reason, the linearity of the ΔT signals as a function of power is of importance rather than the absolute values of the ΔT. As part of the plant startup tests, the resistance temperature detector signals will be compared with the core exit thermocouple signals.

The input signals to the reactor control systems are obtained from electronically isolated protection T_{avg} and Delta-T signals, (one per loop). A Median Signal Selector (MSS) is implemented in the reactor control system, one for T_{avg} and one for Delta-T. The MSS receives three signals as input and selects the median signal for input to the appropriate control system. Any single failure (high or low) in a calculated temperature will not result in adverse control system behavior since the failed high or low temperature signal will be rejected by the MSS. 00-01

Hence, the implementation of a MSS in the reactor coolant systems in conjunction with the 2 out of 3 protection logic satisfies the requirements of IEEE 279-1971, Section 4.7, "Control and Protection System Interaction."

In addition, channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the median value. Automatic rod withdrawal blocks and turbine runback (power demand reduction) will also occur if any 2 of the 4 overtemperature or overpower ΔT channels indicate an adverse condition. 00-01

7.2.2.3.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high and low pressure protection and as inputs to the overtemperature ΔT trip protection function. Pressurizer pressure is sensed by fast response pressure transmitters. Control signals are not derived from protection channels.

A spurious high pressure signal from one control channel can cause decreasing pressure by actuation of either spray or relief valves. Protection is provided in the low pressurizer pressure reactor trip and in the logic for safety injection to ensure low pressure protection.

Overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming the core continues to produce full power. The self-actuated safety valves are sized on the basis of steam flow from the pressurizer to accommodate this surge at a setpoint of 2500 psia and an accumulation of 3%. Note that no credit is taken for the relief capability provided by the power operated relief valves during this surge.

In addition, operation of any 1 of the power operated relief valves can maintain pressure below the high pressure trip point for most transients. The rate of pressure rise achievable with heaters is slow, and ample time and pressure alarms are available to alert the operator of the need for appropriate action.

One(1) tap on the pressurizer is shared for 1 each protection level and pressure transmitter, 2 control pressure transmitters and 1 wide range level transmitter. Redundancy is not compromised by having a shared tap since the logic for this trip is 2 out of 3. If the shared tap is plugged, the affected channels will remain static. If the impulse line bursts, the indicated pressure will drop to 0. In either case the fault is easily detectable, and the protective function remains operable.

7.2.2.3.4 Pressurizer Water Level

Three (3) pressurizer water level channels are used for reactor trip. Isolated signals from these channels are used for pressurizer water level control. A failure in the level control system could fill or empty the pressurizer at a slow rate (on the order of 30 minutes or more).

The high water level trip setpoint provides sufficient margin such that the undesirable condition of discharging liquid coolant through the safety valves is avoided. Even at full power conditions, which would produce the worst thermal expansion rates, a failure of the water level control would not lead to any liquid discharge through the safety valves. This is due to the automatic high pressurizer pressure reactor trip actuating at a pressure sufficiently below the safety valve setpoint.

For control failures which tend to empty the pressurizer, 2 out of 3 logic for safety injection action on low pressure ensures that the protection system can withstand an independent failure in another channel. In addition, ample time and alarms exist to alert the operator of the need for appropriate action.

7.2.2.3.5 Steam Generator Water Level and Feedwater Flow

The basic function of the reactor protection circuits associated with low steam generator water level and low feedwater flow is to preserve the steam generator heat sink for removal of long term residual heat. Should a complete loss of feedwater occur, the reactor would be tripped on coincidence of steam/feedwater flow mismatch and low steam generator water level or on low-low steam generator water level. In addition, redundant emergency feedwater pumps are provided to supply feedwater in order to maintain residual heat removal after trip. These reactor trips act before the steam generators are dry to reduce the required capacity and increase the starting time requirements of these emergency feedwater pumps and to minimize the thermal transient on the reactor coolant system and steam generators. Therefore, the following reactor trip circuits are provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient:

1. A mismatch in steam and feedwater flow coincident with low steam generator water level;

2. A low-low steam generator water level regardless of steam/feedwater flow mismatch;

It is desirable to minimize thermal transients on a steam generator for credible loss of feedwater accidents. Hence, it should be noted that controller malfunctions caused by a protection system failure affect only 1 steam generator; the steam generator level signal used in the feedwater control originates separately from that used in the low feedwater reactor trip.

A spurious high signal from the feedwater flow channel being used for control would cause a reduction in feedwater flow preventing that channel from ultimately tripping. However, the mismatch between steam demand and feedwater flow produced by this spurious signal will actuate alarms to alert the operator of this situation in time for manual correction. If the condition is allowed to continue and the mismatch is not sufficient to trip the reactor, reactor trip will occur on a low-low water level signal independent of indicated feedwater flow.

A spurious low signal from the feedwater flow channel being used for control would cause an increase in feedwater flow. The mismatch between steam flow and feedwater flow produced by the spurious signal would actuate alarms to alert the operator of the situation in time for manual correction. If the condition continues, a 2 out of 3 high-high steam generator water level signal in any loop, independent of the indicated feedwater flow, will cause feedwater isolation and trip the turbine. The turbine trip will result in a subsequent reactor trip if power is above the P-9 setpoint. The high-high steam 99-01
generator water level trip is an equipment protective trip preventing excessive moisture carryover which could damage the turbine blading.

In addition, the 3 element feedwater controller incorporates reset action on the level error signal, such that with expected controller settings a rapid increase or decrease in the flow signal would cause only a small change in level before the controller would compensate for the level error. A slow change in the feedwater signal would have no effect at all. A spurious low or high steam flow signal would have the same effect as high or low feedwater signal, discussed above.

A spurious high steam generator water level signal from the protection channel used for control will tend to close the feedwater valve. However, before a reactor trip would occur, 2 out of 3 channels for a steam generator would have to indicate a high water level. A spurious low steam generator water level signal will tend to open the feedwater valve. Again, before a reactor trip would occur, 2 out of 3 channels in a loop would have to indicate a low water level. Any slow drift in the water level signal will permit the operator to respond to the level alarms and take corrective action. Automatic protection is provided in case the spurious high level reduces feedwater flow sufficiently to cause low level in the steam generator. The reactor will trip either on a mismatch on steam and feedwater flow coincident with low water level or, ultimately, on low-low steam generator water level. Automatic protection is also provided in case the spurious low level signal increases feedwater flow sufficiently to cause high level in the steam generator. A turbine trip and feedwater isolation would occur on 2 out of 3 high-high steam generator water level in any loop.

7.2.2.4 Additional Postulated Accidents

Loss of plant instrument air or loss of component cooling water is discussed in Section 7.3.2. Load rejection and turbine trip are discussed in further detail in Section 7.7.

The control interlocks, called rod stops, that are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal are discussed in Section 7.7.1.4.1 and listed on Table 7.7-1. Excessively high power operation (which is prevented by blocking of automatic rod withdrawal), if allowed to continue, might lead to a safety limit (as given in the Technical Specifications) being reached. Before such a limit is reached, protection will be available from the reactor trip system. At the power levels of the rod block setpoints, safety limits have not been reached; and therefore these rod withdrawal stops do not come under the scope of safety-related systems, and are considered as control systems. 00-01

7.2.3 TESTS AND INSPECTIONS

The reactor trip system meets the testing requirements of IEEE Standard 338-1971 as discussed in Section 7.1.2.11. The testability of the system is discussed in Section 7.2.2.2.3. The initial test intervals are specified in the Technical Specifications. Written test procedures and documentation, conforming to the requirements of IEEE Standard 338-1971, will be available for audit by responsible personnel. Periodic testing complies with Regulatory Guide 1.22 as discussed in Sections 7.1.2.5 and 7.2.2.2.3. 00-01

7.2.4 REFERENCES

1. Reid, J. B., "Process Instrumentation for Westinghouse Nuclear Steam Supply Systems," WCAP-7913, January, 1973.

2. Lipchak, J. B., "Nuclear Instrumentation System," WCAP-8255, January, 1974.

3. Katz, D. N., "Solid State Logic Protection System Description," WCAP-7488-L Proprietary), March, 1971 and WCAP-7672 (Non-Proprietary), May, 1971.

4. Gangloff, W. C. and Loftus, W. D., "An Evaluation of Solid-State Logic Reactor Protection In Anticipated Transients," WCAP-7706-L (Proprietary) and WCAP-7706 Non-Proprietary), February, 1973.

5. Siroky, R. M. and Marasco, F. W., "7300 Series Process Control System Noise Tests," WCAP-8892A, June, 1977.

TABLE 7.2-1

LIST OF REACTOR TRIPS

	Reactor Trip	Coincidence Logic	Interlocks	Comments
1.	High neutron flux (Power Range)	2/4	Manual block of low setting permitted by P-10	High and low setting; manual block and automatic reset of low setting by P-10
2.	Intermediate range neutron flux	1/2	Manual block permitted by P-10	Manual block and automatic reset
3.	Source range neutron flux	1/2	Manual block permitted by P-6, interlocked with P-10	Manual block and automatic reset. Automatic block above P-10
4.	Power range high positive neutron flux rate	2/4	No interlocks	
5.	Overtemperature ΔT	2/3	No interlocks	
6.	Overpower ΔT	2/3	No interlocks	
7.	Pressurizer low pressure	2/3	Interlocked with P-7	Blocked below P-7
8.	Pressurizer high pressure	2/3	No interlocks	

TABLE 7.2-1 (Continued)

LIST OF REACTOR TRIPS

	Reactor Trip	Coincidence Logic	Interlocks	Comments
9.	Pressurizer high water level	2/3	Interlocked with P-7	Blocked below P-7
10.	Low reactor coolant flow	a. 2/3 in 2/3 loops b. 2/3 in any loop	Interlocked with P-7 Interlocked with P-8	Low flow in one loop will cause a reactor trip when above P-8 and a low flow in two loops will cause a reactor trip when above P-7; blocked below P-7
11.	Reactor coolant pump undervoltage	2/3	Interlocked with P-7	Low voltage permitted below P-7
12.	Reactor coolant pump underfrequency	2/3	Interlocked with P-7	Underfrequency on 2 motors will trip all reactor coolant pump breakers and cause reactor trip; blocked below P-7
13.	Low feedwater flow	1/2 in any loop[(1)]	No interlocks	
14.	Low-Low Steam Generator Water Level	2/3 in any loop	No interlocks	

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TABLE 7.2-1 (Continued)

LIST OF REACTOR TRIPS

	Reactor Trip	Coincidence Logic	Interlocks	Comments
15.	Safety injection signal	Coincident with actuation of safety injection	No interlocks	(See Section 7.3 for engineered safety features actuation conditions)
16.	Turbine trip (anticipatory)		Interlocked with P-9	Blocked below P-9
	a. Trip fluid pressure	2/3	Interlocked with P-9	Blocked below P-9
	b. Turbine stop valve close	4/4		
17.	Manual	1/2	No interlocks	

(1) 1/2 steam/feedwater flow mismatch in coincidence with 1/2 low steam generator water level.

TABLE 7.2-2

PROTECTION SYSTEM INTERLOCKS

I POWER ESCALATION PERMISSIVES

Designation	Derivation	Function
P-6	Presence of P-6: 1/2 neutron flux (intermediate range) above setpoint	Allows manual block of source range reactor trip
	Absence of P-6: 2/2 neutron flux (intermediate range) below setpoint	Defeats the block of source range reactor trip
P-10	Presence of P-10: 2/4 neutron flux (power range) above setpoint	Allows manual block of power range (low setpoint) reactor trip Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1) Blocks source range reactor trip (backup for P-6)
	Absence of P-10: 3/4 neutron flux (power range) below setpoint	Defeats the block of power range (low setpoint) reactor trip Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1) Input to P-7

TABLE 7.2-2 (Continued)

PROTECTION SYSTEM INTERLOCKS

II BLOCKS OF REACTOR TRIPS

Designation	Derivation	Function
P-7	Absence of P-7: 3/4 neutron flux (power range) below setpoint (from P-10) and 2/2 turbine first stage pressure below setpoint (from P-13)	Blocks reactor trip on: Low reactor coolant flow in more than one loop, undervoltage, underfrequency, pressurizer low pressure, and pressurizer high level 99-01
P-8	Absence of P-8: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on low reactor coolant flow in a single loop
P-9	Absence of P-9: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on turbine trip
P-13	2/2 turbine first stage pressure below setpoint	Input to P-7

TABLE 7.2-3

REACTOR TRIP SYSTEM INSTRUMENTATION

	Reactor Trip Signal	Range	Trip Accuracy	Time Response (sec)
1.	Power range high neutron flux	1 to 120% full power	± 1% of full power	0.5
2.	Intermediate range high neutron flux	10.2 decades of neutron flux overlapping source range by 5 decades and including 100% power	± 2.3% of full scale	0.5
3.	Source range high neutron flux	6 decades of neutron flux (1 to 10^6 counts/sec)	± 3.5% of full scale (1)	0.5
4.	Power range high positive neutron flux rate	± 15% of full	± 5% (1)	0.5
5.	Overtemperature ΔT	TH 530 to 650°F TC 510 to 630°F TAV 530 to 630°F PPRZR 1700 to 2500 psig F (Δ∅) - 50 to + 50% ΔT Setpoint 0 to 100°F	± 2% ΔT span	8.5

TABLE 7.2-3 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

	Reactor Trip Signal	Range	Trip Accuracy	Time Response (sec)
6.	overpower ΔT	TH 530 to 650°F TC 510 to 630°F TAV 530 to 630°F ΔT Setpoint 0 to 100°F (ΔØ) -50 to +50% ΔT	± 2% ΔT span	8.5
7.	Pressurizer low pressure	1700 to 2500 psig	± 18 psi	1.0
8.	Pressurizer high pressure	1700 to 2500 psig	± 14 psi	1.0
9.	Pressurizer high water level	Entire distance between taps	± 2.25% of full range Δp between taps at design temperature and pressure	2.0
10	Low reactor coolant flow	0 to 120% of rated flow	± 2.5% of full flow within range of 70% to 100% of full flow (1)	1.0
11.	Reactor coolant pump undervoltage	0 to 100% rated voltage	± 0.23% of rated voltage	1.5

TABLE 7.2-3 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

	Reactor Trip Signal	Range	Trip Accuracy	Time Response (sec)	
12.	Reactor coolant pump	54.00 to 60.98 Hz (nominal) underfrequency	± 0.005 Hz	0.6	99-01
13.	Low feedwater flow (2)	0 to 120% maximum calculated feedwater flow	± 6.5% (3)	1.5	
14.	Low-low steam generator water level	Total distance between narrow range steam generator level taps	± 2.25% of Δp signal over the pressure range of 700 to 1200 psig	1.5	
15.	Turbine trip from low hydraulic fluid pressure	Differential pressure range 400 to 1200 psig	± 1.5% of differential pressure range	0.6	00-01

(1) Reproducibility (see definitions in Section 7.1)

(2) 1/2 steam/feedwater flow mismatch in coincidence with 1/2 low steam generator water level.

(3) Channel accuracy of feedwater flow analog signal is ± 2.5% of maximum calculated feedwater flow.

Accuracy of steam flow signal is ± 3% of maximum calculated flow over the pressure range of 700 to 1200 psig.

TABLE 7.2-4

REACTOR TRIP CORRELATION

TRIP (1)	ACCIDENT (2)	TECH SPEC (3)	
1. Power Range High Neutron Flux Trip (Low Setpoint)	1. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	2.2.1 Table 2.2-1 # 2	
	2. Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)		
	3. Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection) (15.4.6)		
	4. Uncontrolled Boron Dilution (15.2.4)		00-01
2. Power Range High Neutron Flux Trip (High Setpoint)	1. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	2.2.1 Table 2.2-1 # 2	
	2. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)		
	3. Startup of an Inactive Reactor Coolant Loop (15.2.6)		
	4. Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)		
	5. Excessive Load Increase Incident (15.2.11)		
	6. Accidental Depressurization of the Main Steam System (15.2.13)		
	7. Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection) (15.4.6)		
	8. Uncontrolled Boron Dilution (15.2.4)		00-01
3. Intermediate Range High Neutron Flux Trip	1. Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	See Note 4 2.2.1 Table 2.2-1 # 5	

TABLE 7.2-4 (Continued)

REACTOR TRIP CORRELATION

TRIP [1]		ACCIDENT [2]	TECH SPEC [3]
4. Source Range High Neutron Flux Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition (15.2.1)	See Note 4 2.2.1 Table 2.2-1 # 6
5. Power Range High Positive Neutron Flux Rate Trip	1.	Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection) (15.4.6)	2.2.1 Table 2.2-1 # 3
6. Overtemperature ΔT Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)	See Note 1 2.2.1 Table 2.2-1 # 7
	2.	Uncontrolled Boron Dilution (15.2.4)	
	3.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	
	4.	Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)	
	5.	Excessive Load Increase Incident (15.2.11)	
	6.	Accidental Depressurization of the Reactor Coolant System (15.2.12)	
	7.	Accidental Depressurization of the Main Steam System (15.2.13)	
7. Overpower ΔT Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)	See Note 2 2.2.1 Table 2.2-1 # 8
	2.	Excessive Heat Removal Due to Feedwater System Malfunctions (15.2.10)	
	3.	Excessive Load Increase Incident (15.2.11)	
	4.	Accidental Depressurization of the Main Steam System (15.2.13)	
	5.	Major Secondary System Pipe Ruptures (15.4.2)	

TABLE 7.2-4 (Continued)

REACTOR TRIP CORRELATION

TRIP[1]		ACCIDENT[2]	TECH SPEC[3]
8. Pressurizer Low Pressure Trip	1.	Accidental Depressurization of the Reactor Coolant System (15.2.12)	2.2.1 Table 2.2-1 # 9
	2.	Loss of Reactor Coolant From Small Ruptured Pipes or From Cracks in Large Pipes Which Actuates ECCS (15.3.1)	
	3.	Major Reactor Coolant System Pipe Ruptures (LOCA) (15.4.1)	
	4.	Steam Generator Tube Rupture (15.4.3)	
	5.	Inadvertent Operation of the ECCS (15.2.14)	
9. Pressurizer High Pressure Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.2.2)	2.2.1 Table 2.2-1 # 10
	2.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	
10. Pressurizer High Water Level Trip	1.	Uncontrolled Rod Cluster Control Assembly Bank at Power (15.2.2)	2.2.1 Table 2.2-1 # 11
	2.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	
11. Low Reactor Coolant Flow	1.	Partial Loss of Forced Reactor Coolant Flow (15.2.5)	2.2.1 Table 2.2-1 # 12
	2.	Loss of Offsite Power to the Station Auxiliaries (15.2.9)	
	3.	Complete Loss of Forced Reactor Coolant Flow (15.3.4)	
12. Reactor Coolant Pump Undervoltage Trip	1.	Complete Loss of Forced Reactor Coolant Flow (15.3.4)	2.2.1 Table 2.2-1 # 15
13. Reactor Coolant Pump Underfrequency Trip	1.	Complete Loss of Forced Reactor Coolant Flow (15.3.4)	2.2.1 Table 2.2-1 # 16

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TABLE 7.2-4 (Continued)

REACTOR TRIP CORRELATION

	TRIP (1)		ACCIDENT (2)	TECH SPEC (3)
14.	Low Feedwater Flow Trip	1.	Loss of Normal Feedwater (15.2.8)	See Note 4 2.2.1 Table 2.2-1 # 14
		8.	Uncontrolled Boron Dilution (15.2.4)	
15.	Low-low Steam Generator Water Level Trip	1.	Loss of Normal Feedwater (15.2.8)	2.2.1 Table 2.2-1 # 13 00-01
		2.	Feedwater Line Break (15.4.2.2)	
16.	Reactor Trip on Turbine Trip	1.	Loss of External Electrical Load and/or Turbine Trip (15.2.7)	See Note 4 2.2.1 Table 2.2-1 # 17
		2.	Loss of Offsite Power to the Station Auxiliaries (15.2.9)	
		3.	Excessive Heat Removal Due to Feedwater System Malfunction (15.2.10)	
17.	Safety injection Signal Actuation Trip	1.	Accidental Depressurization of the Main Steam System (15.2.13)	See Note 5 2.2.1 Table 2.2-1 # 18
18.	Manual Trip (Chapter 15)		Available for all Accidents	See Note 4

(1) Trips are listed in order of discussion in Section 7.2

(2) References refer to accident analyses presented in Chapter 15.

(3) References refer to Virgil C. Summer Technical Specifications.

(4) A Technical Specification is not required because this trip is not assumed to function in the accident analyses.

(5) Accident assumes that the reactor is tripped at end of life (EOL) which is the worst initial condition for this case.

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7.3 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM

In addition to the requirements for a reactor trip for anticipated abnormal transients, the facility is provided with adequate instrumentation and controls to sense accident situations and initiate the operation of necessary engineered safety features. The occurrence of a limiting fault, such as a loss of coolant accident or a steam line break, requires a reactor trip plus actuation of one or more of the engineered safety features in order to prevent or mitigate damage to the core and Reactor Coolant System components, and ensure containment integrity.

In order to accomplish these design objectives the Engineered Safety Features System has proper and timely initiating signals which are to be supplied by the sensors, transmitters and logic components making up the various instrumentation channels of the Engineered Safety Features Actuation System.

7.3.1 DESCRIPTION

The Engineered Safety Features Actuation System uses selected plant parameters, determines whether or not predetermined safety limits are being exceeded and, if they are, combines the signals into logic matrices sensitive to combinations indicative of primary or secondary system boundary ruptures (Condition III or IV faults). Once the required logic combination is completed, the system sends actuation signals to the appropriate engineered safety features components. The Engineered Safety Features Actuation System meets the requirements of Criteria 13, 20, 27, 28, and 38 of the 1971 General Design Criteria (GDC).

7.3.1.1 System Description

The Engineered Safety Features Actuation System is a functionally defined system described in this section. The equipment which provides the actuation functions identified in Section 7.3.1.1.1 is listed below and discussed in this section and the references.

1. Process Instrumentation and Control System (Reference [1]).

2. Solid-State Logic Protection System (Reference [2]).

3. Engineered safety features test cabinet (Reference [3]).

4. Engineered safety features loading sequence control panels.

5. Manual actuation circuits.

The Engineered Safety Features Actuation System consists of 2 discrete portions of circuitry: 1) An analog portion consisting of 3 to 4 redundant channels per parameter or variable to monitor various plant parameters such as the Reactor Coolant System and steam system pressures, temperatures and flows and Reactor Building pressures; and

2) a digital portion consisting of 2 redundant logic trains which receive inputs from the analog protection channels and perform the logic needed to actuate the engineered safety features. Each digital train is capable of actuating the engineered safety features equipment required. The intent is that any single failure within the Engineered Safety Features Actuation System shall not prevent system action when required.

The redundant concept is applied to both the analog and logic portions of the system. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment penetrations and analog protection racks terminating at the redundant safeguards logic racks. The design meets the requirements of Criteria 20, 21, 22, 23, and 24 of the 1971 GDC.

The variables are sensed by the analog circuitry as discussed in Reference[1] and in Section 7.2. The outputs from the analog channels are combined into actuation logic as shown on Figure 7.2-1, Sheets 5, 6, 7, and 8. Tables 7.3-1 and 7.3-2 give additional information pertaining to logic and function.

The interlocks associated with the Engineered Safety Features Actuation System are outlined in Table 7.3-3. These interlocks satisfy the functional requirements discussed in Section 7.1.2.

Manual actuation from the control board of both trains of containment isolation Phase A is provided by operation of either one of the redundant momentary containment isolation Phase A controls. Also on the control board is manual actuation of safety injection by one of the redundant controls and a manual activation of containment isolation Phase B by either of 2 sets of controls. Each set consists of 2 switches which also actuate reactor building spray.

Manual controls are also provided to supplement the semi-automatic switchover from the injection to the recirculation phase after a loss of coolant accident.

7.3.1.1.1 Function Initiation

The specific functions which rely on the Engineered Safety Features Actuation System for initiation are:

1. A reactor trip, provided one has not already been generated by the Reactor Trip System.

2. Cold leg injection isolation valves which are opened for injection of borated water by charging pumps into the cold legs of the Reactor Coolant System.

3. Charging pumps and associated valving which provide emergency makeup water to the cold legs of the Reactor Coolant System following a loss of coolant accident.

4. Phase A containment isolation, whose function is to prevent fission product release. (Isolation of all lines not essential to reactor protection.)

5. Steam line isolation to prevent the continuous, uncontrolled blowdown of more than one steam generator and thereby uncontrolled Reactor Coolant System cooldown.

6. Main feedwater line isolation to prevent or mitigate the effect of excessive cooldown.

7. Start the emergency diesels to assure backup supply of power to emergency and supporting systems components.

8. Isolate the control room intake ducts to meet control room occupancy requirements following a loss of coolant accident.

9. Reactor building spray actuation which performs the following functions:

    a. Initiates reactor building spray to reduce reactor building pressure and temperature following a loss of coolant or steam line break accident inside the Reactor Building. Iodine removal benefits are also obtained from reactor building spray following a loss of coolant accident.

    b. Initiates Phase B containment isolation which isolates the Reactor Building following a loss of reactor coolant accident, or a steam or feedwater line break within the Reactor Building to limit radioactive releases. (Phase B isolation together with Phase A isolation results in isolation of all but engineered safety features lines penetrating the Reactor Building.)

10. Initiates the engineered safety features loading sequence (ESFLS) which provides timing in order to load the buses at predetermined intervals, avoiding overload conditions on the associated bus. In addition, the engineered safety features loading sequence provides for tripping and blocking of loads. The engineered safety features loading sequence initiates the following functions:

    a. Those pumps which serve as part of the heat sink for Reactor Building cooling (i.e., service water) and associated supporting systems, such as component cooling water pumps and chilled water pumps.

    b. Motor driven emergency feedwater pumps.

    c. Residual heat removal pumps.

    d. Reactor building cooling units (recirculation fans and filtration system) which cool the Reactor Building and limit the potential for release of fission products from the Reactor Building by reducing pressure following an accident.

e. Trip and lockout of non-engineered safety features loads.

7.3.1.1.2 Analog Circuitry

The process analog sensors and racks for the Engineered Safety Features Actuation System are covered in Reference[1]. Discussed in this report are the parameters to be measured including pressures, flows, tank and vessel water levels, and temperatures as well as the measurement and signal transmission considerations. These latter considerations include the transmitters, orifices and flow elements, resistance temperature detectors, as well as automatic calculations, signal conditioning and location and mounting of the devices.

The sensors monitoring the primary system are located as shown on the piping flow diagrams in Chapter 5. The secondary system sensor locations are shown on the steam system flow diagrams given in Chapter 10.

Reactor Building pressure is sensed by 4 physically separated differential pressure transmitters mounted and supported outside of the Reactor Building. These transmitters, meeting Class 1E seismic criteria regarding mounting, are connected to the Reactor Building atmosphere by a filled transmission system. The distance from penetration to transmitter is kept to a minimum, and separation is maintained. This arrangement, together with the pressure sensors external to the Reactor Building, meets the double barrier requirements of General Design Criteria-56 and Regulatory Guide 1.11.

Pumps and valves which are an integral part of, or associated with the engineered safeguards (used for injection, reactor building spray and recirculation) will have an operation/position status light.

Engineered safety features remote operated valves have position indication on the control board in 2 places to show proper positioning of the valves. Red and green indicator lights are located next to the manual control station showing open and closed positions. The engineered safety features (safety injection) positions of these valves are displayed by an energized bright light on the monitor light panels, which consist of an array of white lights which are dim when the valves are in their normal or required positions for power operations. The monitor lights for automatically actuated valves are energized when the valve is in the automatically actuated position. These monitor lights thus enable the operator to quickly assess the status of the Engineered Safety Features Systems. These indications are derived from contacts integral to the valve operators. The circuits for the engineered safety features monitor lights and red/green lights are classified as associated circuits and have electrical and physical separation. In the cases of the accumulator isolation valves, redundancy of position indication is provided by valve stem mounted limit switches which actuate annunciators on the control board when the valves are not correctly positioned for engineered safety features actuation.

The stem mounted switches for the accumulator isolation valves are independent of the limit switches in the motor operators.

7.3.1.1.3 Digital Circuitry

The engineered safety features logic racks are discussed in detail in Reference[2]. The description includes the considerations and provisions for physical and electrical separation as well as details of the circuitry. Reference[2] also covers certain aspects of online test provisions, provisions for test points, considerations for the instrument power source, considerations for accomplishing physical separation. The outputs from the analog channels are combined into actuation logic as shown on Sheets 5, 6, 7, 8, and 14 of Figure 7.2-1.

To facilitate engineered safety features actuation testing, 2 test cabinets (1 per train) are provided which enable operation, to the maximum practical extent, of safety features loads on a group by group basis until actuation of all devices has been checked (see Reference[3]). Final actuation testing is discussed in detail in Section 7.3.2. 99-01

Separation and redundancy requirements are satisfied for the engineered safety features loading sequence by the provision of 2 independent engineered safety features load sequencer control panels. These physically separate control panels, located in the relay room, each consist of a logic output relay cabinet.

7.3.1.1.4 Final Actuation Circuitry

The outputs of the Solid-State Logic Protection System (the slave relays) are energized to actuate. These devices are listed as follows:

1. Safety Injection System pump and valve actuators. See Chapter 6 for flow diagrams and additional information.

2. Containment isolation (Phase A - "T" signal isolates all nonessential process lines on receipt of safety injection signal; Phase B - "P" signal isolates remaining process lines (which do not include engineered safety features lines) on receipt of 2/4 Hi-3 containment pressure signal). For further information, see Section 6.2.4.

3. Diesel start (see Chapter 8).

4. Feedwater isolation (see Chapter 10).

5. Ventilation isolation valve and damper actuators (see Chapter 6).

6. Steam line isolation valve actuators (see Chapter 10).

7. Reactor Building spray pump and valve actuators (see Chapter 6).

8. Engineered safety features loading sequence (see Section 7.3.1.1.5).

If an accident is assumed to occur coincident with a loss of offsite power, the engineered safety features loads must be sequenced onto the diesel generators to prevent overloading them. This sequence is discussed in Chapter 8. The design meets the requirements of Criterion 35 of the 1971 General Design Criteria.

7.3.1.1.5 Engineered Safety Features Loading Sequence Control Panels

The ESFLS automatically loads engineered safety features components to the ESF buses under the following conditions:

a. Loss of offsite power or degradation of voltage.

b. Safety injection.

c. Safety injection coincident with loss of offsite power or degradation of voltage.

The loss of offsite power or degradation of voltage considered here is related to the engineered safety features buses (7.2 V buses 1DA and/or 1DB). Loss of voltage is 00-01 detected on either bus by 3/3 loss of voltage relays. Degraded voltage is detected on either bus by 3/3 degraded voltage relays. The safety injection signal is generated by the Solid-State Protection System. To assure component operation under the various initiating conditions, 2 initiating sequences are provided. These sequences are a "blackout sequence," which loads the components needed to shut down the plant in the event of a loss of power or degraded voltage, and a "safety injection sequence," which loads the components needed to mitigate the consequences of design bases accidents occurring coincident with a loss of offsite power or degradation of voltage.

The initiation of engineered safety features loads following safety injection with engineered safety features bus power available utilizes the same "safety injection sequence" identified above. Use of the loading sequencer during conditions when ESF bus power is available provides the following benefits:

1. Enhanced reliability due to a simplified logic for component actuation.

2. Improved online testing capability.

As discussed in Section 8.3, each 7.2 kV engineered safety features bus is fed from 00-01 both the normal (offsite) and emergency (onsite) supplies and each engineered safety features bus is provided with loss of voltage and degraded voltage relays. This arrangement enables operation of the engineered safety features logic sequence independent of the source (offsite or onsite) of power.

When initiated, the sequencer provides timing to load the buses at 5 second intervals. Order of loading is determined by system requirements, design capabilities of the diesel

and the type of incident or accident, as evaluated by the engineered safety features logic sequence logic circuitry (see Figure 7.3-1 and Section 8.3). In addition, the sequencer provides for tripping and blocking of loads. The engineered safety features logic sequence is located in the relay room and indication is provided on the main control board. It provides the operator with information on the progress of the loading sequence and consists of internal logic circuits and output relays (the relays are located in a cabinet in the relay room). The output of these relays actuates the required safety-related equipment.

Each engineered safety features loading sequence consists of the following components:

1. Logic circuits, located in the logic section of the control cabinet.

2. Indication, located on the monitor section of the control cabinet and on section XCP-6117 of the main control board. The indication on the main control board provides the operator with information necessary for evaluation of progress of the loading sequence.

3. Output relays, located in the relay cabinet, to provide multiple contacts for the various functions.

7.3.1.1.6 Support Systems

The following systems are required for support of the engineered safety features:

1. Service Water - Heat Removal (see Chapter 9).

2. Component Cooling Water Systems - Heat Removal (see Chapter 9).

3. Chilled Water System - Heat Removal (see Chapter 9).

4. Class 1E Electrical Power Distribution Systems (see Chapter 8).

5. Other Heating, Ventilating and Air Conditioning Systems (see Section 9.4.5).

7.3.1.2 <u>Design Bases Information</u>

The functional diagrams presented in Figure 7.2-1, Sheets 5, 6, 7, and 8 provide a graphic outline of the functional logic associated with requirements for the Engineered Safety Features Actuation System. Requirements for the Engineered Safety Features System are given in Chapter 6. Given below is the design bases information required in IEEE Standard 279-1971, Reference[4].

7.3.1.2.1 Generating Station Conditions

The following is a summary of those generating station conditions requiring protective action:

1. Primary System

   a. Rupture in small pipes or cracks in large pipes.

   b. Rupture of a reactor coolant pipe (loss of coolant accident).

   c. Steam generator tube rupture.

2. Secondary System

   a. Minor secondary system pipe breaks resulting in steam release rates equivalent to a single dump, relief, or safety valve.

   b. Rupture of a major steam pipe.

7.3.1.2.2 Generating Station Variables

The following list summarizes the generating station variables required to be monitored for the automatic initiation of safety injection during each accident identified in the preceding section. Post accident monitoring requirements are described in the VCSNS Environmental Qualification/Reg. Guide 1.97 Design Basis Document.

1. Primary System Accidents

   a. Pressurizer pressure.

   b. Reactor Building pressure (not required for steam generator tube rupture).

2. Secondary System Accidents

   a. Pressurizer pressure.

   b. Steam line pressures.

   c. Reactor Building pressure (steam or feedwater line break inside reactor building).

   d. Steam line differential pressure.

7.3.1.2.3 Spatially Dependent Variables

The only variable sensed by the Engineered Safety Features Actuation System which has spatial dependence is reactor coolant temperature. The effect on the measurement is negated by taking multiple samples from the reactor coolant hot leg and averaging these samples by mixing in the resistance temperature detector bypass loop.

7.3.1.2.4 Limits, Margins, and Levels

Prudent operational limits, available margins, and setpoints before onset of unsafe conditions requiring protective action are discussed in Chapter 15 and the Technical Specifications. 00-01

7.3.1.2.5 Abnormal Events

The malfunctions, accidents, or other unusual events which could physically damage protection system components or could cause environmental changes are as follows:

1. Loss of coolant accident (see Sections 15.3 and 15.4).

2. Steam line breaks (see Sections 15.3 and 15.4).

3. Earthquakes (see Chapters 2 and 3).

4. Fire (see Section 9.5.1).

5. Explosion (Hydrogen buildup inside the Reactor Building) (see Section 15.4).

6. Missiles (see Section 3.5).

7. Flood (see Chapters 2 and 3).

7.3.1.2.6 Minimum Performance Requirements

Minimum performance requirements are as follows:

1. System Response Times

   The Engineered Safety Features Actuation System response time is defined as the interval required for the engineered safety features sequence to be initiated subsequent to the point in time that the appropriate variable(s) exceed setpoints. The response time includes sensor/process (analog) and logic (digital) delay plus, the time delay associated with tripping open the reactor trip breakers and control and latching mechanisms. The values listed herein are maximum allowable times consistent with the safety analyses and are systematically verified during plant

preoperational startup tests. These maximum delay times thus include all compensation and therefore require that any such network be aligned and operating during verification testing.

The Engineered Safety Features Actuation System is always capable of having response time tests performed using the same methods as those tests performed during the preoperational test program or following significant component changes.

System response times for loss of coolant protection are: 00-01

a. Pressurizer pressure 1.0 second

b. Reactor building pressure 1.5 seconds

Maximum allowable time delays in generating the actuation signal for steam break protection are given in Table 7.3-4.

2. System Accuracies

Accuracies required for generating the required actuation signals for loss of coolant protection are given in Table 7.3-5.

3. Ranges of sensed variables to be accommodated until conclusion of protective action is assured are given in Table 7.3-5.

7.3.1.3 Final System Drawings

The schematic diagrams for the systems discussed in this section are discussed in Section 1.7.

7.3.2 ANALYSIS

7.3.2.1 Failure Mode and Effects Analyses

Failure mode and effects analyses have been performed on Engineered Safety Features Systems (ESFS) equipment within the scope of Westinghouse. The results verify that these systems meet protection single failure criteria as required by IEEE Standard 279-1971 and the Virgil C. Summer Nuclear Station (Engineered Safety Features Systems) equipment is designed to equivalent safety design criteria. The actuation of the Virgil C. Summer Nuclear Station Engineered Safety Features Systems is functionally the same as the systems studied in these analyses.

The failure mode and effects analysis (FMEA) which was performed on engineered safety features engineered safety features equipment within the scope of Westinghouse was for a typical Westinghouse Engineered Safety Features Actuation System (ESFAS). (See Reference [5]). The analysis has generic application to all Westinghouse Engineered Safety Features Actuation Systems of the Virgil C. Summer

Nuclear Station vintage. The conclusion is that the analysis (1) qualitatively demonstrates the reliability of the Engineered Safety Features Actuation System to perform its intended function and (2) shows that the Engineered Safety Features Actuation System does comply with the single failure criterion, because no single failure was found which could prevent the Engineered Safety Features Actuation System from generating the proper actuation signal on demand for an engineered safety feature. Random single failures are either in a safe direction or a redundant channel or train ensures the necessary actuation capability.

The basis of a failure mode and effects analysis is principally that single failures are detectable, identifiable, and random. They are not systematic (common mode). The systematic failure considerations applied to equipment hardware, as well as actuation functions, are addressed elsewhere in the final safety analysis report, such as:

1. Seismic qualification of Seismic Category 1 instrumentation and electrical equipment (Section 3.10). This conforms to Section 4.7.4.2 of IEEE 279-1971.

2. Environmental design of mechanical and electrical equipment (Section 3.11). This conforms to Section 4.7.4.2 of IEEE 279-1971.

3. The Nuclear Instrumentation System, the Solid State Protection System, and the 7300 Series Process Control System noise tests (See Section 7.2.2.2.3.7 and Reference 5 in Section 7.2.4).

4. Manual initiation of protective actions (See Section 7.3.2.2.7).

7.3.2.2 Compliance With Standards and Design Criteria

Discussion of the General Design Criteria (GDC) is provided in various sections of Chapter 7 where a particular General Design Criteria is applicable. Applicable General Design Criteria include Criteria 13, 20, 21, 22, 23, 24, 25, 27, 28, 35, 37, 38, 40, 43, and 46 of the 1971 General Design Criteria. Compliance with certain IEEE Standards is presented in Sections 7.1.2.7, 7.1.2.9, 7.1.2.10, and 7.1.2.11. The discussion given 00-01
below shows that the Engineered Safety Features Actuation System complies with IEEE Standard 279-1971, Reference[4]. For the list of references to the discussions of conformance to applicable criteria, see Table 7.1-1.

Table 7.3-6 outlines the degree of conformance of the engineered safety features loading sequence control panels to Regulatory Guide 1.53 and IEEE Standard 379-1972, Reference[5].

7.3.2.2.1 Single Failure Criteria

The discussion presented in Section 7.2.2.2.3 is applicable to the Engineered Safety Features Actuation System, with the following exception.

In the engineered safety features, a loss of instrument power will call for actuation of engineered safety features equipment controlled by the specific bistable that lost power (Reactor Building spray excepted). The actuated equipment must have power to comply. The power supply for the protection systems is discussed in Section 7.6 and in Chapter 8. For Reactor Building spray, the final bistables are energized to trip to avoid spurious actuation. In addition, manual Reactor Building spray requires a simultaneous actuation of 2 manual controls. This is considered acceptable because spray actuation on Hi-3 Reactor Building pressure signal provides automatic initiation of the system via protection channels meeting the criteria in Reference [4]. Moreover, 2 sets (2 switches per set) of Reactor Building spray manual initiation switches are provided to meet the requirements of IEEE Standard 279-1971. Also it is possible for all engineered safety features equipment (valves, pumps, etc.) to be individually manually actuated from the control board. Hence, a third mode of Reactor Building spray initiation is available. The design meets the requirements of Criteria 21 and 23 of the 1971 General Design Criteria.

7.3.2.2.2 Equipment Qualification

Equipment qualifications are discussed in Sections 3.10 and 3.11.

7.3.2.2.3 Channel Independence

The discussion presented in Section 7.2.2.2.3 is applicable. The engineered safety features slave relay outputs from the solid-state logic protection cabinets are redundant, and the actuations associated with each train are energized up to and including the final actuators by the separate a-c power supplies which power the logic trains.

7.3.2.2.4 Control and Protection System Interaction

The discussions presented in Section 7.2.2.2.3 are applicable.

7.3.2.2.5 Capability for Sensor Checks and Equipment Test and Calibration

The discussions of system testability in Section 7.2.2.2.3 are applicable to the sensors, analog circuitry, and logic trains of the Engineered Safety Features Actuation System.

The following discussions cover those areas in which the testing provisions differ from those for the Reactor Trip System.

7.3.2.2.5.1 Testing of Engineered Safety Features Actuation Systems

The Engineered Safety Features Systems are tested to provide assurance that the systems will operate as designed and will be available to function properly in the unlikely event of an accident. The testing program meets the requirements of Criteria 21, 37, 40, and 43 of the 1971 General Design Criteria and requirements on testing of the Emergency Core Cooling System as stated in General Design Criteria-37 except for the operation of those components that will cause an adverse effect to the safety or operability of the plant per Regulatory Guide 1.22 as discussed in Section 7.1.2.5. The tests described in Section 7.2.2.2.3 and further discussed in Section 6.3.4 meet the actual safety injection. The test, as described, demonstrates the performance of the full operational sequence that brings the system into operation, the transfer between normal and emergency power sources and the operation of associated cooling water systems. The charging pumps and residual heat removal pumps are started and operated and their performance verified in a separate test discussed in Section 6.3.4. When the pump tests are considered in conjunction with the Emergency Core Cooling System test, the requirements of General Design Criteria-37 on testing of the Emergency Core Cooling System are met as close as possible without causing an actual safety injection. 99-01

Testing as described in Sections 6.3.4, 7.2.2.2.3, and 7.3.2.2.5 provides complete periodic testability during reactor operation of all logic and components associated with the Emergency Core Cooling System.

This design meets the requirements of Regulatory Guide 1.22 as discussed in the above sections. The program is as follows:

1. Prior to initial plant operations, Engineered Safety Features System tests will be conducted.

2. Subsequent to initial startup, Engineered Safety Features System tests will be conducted during each regularly scheduled refueling outage.

3. During online operation of the reactor, engineered safety features analog and logic circuitry will be fully tested. In addition, essentially all of the engineered safety features final actuators will be fully tested. The remaining few final actuators whose operation is not compatible with continued online plant operation will be checked by means of continuity testing.

7.3.2.2.5.2 Performance Test Acceptability Standard for the "S" (Safety Injection Signal) and for the "P" (the Automatic Demand Signal for Reactor Building Spray Actuation) Actuation Signals Generation

During reactor operation the basis for Engineered Safety Features Actuation Systems acceptability will be the successful completion of the overlapping tests performed on the initiating system and the Engineered Safety Features Actuation System, see Figure 7.3-2. Checks of process indications verify operability of the sensors. Analog checks and tests verify the operability of the analog circuitry from the input of these circuits through to and including the logic input relays except for the input relays associated with the Reactor Building spray function which are tested during the solid-state logic testing. Solid-State logic testing also checks the digital signal path from and including logic input relay contacts through the logic matrices and master relays and performs continuity tests on the coils of the output slave relays; final actuator testing operates the output slave relays and verifies operability of those devices which require safeguards actuation and which can be tested without causing plant upset. A continuity check is performed on the actuators of the untestable devices. Operation of the final devices is confirmed by control board indication and visual observation that the appropriate pump breakers close and automatic valves shall have completed their travel.

The basis for acceptability for the engineered safety features interlocks will be control board indication of proper receipt of the signal upon introducing the required input at the appropriate setpoint.

Routine periodic inspections of the ESF equipment and performance acceptability testing of the "S" (Safety Injection Signal) and of the "P" (Automatic Demand Signal for Reactor Building Spray Actuation) are consistent with inspections and tests of the NSSS Electrical Equipment Section 3.11.2.2.1 and the Technical Specifications. 00-01

7.3.2.2.5.3 Frequency of Performance of Engineered Safety Features Actuation Tests

During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed on a periodic basis. Testing, including the sensors, is also performed during scheduled plant shutdown for refueling.

7.3.2.2.5.4 Engineered Safety Features Actuation Test Description

The following sections describe the testing circuitry and procedures for the online portion of the testing program. The guidelines used in developing the circuitry and procedures are:

1. The test procedures must not involve the potential for damage to any plant equipment.

2. The test procedures must minimize the potential for accidental tripping.

3. The provisions for online testing must minimize complication of engineered safety features actuation circuits so that their reliability is not degraded.

7.3.2.2.5.5 Description of Initiation Circuitry

Several systems comprise the total Engineered Safety Features System, the majority of which may be initiated by different process conditions and be reset independently of each other.

The remaining functions (listed in Section 7.3.1.1.1) are initiated by a common signal (safety injection) which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as Emergency Feedwater, Component Cooling Water, Service Water, and Heating, Ventilating and Air Conditioning Systems listed in Section 9.4.5, is initiated by the safety injection signal.

Each function is actuated by a logic circuit which is duplicated for each of the 2 redundant trains of engineered safety features initiation circuits.

The output of each of the initiation circuits consists of a master relay which drives slave relays for contact multiplication as required. The logic, master, and slave relays are mounted in the solid-state logic protection cabinets designated Train A, and Train B, respectively, for the redundant counterparts. The master and slave relay circuits operate various pump and fan circuit breakers or starters, motor operated valve contactors, solenoid operated valves, emergency generator starting, etc.

7.3.2.2.5.6 Analog Testing

Analog testing is identical to that used for reactor trip circuitry and is described in Section 7.2.2.2.3.

An exception to this is Reactor Building spray, which is energized to actuate 2/4 and reverts to 2/3 when 1 channel is in test.

7.3.2.2.5.7 Solid-State Logic Testing

Except for Reactor Building spray channels; solid-state logic testing is the same as that discussed in Section 7.2.2.2.3. During logic testing of 1 train, the other train can initiate the required engineered safety features function. For additional details, see Reference[2].

7.3.2.2.5.8 Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. Slave relays (K601, K602, etc.) do not operate because of reduced voltage.

The Engineered Safety Features Actuation System final actuation device or actuated equipment testing shall be performed from the engineered safety features test cabinets. These cabinets are normally located near the Solid-State Logic Protection System equipment. There is 1 test cabinet provided for each of the 2 protection Trains "A" and "B". Each cabinet contains individual test switches necessary to actuate the slave relays. To prevent accidental actuation, test switches are of the type that must be rotated and then depressed to operate the slave relays. Assignments of contacts of the slave relays for actuation of various final devices or actuators have been made such that groups of devices or actuated equipment, can be operated individually during plant operation without causing plant upset or equipment damage. In the unlikely event that a safety injection signal is initiated during the test of the final device that is actuated by this test, the device will already be in its engineered safety feature position. 99-01

During this last procedure, close communication between the Control Room operator and the operator at the test panel is required. Prior to the energizing of a slave relay, the operator in the Control Room assures that plant conditions will permit operation of the equipment that will be actuated by the relay. After the tester has energized the slave relay, the Control Room operator observes that all equipment has operated as indicated by appropriate indicating lamps, monitor lamps and annunciators on the control board and, using a prepared check list, records all operations. After proper operation is verified, the test switch is reset at the test panel and each device is returned to its desired mode from the control board.

By means of the procedures outlined above, all engineered safety features devices actuated by engineered safety features actuation systems initiation circuits, with the exceptions noted in Section 7.1.2.5 under a discussion of Regulatory Guide 1.22 are operated by the automatic circuitry.

7.3.2.2.5.9 Actuator Blocking and Continuity Test Circuits

Those few final actuation devices that cannot be designed to be actuated during plant operation (discussed in Section 7.1.2.5) have been assigned to slave relays for which additional test circuitry has been provided to individually block actuation of a final device upon operation of the associated slave relay during testing. Operation of these slave relays, including contact operations, and continuity of the electrical circuits associated with the final devices' control are checked in lieu of actual operation. The circuits provide for monitoring of the slave relay contacts, the devices' control circuit cabling, control voltage and the devices' actuation relay coils, solenoids, etc. Interlocking prevents blocking the output from more than 1 output relay in a protection train at a

time. Interlocking between trains is also provided to prevent continuity testing in both trains simultaneously, therefore the redundant device associated with the protection train not under test will be available in the event protection action is required. If an accident occurs during testing, the automatic actuation circuitry will override testing as noted above. One (1) exception to this is that if the accident occurs while testing a slave relay whose output must be blocked, those few final actuation devices associated with this slave relay will not be overridden; however, the redundant devices in the other train would be operational and would perform the required safety function. Actuation devices to be blocked are identified in Section 7.1.2.5.

The continuity test circuits for these components that cannot be actuated online are verified by proving lights on the engineered safety features test racks.

The typical schemes for blocking operation of selected engineered safety features function actuator circuits are shown in Figure 7.3-3 as details A and B. The schemes operate as explained below and are duplicated for each engineered safety features train.

Detail A shows the circuit for contact closure for protection function actuation. Under normal plant operation, and equipment not under test, the test lamps "DS *" for the various circuits will be energized. Typical circuit path will be through the normally closed test relay contact "K8 *" and through test lamp connections 1 to 3. Coils "X1" and "X2" will be capable of being energized for protection function actuation upon closure of solid-state logic output relay contacts "K *". Coil "X1" or "X2" is typical for a breaker closing auxiliary coil, motor starter master coil, coil of a solenoid valve, auxiliary relay, etc. When the contacts "K8 *" are opened to block energizing of coil "X1" and "X2", the white lamp is de-energized, and the slave relay "K *" may be energized to perform continuity testing. To verify operability of the blocking relay in both blocking and restoring normal service, open the blocking relay contact in series with lamp connections - the test lamp should be de-energized; close the blocking relay contact in series with the lamp connections - the test lamp should now be energized, which verifies that the circuit is now in its normal, i.e., operable condition.

Detail B shows the circuit for contact opening for protection function actuation. Under normal plant operation, and equipment not under test, and white test lamps "DS *" for the various circuits will be energized, and green test lamp "DS *" will be de-energized. Typical circuit path for white lamp "DS *" will be through the normally closed solid-state logic output relay contact "K *" and through test lamp connections 1 to 3. Coils "Y1" and "Y2" will be capable of being de-energized for protection function actuation upon opening of solid-state logic output relay contacts "K *". Coil "Y2" is typical for a solenoid valve coil, auxiliary relay, etc. When the contacts "K8 *" are closed to block de-energizing of coils "Y1" and "Y2", the green test lamp is energized, and the slave relay "K *" may be energized to verify operation (opening of its contacts). To verify operability of the blocking relay in both blocking and restoring normal service, close the blocking relay contact to the green lamp - the green test lamp should now be energized

also; open this blocking relay contact - the green test lamp should be de-energized, which verifies that the circuit is now in its normal, i.e., operable condition.

7.3.2.2.5.10

The testing provisions of the engineered safety features loading sequence control panels differ from the Engineered Safety Features Actuation System. Each engineered safety features loading sequence control panel is designed to combine automatic testing with manual testing. Continuous and periodic test features are provided to test for equipment faults (e.g., open circuits, short circuits, inoperative timers). All system accuracy and functional requirements are maintained when automatic testing is implemented. These features are provided in accordance with IEEE-420, Section 4.7 and the following:

1. Automatic Test

   The Automatic Test Feature has 3 operating modes: Continuous, Fast, and Slow. During these modes, the Automatic Test Feature monitors the engineered safety features loading sequence and upon occurrence of an improper response will display the step number of the failed test and energize a fault relay for remote annunciator. The Continuous mode provides on-line surveillance of the engineered safety features loading sequence operation by repeatedly cycling the Automatic Test circuits through their test states and monitoring the various system outputs for appropriate responses. Operation is check from the logic input signals through the logic and counter stages and up to and including the relay driven outputs. The surveillance will not interface with system requirements nor cause an undesired relay actuation during normal system operation. The Fast mode operates in the same manner as the Continuous mode except that only 1 test cycle is performed for each operation initiated test.

   The Slow mode allows manual stepping of the Automatic Test circuits through a test cycle to observe the system response via the cabinet control panel indicators. Operation is checked from the logic input signals through the logic and counter stages, the relay driver outputs, and output relays. The Slow mode actuates the output relays thereby starting or tripping plant equipment.

   Fault detection and annunciation, local and remote, are automatic in the Continuous and Fast mode while operation interpretation of the system response is required in the Slow mode. Additionally, automatic resetting of the Automatic Test circuits, in response to a True input signal, is provided in the Continuous and Fast modes. Manual reset is required in the Slow mode.

2. Manual Test

The Manual Test Features provide the means to verify all engineered safety features loading sequence functions locally at the cabinet control panel. Input test switches enable simulation of all inputs, including operation of the input buffer relays, in any combination or time sequence. Output test switches enable actuation of each step or output individually, including operating of the final associated solid state driver stage. Blocking switches, which allow active testing of Output 1 and Output 4 without effecting associated external loads, are also provided. Indicator lamps associated with each input, system, startup, each step and each output allow the operation to visually observe the results of all tests.

7.3.2.2.5.11 Time Required for Testing

It is estimated that analog testing can be performed at a rate of several channels per hour. Logic testing of both Trains A and B can be performed in less than 30 minutes. Testing of actuated components (including those which can only be partially tested) will be a function of control room operator availability. It is expected to require several shifts to accomplish these tests. During this procedure automatic actuation circuitry will override testing, except for those few devices associated with a single slave relay whose outputs must be blocked and then only while blocked. It is anticipated that continuity testing associated with a blocked slave relay could take several minutes. During this time the redundant devices in the other train would be functional.

7.3.2.2.5.12 Summary of Online Testing Capabilities

The procedures described provide capability for checking completely from the process signal to the logic cabinets and from there to the individual pump and fan circuit breakers or starters, valve contactors, pilot solenoid valves, etc., including all field cabling actually used in the circuitry called upon to operate for an accident condition. For those few devices whose operation could adversely affect plant or equipment operation, the same procedure provides for checking from the process signal to the logic rack. To check the final actuation device, a continuity test of the individual control circuits is performed.

The procedures require testing at various locations.

1. Analog testing and verification of bistable setpoint are accomplished at process analog racks. Verification of bistable relay operation is done at the control board status lights.

2. Logic testing through operation of the master relays and low voltage application to slave relays is done at the logic rack test panel.

3. Testing of pumps, fans and valves is done at a test panel located in the vicinity of the logic racks in combination with the control room operator.

4. Continuity testing from those circuits that cannot be operated is done at the same test panel mentioned in item 3 above.

The reactor coolant pump essential service isolation valves consist of the isolation valves on the component cooling water and the seal water return header.

The main reason for not testing these valves periodically is that the reactor coolant pumps may be damaged. Although pump damage from this type of test would not result in a situation which endangers the health and safety of the public, it could result in unnecessary shutdown of the reactor for an extended period of time while the reactor coolant pump or certain of its parts were replaced. This would place a great economic burden on South Carolina Electric and Gas Company.

Reactor Building Spray System pump tests will be performed periodically. The pump tests will be performed with the isolation valves in the spray pump discharge lines at the Reactor Building blocked closed; the Sodium Hydroxide Storage Tank valves are also blocked closed.

7.3.2.2.5.13 Testing During Shutdown

Emergency Core Cooling System tests will be performed at each major fuel reloading with the Reactor Coolant System isolated from the Emergency Core Cooling System by closing the appropriate valves. A test safety injection signal will then be applied to initiate operation of active components (pumps and valves) of the Emergency Core Cooling System. This is in compliance with Criterion 37 of the 1971 General Design Criteria.

7.3.2.2.5.14 Periodic Maintenance Inspection

The maintenance procedures which follow may be accomplished in any order. The frequency will depend on the operating conditions and requirements of the reactor power plant. If any degradation of equipment operation is noted, either mechanically or electrically, remedial action is taken to repair, replace, or readjust the equipment.

Typical maintenance procedures include the following:

1. Check cleanliness of all exterior and interior surfaces.

2. Inspect for loose or broken control knobs and burned-out indicator lamps.

3. Inspect for moisture and condition of cables and wiring.

4. Visually or mechanically check connectors and terminal boards for looseness, poor connection, or corrosion.

5. Inspect the components of each assembly for signs of overheating or component deterioration.

6. Perform complete system operating check.

The balance of the requirements listed in Reference[4] (paragraphs 4.11 through 4.22) are discussed in Section 7.2.2.2.3. Paragraph 4.20 receives special attention in Section 7.5.4. 00-01

7.3.2.2.6 Manual Resets and Blocking Features

The manual reset feature associated with reactor building spray actuation is provided in the standard design of the Westinghouse Solid-State Protection System design for 2 basic purposes: First, the feature permits the operator to start an interruption procedure of automatic reactor building spray in the event of false initiation of an actuation signal. Second, although spray system performance is automatic, the reset feature enables the operator to start a manual takeover of the system to handle unexpected events which can be better dealt with by operator appraisal of changing conditions following an accident.

It is most important to note that manual control of the Spray System does not occur, once actuation has begun, by just resetting the associated log devices alone. Components will seal in (latch) so that removal of the actuation signal, in itself, will neither cancel or prevent completion of protective action or provide the operator with manual override of the automatic system by this single action. In order to take complete control of the system to interrupt its automatic performance, the operator must deliberately unlatch relays which have "sealed in" the initial actuation signals in the associated motor control center, in addition to tripping the pump motor circuit breakers, if stopping the pumps is desirable or necessary.

The manual reset feature associated with reactor building spray, therefore, does not perform a bypass function. It is merely the first of several manual operations required to take control from the automatic system or interrupt its completion should such an action be considered necessary.

In event that the operator anticipates system actuation and erroneously concludes that it is undesirable or unnecessary and imposes a standing reset condition in 1 train (by operating and holding the corresponding reset switch at the time the initiate signal is transmitted) the other train will automatically carry the protective action to completion. In the event that the reset condition is imposed simultaneously in both trains at the time the initiate signals are generated, the automatic sequential completion of system action is interrupted and control has been taken by the operator. Manual takeover will be maintained, even though the reset switches are released, if the original initiate signal

exists. Should the initiate signal then clear and return again, automatic system actuation will repeat.

Note also that any time delays imposed on the system action are to be applied after the initiating signals are latched. Delay of actuation signals for fluid systems lineup, load sequencing, etc., does not provide the operator time to interrupt automatic completion, with manual reset alone, as would be the case if time delay were imposed prior to sealing of the initial actuation signal.

The manual block features associated with pressurizer and steam line safety injection signals provide the operator with the means to block initiation of safety injection during plant startup. These block features meet the requirements of paragraph 4.12 of IEEE Standard 279-1971 in that automatic removal of the block occurs when plant conditions require the protection system to be functional.

Safety injection actuation on low pressurizer pressure may be manually blocked when the primary pressure falls below the P-11 setpoint. Safety injection and steamline isolation actuation on low steamline pressure may also be manually blocked below the P-12 setpoint (low-low T_{avg}). Safety injection cannot be blocked on high steam line differential pressure or high-1 containment pressure, and steam line isolation cannot be blocked on either high steam line flow coincident with low-low T_{avg} or high-2 containment pressure. Thus these signals would always be available to automatically terminate a steam line rupture during cooldown or startup.

Furthermore, during heatup and cooldown and while safety injection is blocked, the operator will be in full manual control of the plant. He will be cognizant of the plant operating conditions and the expected changes in these parameters. If a serious steam line break should occur during this time, it should be apparent to the operator so that he can take the necessary action to prevent any adverse consequences in a timely fashion.

The types of instrumentation available to the operator which would indicate that a steam line break has occurred consists of alarms and indicated values. Alarms could occur on high steam flow, low steam line pressure (SI actuation, Steamline Isolation), low-low steam generator level (reactor trip), low steam generator level, high steam line differential pressure (SI actuation), high source range nuclear flux (reactor trip), and containment pressure high-1 (SI actuation) and high-2 (steam line isolation). 00-01

The instrumentation which would be indicated on the control board consists of the above channels plus T_{avg}, pressurizer level and pressurizer pressure. Since the shutdown margin during cooldown or startup is greater than that for the case analyzed in the FSAR, there will be more time for manual action to terminate the transient. Furthermore, the steam line pressure during cooldown and startup would be such that the consequences of the steam generator blowdown would be less severe than for the hot zero power case analyzed in the Final Safety Analysis Report.

Therefore, either the protection system will automatically terminate the transient or the operator will determine soon after the incident begins that a break has occurred and will take the necessary action.

7.3.2.2.7 Manual Initiation of Protective Actions (Regulatory Guide 1.62)

There are 3 individual main steam isolation valve momentary control switches (1 per loop) mounted on the control board. Each switch when actuated, will isolate its main steam line. In addition, an independent momentary control switch, mounted on the control board, will isolate all 3 main steam lines when actuated.

Manual initiation of semi-automatic switchover to recirculation following a loss of primary coolant accident is in compliance with paragraph 4.17 of IEEE Standard 279-1971 with the following comments:

1. The manual operations that are involved in this switchover are described in Section 6.3.

2. Once safety injection is initiated following a loss of primary coolant accident, the Reactor Building sump isolation valves in the Residual Heat Removal System pump suction lines will open automatically upon receipt of a lo-lo level signal from the refueling water storage tank level instrumentation.

3. Manual initiation of either 1 of 2 redundant safety injection actuation main control board mounted switches not only provides for actuation of the components required for reactor protection and mitigation of adverse consequences of the postulated accident prior to the recirculation mode associated with a loss of primary coolant accident, but also enables the Reactor Building sump isolation valves to automatically open when the lo-lo level setpoint on the refueling water storage tank is reached.

Manual operation of other components or manual verification of proper position as part of emergency procedures is not precluded nor otherwise in conflict with the above described compliance to paragraph 4.17 of IEEE Standard 279-1971.

No exception to the requirements of IEEE Standard 279-1971 has been taken in the manual initiation circuit of safety injection. Although paragraph 4.17 of IEEE Standard 279-1971 requires that a single failure within common portions of the protective system shall not defeat the protective action by manual or automatic means, the standard does not specifically preclude the sharing of initiated circuitry logic between automatic and manual functions. It is true that the manual safety injection initiation functions associated with 1 actuation train (e.g., Train A) shares portions of the automatic initiation circuitry logic of the same logic train; however, a single failure in shared functions does not defeat the protective action of the redundant actuation train (e.g., Train B). A single failure in shared functions does not defeat the protective action of the safety functions. It is further noted that the sharing of the logic by manual and

automatic initiation is consistent with the system level action requirements of IEEE Standard 279-1971, paragraph 4.17 and consistent with the minimization of complexity.

7.3.2.3 Further Considerations

In addition to the considerations given above, a loss of instrument air or loss of component cooling water to vital equipment has been considered. Neither the loss of instrument air nor the loss of component cooling water (assuming no other accident conditions) can cause safety limits as given in the Technical Specifications to be exceeded. Likewise, loss of either 1 of the 2 will not adversely affect the core or the Reactor Coolant System nor will it prevent an orderly shutdown if this is necessary. Furthermore, all pneumatically operated valves and controls will assume a preferred operating position upon loss of instrument air. It is also noted that, for conservatism during the accident analyses (Chapter 15), credit is not taken for the instrument air systems nor for any control system benefit. 00-01

In its present design, Westinghouse does not provide any circuitry which will directly trip the reactor coolant pumps on a loss of component cooling water. Normally, indication in the control room is provided whenever component cooling water is lost. The reactor coolant pumps can run about 10 minutes after a loss of component cooling water. This provides adequate time for the operator to correct the problem or trip the plant if necessary.

In regards to the Emergency Feedwater System, there are 2 motor driven pumps and one turbine driven pump. The motor driven pumps are initiated automatically by the following signals:

1. Safety injection, through the engineered safety features load sequencer.

2. Low-low level (2/3) in any steam generator (derived from the Solid-State Protection System output cabinets).

3. Manual start.

4. Trip of all main feed pumps.

5. Undervoltage on the diesel bus.

The turbine driven pump as well as the closing of blowdown and sample valves are initiated automatically by:

1. Low-low level (2/3) in 2/3 steam generators (derived from the Solid-State Protection System output cabinets).

2. Manual start.

3. Undervoltage on both diesel buses.

To assure auto-start of the component cooling water and service water pumps on the inactive loop and to prevent diesel generator overloading on a SI/LOOP signal, the circuit breaker(s) for the out of service or spare pump/chiller for systems with swing components will be racked out.

7.3.2.4 Summary

The effectiveness of the Engineered Safety Features Actuation System is evaluated in Chapter 15, based on the ability of the system to contain the effects of Condition III and IV faults, including loss of reactor coolant and steam break accidents. The Engineered Safety Features Actuation System parameters are based upon the component performance specifications which are given by the manufacturer or verified by test for each component. Appropriate factors to account for uncertainties in the data are factored into the constants characterizing the system.

The Engineered Safety Features Actuation System must detect Condition III and IV faults and generate signals which actuate the engineered safety features. The system must sense the accident condition and generate the signal actuating the protection function reliably and within a time determined by and consistent with the accident analyses in Chapter 15.

Much longer times are associated with the actuation of the mechanical and fluid system equipment associated with engineered safety features. This includes the time required for switching, bringing pumps and other equipment to speed and the time required for them to take load.

Operating procedures require that the complete Engineered Safety Features Actuation System normally be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the tripped mode, or bypass mode in the case of Reactor Building spray.

7.3.2.4.1 Loss of Coolant Protection

By analysis of loss of coolant accident and in system tests it has been verified that (except for very small coolant system breaks, which can be protected against by the charging pumps followed by an orderly shutdown), the effects of various loss of coolant accidents are reliably detected by the low pressurizer pressure signal.

For large coolant system breaks the passive accumulators inject first, because of the rapid pressure drop. This protects the reactor during the unavoidable delay associated with actuating the active Emergency Core Cooling System phase.

High Reactor Building pressure also actuates the Emergency Core Cooling System. Therefore, emergency core cooling actuation can be brought about by sensing this other direct consequence of a primary system break; that is the Engineered Safety Features Actuation System detects the leakage of the coolant into the Reactor Building. The generation time of the actuation signal of about 1.5 seconds, after detection of the consequences of the accident, is adequate.

Reactor Building spray will provide additional emergency cooling of the Reactor Building and also limit fission product release upon sensing elevated Reactor Building pressure (Hi-3) to mitigate the effects of a loss of coolant accident.

The delay time between detection of the accident condition and the generation of the actuation signal for these systems is assumed to be about 1.0 second; well within the capability of the protection system equipment. However, this time is short compared to that required for startup of the fluid systems.

The analyses in Chapter 15 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss of coolant.

7.3.2.4.2 Steam Line Break Protection

The Emergency Core Cooling System is also actuated in order to protect against a steam line break. Table 7.3-4 gives the time between sensing high steam line differential pressure or low steam line pressure and generation of the actuation signal. Analysis of steam line break accidents, assuming this delay for signal generation, shows that safety injection is actuated for a steam line break in time to limit or prevent further core damage for steam break cases. There is a reactor trip and the core reactivity is further reduced by the borated water injected by the Emergency Core Cooling System.

Additional protection against the effects of steam line break is provided by feedwater isolation which occurs upon actuation of the Emergency Core Cooling System. Feedwater isolation is initiated in order to prevent excessive cooldown of the reactor vessel and thus protect the Reactor Coolant System boundary.

Additional protection against a steam line break accident is provided by closure of all steam line isolation valves in order to prevent uncontrolled blowdown of all steam generators. The time for generation of the protection system signal (about 2.0 seconds) is again short compared to the time to trip the fast acting steam line isolation valves which are designed to close in less than approximately 5 seconds.

In addition to actuation of the engineered safety features, the effect of a steam line break accident also generates a signal resulting in a reactor trip on overpower or following Emergency Core Cooling System actuation. The core activity is further reduced by the Emergency Core Cooling System.

The analyses in Chapter 15 of the steam line break accidents and an evaluation of the protection system instrumentation and channel design shows that the Engineered Safety Features Actuation Systems are effective in preventing or mitigating the effects of a steam line break accident.

7.3.3 ELECTRIC HYDROGEN RECOMBINER-DESCRIPTION OF INSTRUMENTATION

The Electric Hydrogen Recombiner System is discussed in Section 6.2.5. Two (2) redundant recombiners, which are located inside the Reactor Building, do not require any instrumentation inside the Reactor Building for proper operation after a loss of coolant accident (LOCA). Thermocouples are provided for convenience in test and periodic checkout of the recombiner; however, they are not considered necessary to assure proper operation of the recombiner.

There are provided for each recombiner a control panel and a power supply panel which are located outside the Reactor Building, as shown on Figure 6.2.54 and Figure 6.2-58. The power supply panel contains an isolation transformer plus a controller to regulate power into the recombiners. The manually operated potentiometer for this controller is on the control panel. For equipment test and periodic checkout, a thermocouple readout instrument is also provided on the control panel for monitoring temperatures in the recombiner. To control the recombination process, the correct power input which will bring the recombiner above the threshold temperature for recombination will be set on the controller. Setting of the controller is accomplished at the local control panel and power input monitored by a wattmeter, which is also mounted on the control panel. This predetermined power setting will cover variations in Reactor Building pressure and hydrogen concentration in the post-loss of coolant accident environment. The manually operated switch for energizing a recombiner is on the control panel.

7.3.3.1 <u>Initiating Circuits</u>

The Hydrogen Recombiner System would be operated only during periodic testing and after a loss-of-coolant accident. Operation is initiated manually from the control station, so as to allow the heating elements within the unit to be energized. A 2 position switch is provided on the control panel for this purpose.

7.3.3.2 Logic

All operation of the electric hydrogen recombiner is by operator action; there are no automatic logic functions required. A post accident hydrogen analyzer will be used to indicate when the recombiners or the venting system should be actuated.

7.3.3.3 Bypasses

The electric hydrogen recombiners are normally not operating and are not armed for automatic actuation. Following an accident the elapsed time prior to the needed start of the equipment is in terms of hours or days. The recombiners are also operated during periodic testing. Other than these times they are in a standby mode. This standby mode is not a bypass mode, which refers to the inoperative status of systems that are normally operating.

7.3.3.4 Interlocks

There are no functional interlocks associated with the electric hydrogen recombiner.

7.3.3.5 Sequence

Each electric hydrogen recombiner is capable of being supplied from an independent onsite diesel generator. Loading on the emergency electric bus is by manual means, not by sequencers.

7.3.3.6 Redundancy

To meet the requirements for redundancy and independence, 2 electric hydrogen recombiners are provided, and each recombiner is provided with a separate power panel and control panel and each is powered from a separate Class 1E bus. The operation of a single unit is intended to provide the required hydrogen removal capability.

7.3.3.7 Diversity

Diversity between the redundant portions of the Electric Hydrogen Recombiner System is not required to protect against systematic failures, such as, multiple failures resulting from a credible single event. The design and environmental and seismic qualification of the Westinghouse electric hydrogen recombiner, as reported on in topical report WCAP-7709-L (Proprietary) with Supplements 1 to 7 and WCAP-7820 (Non-Proprietary), was found acceptable for the prototype and production models by the NRC. This acceptance was reported in NRC's letters of May 1, 1975 from D. B. Vassalo to C. Eicheldinger, Manager of W Nuclear Safety Department and of June 22, 1978 from John Stolz to T. M. Anderson regarding supplements 5, 6, and 7.

7.3.3.8 Actuated Devices

A manually operated switch on the control panel is used to initiate operation of an electric hydrogen recombiner. This switch energizes a contactor in the power supply panel which applies the 3-phase electric power source to the transformer, also in the power supply panel. Electric power input to the recombiner is controlled by a controller in the power supply panel, by means of a manually operated potentiometer and a wattmeter on the control panel. Electric power is fed to the recombiner's electric resistance heaters which are used to heat a continuous flow of Reactor Building atmosphere to the hydrogen-oxygen reaction temperature. This causes hydrogen to combine with the oxygen which is in the Reactor Building.

7.3.4 CROSS REFERENCES

Table 7.3-7 provides cross references outlining appropriate sections that supply descriptions of initiating circuitry, logic, bypasses, interlocks, sequencing, redundancy, diversity and actuated devices for ESF and ESF supporting systems.

7.3.5 REFERENCES

1. Reid, J. B., "Process Instrumentation for Westinghouse Nuclear Steam Supply System (4 Loop Plant using WCID 7300 Series Process Instrumentation)," WCAP-7913, 1973.

2. Katz, D. N., "Solid-State Logic Protection System Description," WCAP-7488-L (Proprietary), 1971 and WCAP-7672 (Non-Proprietary), 1971.

3. Swogger, J. W., "Testing of Engineered Safety Features Actuation System," WCAP-7705, Revision 2, 1976.

4. The Institute of Electrical and Electronics Engineers, Inc., "IEEE Standard: Criteria for Protection System for Nuclear Power Generating Stations," IEEE Standard 279-1971.

5. Eggleston, F. T., Rawlins, D. H., Petrow J. R., "Failure Mode and Effects Analysis (FMEA) of the Engineering Safeguard Features Actuation System," WCAP-8584, (Proprietary) 1976, and WCAP-8760 (Non-Proprietary), 1976.

TABLE 7.3-1

INSTRUMENTATION OPERATING CONDITION FOR ENGINEERED SAFETY FEATURES

Number		Function Unit	Number of Channels	Number of Channels to Trip
1.		Safety Injection (SIS)		
	a.	Manual	2	1
	b.	Reactor building pressure (Hi-1)	3	2
	c.	High differential pressure between steam lines	3/steam line	2 / steam line indicating that the steam line pressure is low in comparison to the two lines
	d.	Pressurizer low pressure (1)	3	2
	e.	Low steam line pressure	3 pressure signals	2
2.		Reactor Building Spray		
	a.	Manual (2)	4	2
	b.	Reactor building pressure (Hi-3) (3)	4	2

(1) Permissible bypass if reactor coolant pressure is less than 2,000 psig.

(2) Manual actuation of reactor building spray is accomplished by actuating either of two sets (two switches per set). Both switches in a set must be actuated to obtain a manually initiated spray signal.

(3) Coincident with containment isolation Phase A.

TABLE 7.3-6

ENGINEERED SAFETY FEATURE LOADING SEQUENCE CONTROL PANELS, DEGREE OF CONFORMANCE WITH REGULATORY GUIDE 1.53 AND IEEE-379-1972 [1]

Criteria		FSAR SECTION
Regulatory Guide 1.53		
C.1,	IEEE 379-1972	See IEEE 379 comparison below
C.2,	Continuity Checks	7.3.2.2.5.9
C.3,	Interconnections	7.1.2.1.7, 7.1.2.1.8, 7.1.2.2, 7.3.2.2, 7.3.2.2.3, 7.3.2.2.7
C.4,	Protection System Logic and Actuator System	7.3.2.2.5.9, 7.3.2.3
IEEE 379-1972		
3(1),	Redundancy	7.1.2.2, 7.3.1.1.3, 8.3.1.4
3(2),	Detectability	7.3.2.2.5.9
3(3),	Nondetectability	None identified, NA
3(4),	Multiple Faults	NA, included in 7.3.2.2.5.9
3(5),	Completing Protective Functions	7.3.2.2, 7.3.2.2.3, 8.3.1.4
3(6),	DBE and Single Failure	3.10, 3.11, 7.3.1.2.5
3(7),	Operational Reliability	NA, included in design concept
5.1,	Classification	NA, included in design concept
5.2,	Undetectable Failures	NA, testing features are provided to detect all failures
5.3,	Common Mode Failures	None identified, NA

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TABLE 7.3-6 (Continued)

ENGINEERED SAFETY FEATURE LOADING SEQUENCE CONTROL PANELS, DEGREE OF CONFORMANCE WITH REGULATORY GUIDE 1.53 AND IEEE-379-1972 [(1)]

Criteria		FSAR SECTION
IEEE 379-1972 (Continued)		
6.1,	General	7.1.2.2, 7.3.1.1, 7.3.1.1.3, 7.3.1.1.5, 7.3.2.4
6.2,	Channels	NA, included in design concept
6.3,	Protection System Logic	NA, redundant logic is completely separate
6.4,	Actuator Circuit	NA to this equipment
6.5,	Type 2 and 3 Single Failure Analysis	3.10, 3.11, 7.3.1.2.5, 7.3.2.3
6.6,	Overall System - Failure Analysis	NA, no interconnection between control and protective systems for this equipment

NOTE:

(1) Formal analyses have not been provided. However, FSAR Sections referenced indicate compliance with the concept outlined in the criteria.

TABLE 7.3-7

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number	
Engineered Safety Features System	Engineered Safety Features Actuation System (ESFAS)	7.1.2.5, 7.1.2.6, 7.3.1.1,	7.2-1 Sh. 8 7.3-1	-	
		7.3.2.2.3, 7.3.2.2.5.5,	7.3-2	-	
		7.3.2.2.6, 7.5.4	7.3-3	-	
		Tables 7.3-1, 7.3-3	7.5-1 thru 7.5-6		
			-	B-208-066	
			-	B-208-094	
				B-208-103	
				D-2544-1013	
				7244D38 (1MS-42-017)	99-01
	Reactor Building Heat Removal				
	Reactor Building Ventilation	6.2.2.2.2.1, 6.2.2.2.2.2,	6.2-49	-	00-01
		6.2.2.5.2.2, 7.1.2.6, 7.3.1.1,	7.3-1	-	
		7.3.1.1.6, 7.5.4, 9.2.1.5,	-	B-208-004	00-01
		9.4.7.2.5,		Sh AH273 thru AH276	
		Notes 3, 6	-	8756D01 (1MS-51-221)	99-01
	Reactor Building Spray System	6.2.2.2.1, 6.2.2.5.1.6, 7.1.2.6,	6.2-46	-	
		7.3.1.1, 7.3.1.1.6, 7.5.4	-	B-208-005	00-01
			-	B-208-097	
		Notes 3, 6	-	8756D01 (1MS-51-221)	99-01
	Reactor Building Air Purification and Cleanup	6.2.2.2.1, 6.2.2.5.1.6, 6.2.3,	6.2-46	-	
		7.3.1.1, 7.3.1.1.6, 7.5.4	-	B-208-005	00-01
			-	B-208-097	
		Notes 3, 6	-	8756D01 (1MS-51-221)	99-01

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number	
Engineered Safety Features System	Containment Isolation	6.2.4, 7.3.1.1, 7.5.4 Tables 6.2-54, 7.3-2 Notes 3, 6	6.2-52	-	00-01
	Combustible Gas Control	6.2.4, 6.2.5, 7.3.3 Table 6.2-54	6.2-54 6.2-58	- B-208-054	
	Containment Leakage Testing	6.2.6, 6.2.6.1.5 Note 7	6.2-59 6.2-60	- -	
	Safety Injection System				
	Isolation Valves - Accumulator N_2 Supply (8880)	6.2.4, 6.3.2.2.7, 6.3.5.5, 7.1.2.5, 6.3.2.11.1, 7.3.1.1, 7.5.4 Tables 7.3-1, 7.3-2, 7.3-3, 6.2-54 Notes 2, 3, 4, 6	6.3-1 Sh 2	B-208-095 Sh SI72	00-01
	Isolation Valves - Accumulator Test (8871 & 8961)	6.2.4, 6.3.2.2.7, 6.3.5.5, 7.1.2.5, 6.3.2.11.1, 7.3.1.1, 7.5.4 Tables 7.3-1, 7.3-2, 7.3-3, 6.2-54 Notes 2, 3, 4, 6	6.3-1 Sh 2	B-208-095, Sh SI59, SI76	
	Isolation Valves - Accumulator Fill Line (8860)	6.2.4, 6.3.2.2.7, 7.1.2.5, 6.3.2.11.1, 6.3.5.5, 7.3.1.1, 7.5.4 Tables 6.2-54, 7.3-1, 7.3-3 Notes 2, 3, 4, 6	6.3-1 Sh 2	B-208-095, Sh SI58	

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference: FSAR Sections	Related Drawings [1]: FSAR Figure	Related Drawings [1]: Drawing Number	
Engineered Safety Features System	Sump Isolation Valves (Recirc. following SI) 8811A, B, & 8812A, B	6.2.4, 6.3.2.2.7, 6.3.5.5, 6.3.2.11.1, 7.6.7 Tables 6.2-54, 7.3-1, 7.3-3 Note 3	7.6-9	B-208-095, Sh SI-21, 22, 23, 24	00-01
	Isolation Valves (8801A & B)	6.2.4, 6.3.2.2.7, 6.3.5.5, 7.1.2.5, 6.3.2.11, 7.3.1.1 Tables 6.2-54, 7.3-1, 7.3-3, 6.3-7 Notes 2, 3, 5, 6	6.3-1 Sh1	B-208-095 Sh SI09, 10, 11, 12	
	Isolation Valves - Accumulator (8808A, B, C)	6.3.2.2.7, 7.6.4, 6.3.2.11, 7.3.1.1, 6.3.2.15 Tables 7.3-1. 7.3-2. 7.3-3 Notes 2, 3, 5	7.6-2	B-208-095, Sh SI-16, 17, 18	
	RHR/LO-HEAD SI Pump	6.3.2.2.7, 6.3.2.2.4.1, 7.1.2.5, 7.3.1.1, 7.3.1.1.6, 6.3.2.11.1 Tables 7.3-1, 7.3-3, 8.3-3, 6.3-7 Notes 3, 5, 6	6.3-2 Sh 3 7.3-1	B-208-084 Sh RH-01, 02	00-01
	CENT. CHARGING/HI HEAD SI Pump	6.3.2.2.4.2, 6.3.2.2.7, 7.1.2.5, 7.3.1.1.5, 6.3.2.11.1, 7.3.1.1 Tables 7.3-1, 7.3-3, 8.3-3, 6.3-7 Notes 3, 5, 6	6.3-1 Sh 1 7.3-1	B-208-021 Sh CS-04, 05, 06, 07, 08	

TABLE 7.3-7 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference: FSAR Sections	Related Drawings (1): FSAR Figure	Related Drawings (1): Drawing Number	
Engineered Safety Features System	Habitability Systems	6.4, 6.4.1.5, 7.3.1.1, 7.3.1.1.5 Note 6	9.4-1	- B-208-04, Sh AH102 thru AH105	
	Fission Product Removal and Control Systems				
	Reactor Building Cooling Unit HEPA Filters	6.2.2.2.2, 6.2.2.5.2, 6.5.1.3, 6.5.1.5.1, 7.3.1.1, 7.5.4 Notes 3, 6	6.2-49	- B-208-004, Sh AH273 thru AH284	
	Control Room Emergency Filter Plenums	6.4, 6.4.1.5, 6.5.1.3, 6.5.1.5.2, 7.3.1.1, 7.3.1.1.5, 9.4.1.2.1, 9.4.1.3 Note 6	9.4-1 -	B-208-004, Sh AH102, AH103	
	Fuel Handling Building Charcoal Exhaust System	6.5.1.3, 6.5.1.5.3, 7.3.1.1, 7.3.1.1.5, 9.4.3.2.1, 9.4.3.3 Notes 3, 6	7.3-1 9.4-11 - -	- - B-208-004 Sh AH174, AH175 8576D01 (1MS-51-221)	99-01
	Emergency Feedwater System	7.1, 7.3.1.1 7.3.1.1.5, 7.5.4 10.4.9.2, 10.4.9.3 10.4.9.5 Note 6	7.3-1 10.4-16 - -	- - B-208-032, 8576D01 (1MS-51-221)	99-01

TABLE 7.3-7 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number	
Engineered Safety Features Supporting Systems	Component Cooling Water System	7.1, 7.1.2.6, 7.3.1.1,	7.3-1	-	
		7.3.1.1.5, 7.4, 7.5.4,	9.2-4 thru	-	
		9.2.2.1, 9.2.2.2, 9.2.2.3,	9.2-7	-	
		9.2.2.5, 11.4.2	-	B-208-005	
		Note 3	-	B-208-011	
	Diesel Generator System	7.3.1.1, 7.4, 8.3.1.1.2,	8.2-3	-	
		9.5.4.2, 9.5.4.3, 9.5.4.5,	8.3-0h thru	-	
		9.5.5.3, 9.5.5.5, 9.5.6.1,	8.3-0j	-	
		9.5.7.3, 9.5.7.5, 9.5.8.3	9.5-2		
			9.5-3		
		Notes 3, 6	9.5-4		
			9.5-6		
			9.5-7		
			-	B-208-005	
			-	B-208-023	
Engineered Safety Features System	Service Water System	7.1, 7.1.2.6, 7.3.1.1,	7.3-1	-	
		7.3.1.1.5, 7.4, 7.5.4,	9.2-1	-	
		9.2.1.2, 9.2.1.3	9.2-2	-	
		9.2.1.5	-	B-208-005	
			-	B-208-101	
		Note 3	-	8756D01 (1MS-51-221)	99-01
	Chilled Water System	7.1.2.6, 7.3.1.1, 7.3.2.2.5,	7.3-1	-	
		7.5.4, 9.4.7.2.4, 9.4.7.3	9.4-22	-	
			9.4-23	-	
			9.4-24	-	
		Note 3	-	B-208-005	
			-	B-208-109	
			-	8756D01 (1MS-51-221)	99-01

TABLE 7.3-7 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings [1] FSAR Figure	Related Drawings [1] Drawing Number	
Engineered Safety Features System	Heating, Ventilating and Air Conditioning Systems				
	Auxiliary and Fuel Handling Building Ventilation Systems	6.5.1.3, 6.5.1.5.3, 7.3.1.1, 7.3.1.1.5, 9.4.2.1, 9.4.2.2, 9.4.2.3, 9.4.3.2, 9.4.3.3	7.3-1	-	
			9.4-10	-	
			9.4-11	-	
		Notes 3, 6	-	B-208-004 Sh AH174, AH175	
			-	B-208-108, Sh VL05 thru VL09	
			-	8756D01 (1MS-51-221)	99-01
	Control Building Ventilation Systems	6.4, 6.4.1.5, 6.5.1.3, 6.5.1.5.2, 7.3.1.1, 7.3.1.1.5, 9.4.1.2, 9.4.1.3, 12.2.4.2.1	9.4-1	-	
			9.4-2	-	
			9.4-3	-	
			9.4-5	-	
		Note 6	-	B-208-004, Sh AH102 thru AH105, AH107, AH108, AH147, AH148	
			-	8756D01 (1MS-51-221)	99-01
	Diesel Generator Building Ventilation System	7.3.1.1.5, 8.3.1.1.2.4, 9.4.7.2.1, 9.4.7.3	9.4-18	B-208-004, Sh AH 164 thru AH167	
		Notes 2, 3, 6	-		

TABLE 7.3-7 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings (1) FSAR Figure	Related Drawings (1) Drawing Number	
Engineered Safety Features System	Intermediate Building Ventilation System	7.3.1.1, 7.3.1.1.5, 9.4.6.2, 9.4.6.3	9.4-15 thru 9.4-17 -	- - B-208-004 Sh AH194 thru AH197 B-208-108 Sh VL18, VL19, VL22, VL24, VL26, VL27, VL30, VL31 8756D01 (1MS-51-221)	99-01
	Reactor Building Ventilation Systems	6.2.2.2.2.1, 6.2.2.2.2.2, 6.2.2.5.2.2, 7.1.2.6 7.3.1.1, 7.3.1.1.5, 7.5.4, 9.2.1.5, 9.4.7.2.5, Notes 3, 6	6.2-49 7.3-1 -	- - - B-208-004 Sh AH273 thru AH276 8756D01 (1MS-51-221)	99-01
	Service Water Pumphouse Ventilation System	7.3.1.1.5, 9.4.7.2.2, 9.4.7.3	9.4-19 - -	B-208-004 Sh AH326 thru AH331 8756D01 (1MS-51-221)	99-01

1. FSAR figure numbers refer to figures in the FSAR; drawing numbers refer to drawings in the Wiring Schematic Package (see Section 1.7)

2. Not sequenced

3. Not diverse

4. Solenoid valve is the actuation device

5. Motor Control Center is actuation device

6. No Interlocks or Bypasses are provided which would inhibit ESF actuation.

7. The containment leakage testing system is not an Engineered Safety Features System or an essential Auxiliary Supporting System. The system includes only that equipment and instrumentation required to perform the initial and periodic containment leakage testing during plant shutdown. All penetrations through containment are capped during normal plant operation.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The functions necessary for safe shutdown are available from instrumentation channels that are associated with the major systems in both the primary and secondary of the Nuclear Steam Supply System. These channels are normally aligned to serve a variety of operational functions, including startup and shutdown as well as protective functions. There are no identifiable safe shutdown systems per se. However, prescribed procedures for securing and maintaining the plant in a safe condition can be instituted by appropriate alignment of selected systems in the Nuclear Steam Supply System. The discussion of these systems together with the applicable codes, criteria and guidelines is found in other sections of this Final Safety Analysis Report. In addition the alignment of shutdown functions associated with the engineered safety features which are invoked under postulated limiting fault situations is discussed in Chapter 6 and Section 7.3.

The instrumentation and control functions which are required to be aligned for maintaining safe shutdown of the reactor that are discussed in this section are the minimum number under nonaccident conditions. These functions will permit the necessary operations that will:

1. Prevent the reactor from achieving criticality in violation of the Technical Specifications and

2. Provide an adequate heat sink such that design and safety limits are not exceeded.

7.4.1 DESCRIPTION

The designation of systems that can be used for safe shutdown depends on identifying those systems which provide the following capabilities for maintaining a safe shutdown:

1. Boration (see Section 9.3.4, "Chemical and Volume Control System").

2. Adequate supply for emergency feedwater (see Section 10.4.9, "Emergency Feedwater System").

3. Residual heat removal (see Section 5.5.7, "Residual Heat Removal System").

These systems are identified in the following lists together with the associated instrumentation and controls provisions. The identification of the monitoring indicators (Section 7.4.1.1) and controls (Section 7.4.1.2) are those necessary for maintaining a hot shutdown. The equipment and services available for a cold shutdown are identified in Section 7.4.1.4. 00-01

7.4.1.1 Monitoring Indicators

Safety related display instrumentation, as described in Section 7.5, is provided outside as well as inside the Control Room. The necessary indicators for maintaining a hot shutdown are as follows: 00-01

1. Water level indicator for each steam generator [1].

2. Pressure indicator for each steam generator [1].

3. Pressurizer water level indicator [1].

4. Pressurizer pressure indicator [1].

In addition, the following indicators are also provided:

1. Reactor Building temperature [1].

2. Volume control tank level [1].

3. Charging pressure and flow [1].

4. Emergency boration flow [1].

5. Condensate storage tank level [1].

6. Letdown flow [1].

7.4.1.2 Controls

7.4.1.2.1 General Considerations

1. The turbine is tripped. (Note that this can be accomplished at the turbine as well as in the Control Room.)

2. The reactor is tripped. (Note that this can be accomplished at the reactor trip switchgear as well as in the Control Room.)

3. All automatic systems continued functioning. (Discussed in Sections 7.2 and 7.7.)

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(1) Indication is physically located on the Control Room Evacuation Panel (CREP).

4. For certain equipment having motor controls outside the Control Room (which duplicate the functions inside the Control Room) the controls are provided with a selector switch at the local station which transfers control of the switchgear from the Control Room to the local station(s). Placing the local selector switch in the local operating position will give an annunciating alarm in the Control Room. The transfer switches are designed so that after the transfer switch is in the local position, a failure in the Control Room or Cable Spreading Room does not cause a failure in the local control. Also, a failure in the local control circuit beyond the transfer switch does not cause a failure in the remote control circuit when the control is transferred there. The following equipment is provided with transfer switches:

    a. Pressurizer heater backup group 1 (4) (see Section 5.5.10, "Pressurizer").

    b. Pressurizer heater backup group 2 (4) (see Section 5.5.10, "Pressurizer").

    c. Charging flow controller (setpoint station) (see Section 9.3.4, "Chemical and Volume Control System").

    d. Emergency borate valve (see Section 9.3.4, "Chemical and Volume Control System").

    e. Turbine driven emergency feedwater pump flow control valves (see Section 10.4.9, "Emergency Feedwater System").

    f. Motor driven emergency feedwater pump flow control valves (see Section 10.4.9, "Emergency Feedwater System).

    g. Letdown line isolation valves (see Section 9.3.4, "Chemical and Volume Control System").

    h. Letdown orifice A, B, and C isolation valves (see Section 9.3.4, "Chemical and Volume Control System").

    i. Steam supply valve to emergency feedwater pump turbine (see Section 10.4.9, "Emergency Feedwater System").

    j. Emergency feedwater pump turbine speed control (setpoint station) (See Section 10.4.9, "Emergency Feedwater System").

    k. Service water pumps A and B (see Section 9.2.1, "Service Water System").

    l. Service water pump C (as part of A train and as part of B train) (see Section 9.2.1, "Service Water System").

m. Boric acid transfer pump B (see Section 9.3.4, "Chemical and Volume Control System").

n. Pressurizer power operated relief valves PCV445A and PCV444B (see Section 5.5.13, "Safety and Relief Valves").

The backup heater groups are designed to be available during plant operations required to maintain hot shutdown or bring the plant to cold shutdown. However, this availability is not a mandatory requirement for maintaining hot shutdown or for bringing the plant to cold shutdown.

These switches are shown by Figures 7.4-1 through 7.4-2.

Use of the transfer switch removes the automatic actuation capability for the following components (such as motors):

a. Pressurizer heater backup group 1 (see Section 5.5.10, "Pressurizer").

b. Pressurizer heater backup group 2 (see Section 5.5.10, "Pressurizer").

c. Service water pumps (see Section 9.2.1, "Service Water System").

d. Boric acid transfer pump B (see Section 9.3.4, "Chemical and Volume Control System").

e. Pressurizer power operated relief valves PCV445A and PCV444B (see Section 5.5.13, "Safety and Relief Valves").

Removal of this automatic actuation capability does not jeopardize plant safety, since no accident is postulated to occur concurrent with the need for this transfer.

5. Certain motor operated valves, such as for service water backup water supply to the Emergency Feedwater System (see Section 10.4.9, "Emergency Feedwater System") will have their electrical operators disconnected and the valves will be positioned manually by disconnecting the main circuit breaker at the motor control center and operating the valve by means of the handwheel after depressing a lever in the direction marked "Manual Control".

6. Certain pumps will be controlled from their motor switchgear mechanical switches. The ability to perform the shutdown function is not jeopardized by a failure in the Control Room or Cable Spreading Room since redundant equipment could be used. In the unlikely event that a failure in the Control Room or Cable Spreading Room short circuits the switchgear trip circuit, local operation of the switchgear (without control power) would isolate this fault. Such operation can be accomplished as follows:

a. Remove both the closing and trip fuses to isolate d-c control voltage.

b. Manually close the circuit breaker utilizing operating mechanism located on the breaker.

c. Manually trip the circuit breaker utilizing operating mechanism located on the breaker.

7. Certain redundant equipment (air compressors, see Section 9.3.1, "Compressed Air Systems"); heating, ventilating and air conditioning chillers (see Section 9.4.7, "Miscellaneous Building Ventilation and Cooling Systems"); and diesel generators (see Sections 8.3.1.1.2, "Onsite Standby Power Supply," and 9.5, "Other Auxiliary Systems") have comprehensive local control cabinets with functionally parallel start/stop controls extended to the Control Room. The ability to perform the shutdown function is not jeopardized by a failure in the Control Room or Cable Spreading Room since redundant equipment could be used. In the unlikely event that a failure in the Control Room or Cable Spreading Room prevents local control of this equipment, isolation of the fault in parallel control circuits would require removal of the external control wires at the local control cabinets.

7.4.1.2.2 Pumps and Fans

1. Emergency feedwater pumps

   In the event of a trip of all main feedwater pumps (see Section 10.4.7, "Condensate and Feedwater Systems"), feedwater pumps (see Section 10.4.9, "Emergency Feedwater System") start automatically or can be started manually. Start/stop motor controls located locally (as well as being inside the Control Room) are provided as well as handwheel control for the valves.

2. Charging and boric acid transfer pumps

   Start/stop control for both boric acid pumps is located in the Control Room. In addition, control for one pump is located at CREP.

   The start/stop control for 3 charging pumps is located in the Control Room. In addition, controls for "B" pump and "C" pump aligned to "B" train are located at their respective switchgear. Also, all circuit breakers for the 3 pumps can be closed or tripped utilizing the operating mechanisms located on their respective breakers.

3. Service water pumps[(2)] (see Section 9.2.1, "Service Water System").

   Start/stop motor controls are located outside as well as inside the Control Room.

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(2) Control and indication are physically located on the CREP.

4. Component cooling water pumps (see Section 9.2.2, "Component Cooling Water System").

   The circuit breakers can be closed or tripped from operating mechanisms located on their respective breakers.

5. Instrument air compressors (see Section 9.3.1, "Compressed Air Systems"). These compressors start automatically on low air pressure.

6. Reactor building cooling units (see Section 6.2.2, "Reactor Building Heat Removal Systems").

   Start/stop motor controls with a selector switch are provided for the fan motors. The controls are located outside as well as inside the Control Room.

7.4.1.2.3 Diesel Generators (see Section 8.3.1.1.2, "Onsite Standby Power Supply," and 9.5, "Other Auxiliary Systems")

These units start automatically following a loss of voltage on their respective buses. However, manual controls for diesel startup are also provided locally at the diesel generators (as well as inside the Control Room).

7.4.1.2.4 Valves and Heaters

1. Charging flow control valves(2) (see Section 9.3.4, "Chemical and Volume Control System")

   Remote manual control with a selector switch for the charging line flow control valves is provided outside, as well as inside, Control Room. These controls duplicate functions that are available inside the Control Room.

2. Letdown orifice isolation valves(2) (see Section 9.3.4, "Chemical and Volume Control System").

   Open/close controls with a selector switch for the letdown orifice isolation valves are grouped with the controls for the charging flow control valve. These controls duplicate functions that are inside the Control Room.

3. Emergency feedwater control valves(2) (see Section 10.4.9, "Emergency Feedwater System")

   Controls for these valves are located outside as well as inside the Control Room.

(2) Control and indication are physically located on the CREP.

4. Condenser steam dump and atmospheric steam relief valves (see Section 10.4.4, "Turbine Bypass System")

   The condenser steam dump and atmospheric relief valves are automatically controlled. Manual control is provided locally as well as inside the Control Room for the atmospheric relief valves. Steam dump to the condenser is blocked on high condenser pressure.

5. Pressurizer heater control [2] (see Section 7.7.1.5, "Pressurizer Pressure Control")

   On/off control with selector switch is provided for 2 backup heater groups. The heater groups are connected to separate buses, such that each can be connected to separate diesels in the event of loss of outside power. The controls are grouped with the charging flow controls and duplicate functions that are available inside the Control Room.

7.4.1.3 Control Room Evacuation

The instrumentation and controls listed in Sections 7.4.1.1 and 7.4.1.2 that are used to achieve and maintain a safe shutdown are available in the event an evacuation of the Control Room is required. These controls and instrumentation channels together with the equipment identified in Section 7.4.1.4 identify the potential capability for cold shutdown of the reactor subsequent to a Control Room evacuation through the use of suitable procedures. Table 7.4-1 and Figures 7.4-1 through 7.4-2 address the local control stations and the relative locations of these control stations in the plant. The design basis for Control Room evacuation does not consider a concurrent Condition II, III, or IV event, nor a single failure.

Control Room evacuation resulting from a fire in the control complex and the ability to achieve safe shutdown concurrent with the fire is demonstrated in the Virgil C. Summer Nuclear Station FPER. 00-01

(2) Control and indication are physically located on the CREP

7.4.1.4 Equipment and Systems Available for Cold Shutdown

1. Reactor coolant pumps (see Section 5.5.1, "Reactor Coolant Pumps").

2. Emergency feedwater pumps (see Section 10.4.9, "Emergency Feedwater System").

3. Boric acid transfer pumps (see Section 9.3.4, "Chemical and Volume Control System").

4. Charging pumps (see Section 9.3.4, "Chemical and Volume Control System").

5. Service water pumps (see Section 9.2.1, "Service Water System").

6. Reactor building fans (see Section 6.2.2, "Reactor Building Heat Removal Systems," and Section 9.4.8, "Reactor Building Cooling and Filtering Systems").

7. Component cooling water pumps (see Section 9.2.2, "Component Cooling Water System").

8. Residual heat removal pumps (see Section 5.5.7, "Residual Heat Removal System)[3].

9. Certain motor control center and switchgear Sections (see Section 8.3, "Onsite Power Systems").

10. Controlled steam release and feedwater supply (see Sections 7.7.1.8, "Steam Dump Control" and 10.4.4, "Turbine Bypass System").

11. Boration capability (see Section 9.3.4, "Chemical and Volume Control System").

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(3) Instrumentation and controls for these systems may require some modification in order that their functions may be performed from outside the Control Room. Note that the reactor plant design does not preclude attaining the cold shutdown condition from outside the Control Room. An assessment of plant conditions can be made on the long term basis (a week or more) to establish procedures for making the necessary physical modifications to instrumentation and control equipment in order to attain cold shutdown. During such time the plant could be safely maintained at hot shutdown condition.

Detailed procedures to be followed in effecting cold shutdown from outside the Control Room are best determined by plant personnel at the time of the postulated incident.

12. Nuclear Instrumentation System source and intermediate ranges (both ranges are provided remote from the Control Room, but only source range is independent of the Control Room). (See Sections 7.2, "Reactor Trip System," and 7.7, "Control Systems Not Required for Safety").

13. Reactor coolant inventory control (charging and letdown) (see Section 9.3.4, "Chemical and Volume Control System").

14. Pressurizer pressure control including opening control for pressurizer relief valves (heaters and spray) (see Section 7.7.1.5, "Pressurizer Pressure Control"). [3]

In addition, the safety injection signal trip circuit must be defeated and the accumulator isolation valves closed [3] (see Sections 6.3, "Emergency Core Cooling System," and 7.3, "Engineered Safety Features Actuation System").

The Virgil C. Summer Nuclear Station FPER identifies equipment and systems used to achieve cold shutdown in the event of a fire in the plant. 00-01

7.4.2 ANALYSIS

Hot shutdown is a stable plant condition, automatically reached following a plant shutdown. The hot shutdown condition can be maintained safely for an extended period of time. In the unlikely event that access to the Control Room is restricted, the plant can be safely kept at a hot shutdown until the Control Room can be re-entered by the use of the monitoring indicators and the controls listed in Sections 7.4.1.1 and 7.4.1.2. These indicators and controls are provided outside as well as inside the Control Room.

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(3) Instrumentation and controls for these systems may require some modification in order that their functions may be performed from outside the Control Room. Note that the reactor plant design does not preclude attaining the cold shutdown condition from outside the Control Room. An assessment of plant conditions can be made on the long term basis (a week or more) to establish procedures for making the necessary physical modifications to instrumentation and control equipment in order to attain cold shutdown. During such time the plant could be safely maintained at hot shutdown condition.

Detailed procedures to be followed in effecting cold shutdown from outside the control room are best determined by plant personnel at the time of the postulated incident.

The safety evaluation of the maintenance of a shutdown with these systems and associated instrumentation and controls has included consideration of the accident consequences that might jeopardize safe shutdown conditions. The accident consequences that are germane are those that would tend to degrade the capabilities for boration, adequate supply for emergency feedwater, and residual heat removal.

The results of the accident analysis are presented in Chapter 15. Of these the following produce the most severe consequences that are pertinent:

1. Uncontrolled Boron Dilution.

2. Loss of Normal Feedwater.

3. Loss of External Electrical Load and/or Turbine Trip.

4. Loss of Offsite Power to the Station Auxiliaries.

It is shown by these analyses that safety is not adversely affected by these incidents with the associated assumptions being that the instrumentation and controls indicated in Sections 7.4.1.1 and 7.4.1.2 are available to control and/or monitor shutdown. These available systems will allow a maintenance of hot shutdown even under the accident conditions listed above which would tend toward a return to criticality or a loss of heat sink.

The results of the analysis which determined the applicability to the Nuclear Steam Supply System safe shutdown systems of the NRC General Design Criteria, IEEE Standard 279-1971, applicable NRC Regulatory Guides and other industry standards are presented in Table 7.1-1. The functions considered and listed below include both safety-related and nonsafety-related equipment.

1. Reactor Trip System (see Section 7.2, "Reactor Trip System").

2. Engineered Safety Features Actuation System (see Section 7.3, "Engineered Safety Features Actuation System").

3. Safety-related display instrumentation for post accident monitoring (see Section 7.5, "Safety-Related Display Instrumentation").

4. Main control board (see Chapter 7.0, "Instrumentation and Controls").

5. Control room evacuation panel (see Sections 7.4.1.1, "Monitoring Indicators," and 7.4.1.2, "Controls).

6. Residual heat removal (see Section 5.5.7, "Residual Heat Removal System").

7. Instrument power supply (see Section 8.3, "Onsite Power Systems").

8. Control systems (see Chapter 7.0, "Instrumentation and Controls").

For the discussions addressing how these requirements are satisfied, the column in Table 7.1-1 entitled "Conformance Discussed In" provides the appropriate reference.

An analysis demonstrating the ability to achieve safe shutdown in the event of a fire is presented in the Virgil C. Summer Nuclear Station FPER. 00-01

7.4.2.1 Conformance to General Design Criterion 19

As noted in Section 7.4.1.3, equipment is provided outside the Control Room with a design capability for prompt hot shutdown of the reactor and for maintaining the unit in a safe condition during hot shutdown and with a potential capability for subsequent cold shutdown through the use of suitable procedures. For criteria relative to the control board in the Main Control Room, see Section 7.1.2.2.2.

7.4.2.2 Conformance to IEEE Standard 279-1971

The design basis information requested by Section 3 of IEEE Standard 279-1971 for protective action and pertaining to the signals for actuation of reactor trip are presented in Section 7.2.1.2. The analyses for compliance to the criteria of IEEE Standard 279-1971 for the reactor trip are addressed in Section 7.2.2. The design basis information for protective action for the Engineered Safety Features Actuation system (ESFAS) is presented in Section 7.3.1.2 and the analyses for ESFAS are addressed in Section 7.3.2. For the list of references to the discussions of conformance to applicable criteria, see Tables 7.1-1 and 7.1-2.

7.4.3 CROSS REFERENCES

Table 7.4-2 provides cross references outlining appropriate sections that supply descriptions of initiating circuitry, logic, bypasses, interlocks, redundancy, diversity and actuated devices for systems required for safe shutdown.

TABLE 7.4-1

SUMMARY OF LOCAL CONTROL STATIONS

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Residual Heat Removal Pumps		
XPN 6020 (ESF sequencer)	1.2-15	36-11
XPN 6025 (ESF sequencer)	1.2-15	36-11
XSW 1DA1 Unit No. 6A	1.2-13	63-01
XSW 1DB1 Unit No. 5D	1.2-6	63-01
Pressurizer Relief Valves		
XPN 7031 (Aux. relay rack No. 1)	1.2-15	36-11
XPN 7032 (Aux. relay rack No. 2)	1.2-15	36-11
XPN 7200A	1.2-12	36-03A
XPN 7200B	1.2-12	36-03
Pressurizer Relief Valve Isolation Valves		
XMC1DA2X	1.2-13	63-01
XMC1DB2X	1.2-12	36-01
Pressurizer Heater Control Group		
APN 4103 (Pressurizer controller)	1.2-5	36-18
XPN 7008 (Process cabinet)	1.2-15	36-11
XSW1C Unit 2	1.2-18	12-01
Diesel Generators		
XCX5201 control cabinet	1.2-12	36-04
XCX5202 control cabinet	1.2-12	36-03
Charging Flow Control Valves		
XPN 7200A	1.2-12	36-03A

TABLE 7.4-1 (Continued)

SUMMARY OF LOCAL CONTROL STATIONS

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Letdown Orifice Isolation Valves		
XPN 7200A	1.2-12	36-03A
XPN 7200B	1.2-12	36-03
Emergency Feedwater Control Valves		
XPN 7200A	1.2-12	36-03A
XPN 7200B	1.2-12	36-03
Condenser Steam Dump and Atmospheric Relief Valves		
XPN 6001 (BOP panel)	1.2-15	36-11
XPN 6002 (BOP panel)	1.2-15	36-11
XPN 7003 (Aux. relay rack)	1.2-15	36-11
XPN 7034 (Aux. cabinet)	1.2-15	36-11
XPN 7035 (Aux. cabinet)	1.2-15	36-11
XPN 7115 (Termination cabinet)	1.2-16	48-02
Safety Injection Accumulator Isolation Valves		
XMC1DA2X Unit 8AE	1.2-13	63-01
XMC1DA2X Unit 8FJ	1.2-13	63-01
XMC1DA2X Unit 161M	1.2-6	63-01
Emergency Feedwater Pumps		
XPN 7200B	1.2-12	36-03
XSW1DA Unit 13	1.2-13	63-01
XSW1DB Unit 03	1.2-12	36-01 | 99-01

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Amendment 00-01

TABLE 7.4-1 (Continued)

SUMMARY OF LOCAL CONTROL STATIONS

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.	
Charging and Boric Acid Transfer Pumps			
XPN 7200B	1.2-12	36-03	
XMC1DA2Y Unit 4CD	1.2-4	12-28	99-01
XMC1DB2Y Unit 10GH	1.2-6	63-01	
XMC1A3X Unit 6HJ	1.2-6	63-14	99-01
XMC1B3X Unit 6IK	1.2-6	63-09	
Service Water Pumps			
XPN 7200A	1.2-12	36-03A	
XPN 7200B	1.2-12	36-03	
Component Cooling Water Pumps			
XSW1DA Unit 8	1.2-13	63-01	
XSW1DB Unit 13	1.2-12	36-01	99-01
Instrument Air Compressors			
XSW1DA1	1.2-13	63-01	
XSW1DB1	1.2-6	63-01	
Reactor Building Cooling Units			
XSW1DA1	1.2-13	63-01	99-01
XSW1DB1	1.2-6	63-01	

TABLE 7.4-1 (Continued)

SUMMARY OF LOCAL CONTROL STATIONS

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.	
Pressurizer Heater Backup Group 1			
APN4101 (Pressurizer Controller)	1.2-5	36-18	
XPN 7031 (Aux. relay rack No. 1)	1.2-15	36-11	
XPN 7200A	1.2-12	36-03A	
XSW1DA Unit 2	1.2-13	63-01	
Pressurizer Heater Backup Group 2			
APN4102 (Pressurizer controller)	1.2-5	36-18	
XPN 7032 (Aux. relay rack No. 2)	1.2-15	36-11	
XPN 7022B	1.2-12	36-03	
XSW1DB Unit 5	1.2-12	36-01	
Pressurizer Spray Valve			
XPN 7008 (Process cabinet)	1.2-15	36-11	
Nuclear Instrumentation System - Source and Intermediate Range			
XPN 7051 (Computer)	1.2-15	36-10	
XPN 7113 (Main control board termination cabinet)	1.2-16	48-02	
XPN 7200A	1.2-12	36-03A	99-01
Safety Injection Trip Circuit			
XPN 7010 (Solid state protection)	1.2-15	36-11	
XPN 7020 (Solid state protection)	1.2-15	36-11	
XPN 7180 (Main control board termination cabinet	1.2-16	48-02	

TABLE 7.4-1 (Continued)

SUMMARY OF LOCAL CONTROL STATIONS

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Service Water to Emergency Feedwater System Valves		
XMC1DA2X Unit 4 EH	1.2-13	63-01
XMC1DA2X Unit 4 IL	1.2-13	63-01
XMC1DA2X Unit 12 AD	1.2-13	63-01
XMC1DB2X Unit 3 AD	1.2-12	36-01
XMC1DB2X Unit 3 EH	1.2-12	36-01
XMC1DB2X Unit 7 EH	1.2-12	36-01
Reactor Coolant System to Residual Heat Removal System Suction Valves		
XMC1DA2X Unit 7 FJ	1.2-13	63-01
XMC1DA2Y Unit 18 IM	1.2-4	12-28
XMC1DB2Y Unit 4 AE	1.2-6	63-01
XMC1DB2Y Unit 4 FJ	1.2-6	63-01
Borated Water to Charging Pump Valves		
XMC1DA2Y Unit 2 AD	1.2-4	12-28
XMC1DB2Y Unit 9 EH	1.2-6	63-01
XMC1DB2Y Unit 21 EH	1.2-6	63-01
Service Water Booster Pumps		
XSW1DA1 Unit 7A	1.2-13	63-01
XSW1DB1 Unit 5A	1.2-6	63-01

00-01

TABLE 7.4-1 (Continued)

SUMMARY OF LOCAL CONTROL STATIONS

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
Cooling Water Valves to Reactor Building Cooling Units		
XMC1DA2X Unit 12 IM	1.2-13	63-01
XMC1DA2X Unit 13 AD	1.2-13	63-01
XMC1DA2X Unit 13 EH	1.2-13	63-01
XMC1DA2X Unit 14 EH	1.2-13	63-01
XMC1DA2Y Unit 16 EH	1.2-4	12-28
XMC1DB2X Unit 18 EH	1.2-6	63-01
XMC1DB2Y Unit 19 AD	1.2-6	63-01
XMC1DB2Y Unit 19 EH	1.2-6	63-01
XMC1DB2Y Unit 20 EH	1.2-6	63-01
XMC1DB2Y Unit 22 IM	1.2-6	63-01
Chillers		
XSW1DA1 Unit 7B	1.2-13	63-01
XSW1DA1 Unit 7C	1.2-13	63-01
XSW1DB1 Unit 6A	1.2-6	63-01
XSW1DB1 Unit 7A	1.2-6	63-01
Diesel Generator Fuel Oil Transfer Pumps		
XMC1DA2Z Unit 1 CD	1.2-12	36-01
XMC1DB2Z Unit 1 CD	1.2-12	36-02
HVAC System Fans		
XMC1DA2X Unit 2 AB	1.2-13	63-01
XMC1DA2X Unit 2 CD	1.2-13	63-01
XMC1DA2X Unit 2 EF	1.2-13	63-01
XMC1DA2X Unit 9 IJ	1.2-13	63-01
XMC1DA2X Unit 10 EF	1.2-13	63-01

TABLE 7.4-1 (Continued)

SUMMARY OF LOCAL CONTROL STATIONS

Equipment/Local Control Station	Reference FSAR Figure No.	Plant Room No.
HVAC Systems Fans (Continued)		
XMC1DA2X Unit 11 EF	1.2-13	63-01
XMC1DA2X Unit 15 IJ	1.2-13	63-01
XMC1DA2Y Unit 7 AB	1.2-4	12-28
XMC1DA2Y Unit 7 CD	1.2-4	12-28
XMC1DA2Y Unit 14 JK	1.2-4	12-28
XMC1DA2Z Unit 4 GI	1.2-12	36-01
XMC1DA2Z Unit 4 JL	1.2-12	36-01
XMC1DB2X Unit 2 IJ	1.2-12	36-01
XMC1DB2X Unit 3 IJ	1.2-12	36-01
XMC1DB2X Unit 6 CD	1.2-12	36-01
XMC1DB2Y Unit 4 IJ	1.2-6	63-01
XMC1DB2Y Unit 5 IJ	1.2-6	63-01
XMC1DB2Y Unit 12 GH	1.2-6	63-01
XMC1DB2Y Unit 20 AB	1.2-6	63-01
XMC1DB2Y Unit 20 CD	1.2-6	63-01
XMC1DB2Y Unit 23 KL	1.2-6	63-01
XMC1DB2Y Unit 24 CD	1.2-6	63-01
XMC1DB2Z Unit 3 AC	1.2-12	36-02
XMC1DB2Z Unit 3 DF	1.2-12	36-02
XMC1EA1X Unit 1 GI	1.2-24	25-05
XMC1EB1X Unit 4 JK	1.2-24	41-01
XPN0040 (Motor Control Panel)	1.2-3	88-13NE

TABLE 7.4-2

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings[1] FSAR Figure	Drawing Number	
Systems Required for Safe Shutdown					
	Component Cooling Water System	7.1, 7.1.2.6, 7.3.1.1,	7.3-1	-	
		7.3.1.1.5, 7.4, 7.5.4,	9.2-4 thru	-	
		9.2.2.1, 9.2.2.2,	9.2-7	-	
		9.2.2.3, 9.2.2.5,	-	B-208-005	
		11.4.2	-	B-208-011	
		Note 3			
	Diesel Generator Systems	7.3.1.1, 7.4, 8.3.1.1.2,	8.2-3	-	
		9.5.4.2, 9.5.4.3, 9.5.4.5,	8.3-Oh thru	-	
		9.5.5.3, 9.5.5.5, 9.5.6.1,	8.3-0j	-	
		9.5.7.3, 9.5.7.5, 9.5.8.3	9.5-2		
			9.5.3		
			9.5-4		
		Notes 3, 6	9.5-6		
			9.5-7		
			-	B-208-005	
			-	B-208-023	
	Emergency Feedwater System	7.1, 7.3.1.1, 7.3.1.1.5,	7.3-1	-	
		7.5.4, 10.4.9.2, 10.4.9.3,	10.4-16	-	00-01
		10.4.9.5	-	B-208-032	
				8756D01 (1MS-51-221)	99-01
		Note 6	-		

TABLE 7.4-2 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings[1] FSAR Figure	Drawing Number	
Systems Required for Safe Shutdown (Continued)	Service Water System	7.1, 7.1.2.6, 7.3.1.1,	7.3-1	-	
		7.3.1.1.5, 7.4, 7.5.4,	9.2-1	-	
		9.2.1.2, 9.2.1.3, 9.2.1.5	9.2-2	-	
		Note 3	-	B-208-005	
			-	B-208-101	
			-	8756D01 (1MS-51-221)	99-01
	Chilled Water System	7.1.2.6, 7.3.1.1, 7.3.1.1.5	7.3-1	-	
		7.5.4, 9.4.7.2.4, 9.4.7.3	9.4-22	-	
			9.4-23	-	
			9.4-24	-	
			-	B-208-005	
			-	B-208-109	
			-	8756D01 (1MS-51-221)	99-01
	Main Steam System	6.2.4, 7.3.1.1, 7.5.4.	10.3-1	-	
		7.7.1.8, 10.3, 10.3.1.2,	10.4-3		00-01
		10.4.9.2, 10.4.4.2,	10.4-4		
			-	B-208-063	
		Table 6.2-54	-	B-208-067	
			-	108D932	
		Note 7	-	8756D01 (1MS-51-221)	99-01

TABLE 7.4-2 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings(1) FSAR Figure	Related Drawings(1) Drawing Number	
Systems Required for Safe Shutdown (Continued)	Heating Ventilation and Air Conditioning Systems				
	Auxiliary and Fuel Handling Building Ventilation Systems	6.5.1.3, 6.5.1.5.3, 7.3.1.1, 7.3.1.1.5, 9.4.2.1, 9.4.2.2, 9.4.2.3, 9.4.3.2, 9.4.3.3	7.3-1	-	
			9-4-10	-	
			9.4-11	-	
		Notes 3, 6		B-208-004, Sh AH174, AH175	
			-	B-208-108, Sh VL05 thru VL09	
			-	8756D01 (1MS-51-221)	99-01
	Control Building Ventilation Systems	6.4, 6.4.1.5, 6.5.1.3, 6.5.1.5.2, 7.3.1.1, 7.3.1.1.5, 9.4.1.2, 9.4.1.3, 12.2.4.2.1	9.4-1	-	
			9.4-2	-	
			9.4-3	-	
			9.4-5	-	
		Note 6	-	B-208-004, Sh AH102 thru AH105, AH107, AH108, AH147, AH148	
			-	8756D01 (1MS-51-221)	99-01
	Diesel Generator Building Ventilation System	7.3.1.1.5, 8.3.1.1.2.4, 9.4.7.2.1, 9.4.7.3	9.4-18	-	
		Notes 3, 6	-	B-208-004, Sh AH164 thru AH167	

TABLE 7.4-2 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings[1] FSAR Figure	Drawing Number	
Systems Required for Safe Shutdown (Continued)	Intermediate Building Ventilation System	7.3.1.1, 7.3.1.1.5, 9.4.6.2, 9.4.6.3	9.4-15 thru 9.4-17	-	
				-	
			-	B-208-004, Sh AH194 thru AH197	
			-	B-208-108, Sh VL18, VL19, VL22, VL24, VL26, VL27, VL30, VL31	
			-	8756D01 (1MS-51-221)	99-01
	Reactor Building Ventilation System	6.2.2.2.2.1, 6.2.2.2.2.2, 6.2.2.5.2.2, 7.1.2.6, 7.3.1.1, 7.3.1.1.5, 7.5.4, 9.2.1.5, 9.4.7.2.5	6.2-49	-	
			7.3-1	-	
				B-208-004, Sh AH273 thru AH276	
		Notes 3, 6	-	8756D01 (1MS-51-221)	99-01
	Service Water Pumphouse Ventilation System	7.3.1.1.5, 9.4.7.2.2, 9.4.7.3	9.4-19	B-208-004 Sh AH326 thru 331	
			-		
			-	8756D01(1MS-51-221)	99-01
	Boric Acid Transfer Pumps	7.4.1.2.2, 9.3.4.2.3, 9.3.4.2.5.3	9.3-16 Sh 15	B-208-021 Sh CS-01	
		Tables 9.3-5, 7.1-2			
		Notes 3, 4			

TABLE 7.4-2 (Continued)

INSTRUMENT AND CONTROL DATA CROSS REFERENCES

Category	System	Reference FSAR Sections	Related Drawings[1] FSAR Figure	Drawing Number
Systems Required for Safe Shutdown (Continued)	CREP Monitoring Indicators	7.4.1.1 Table 7.1-2 Notes 2, 3, 5	7.2-1 Sh 11, and 13	-
	Charging Pumps	6.3.2.2.4.2, 6.3.2.2.7, 6.3.2.11.1, 7.1.2.5, 7.3.1.1, 7.3.1.1.5 Tables 7.3-1, 7.3-3, 8.3-36.3-7 Note 3	6.3-1 Sh 1 7.3-1	B-208-021 Sh CS.04 thru 08

<u>NOTES TO TABLE 7.4-2</u>

1. FSAR figure numbers refer to figures in the FSAR; drawing numbers refer to drawings in the Wiring Schematic Package (see Section 1.7).

2. Not redundant.

3. Not diverse.

4. Motor control center is the actuation device.

5. Indicators are the actuation device.

6. No interlocks or bypasses are provided which would inhibit ESF actuation.

7. The Main Stream System components required for safe shutdown include only the main stream isolation valves, and valves that emit steam to the turbine driven emergency feedwater pump. The steam generator power operated relief valves are safety class, seismic, air operated, fail closed valves. The valves can be manually opened if required for safe shutdown.

Figure 7.4-1, Sheet 2 - (Deleted per RN 99-074)
Figure 7.4-1, Sheet 3 - (Deleted per RN 99-074) 00-01

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CONTROL ROOM EVACUATION PANEL
IDENTIFICATION OF DEVICES

ITEM	DEVICE	DESCRIPTION
A	Indicator	TI-430A RCS Cold Leg Temp
B	Dual Indicator	LI-459B PZR Level/PI-455A PZR Press
C	Dual Indicator	NI-36A/Intermediate Range/NI-32A Source Range
D	Indicator	FI-150A LTDN Flow
E	Indicator	FI-122B Charging Flow
F	Indicator	PI-121A Charging Press
G	Indicator	FI-110A Emergency Borate Flow
H	Indicator	TI-433A RCS Hot Leg Temp
I	Indicator	TI-410A RCS Cold Leg Temp
J	Indicator	TI-423A RCS Hot Leg Temp
K	Dual Indicator	PI-2010A S/G B Press/LI-487B S/G B Level
L	Indicator	TI-413A RCS Hot Leg Temp
M	Dual Indicator	PI-2020A S/G C Press/LI-497B S/G C Level
N	Dual Indicator	LI-161A BA Tank Level/LI-163A BA Tank Level
O	Indicator	TI-420A RCS Cold Leg Temp
P	Dual Indicator	TI-9203B RB Temp/LI-3631B Condensate Tk Level
Q	Dual Indicator	PI-2000A S/G A Press/LI-477B S/G A Level
R	Control Switch	SS-RC08 PZR Heaters Backup Group 1
S	Control Switch	SS-RC09 PZR Heaters Backup Group 2
T	Controller	HC-122 Chg Flow - FCV 122
U	Control Switch	SS-CS09A Emer Borate - MVT 8104
V	Controller	HC-3536B TDEFP to S/GA
W	Controller	HC-3531B MDEFP to S/GA
X	Controller	HC-3546B TDEFP to S/GB
Y	Controller	HC-3551B MDEFP to S/GB
Z	Controller	HC-3556B TDEFP to S/GC
AA	Controller	HC-3541B MDEFP to S/GC
AB	XFER Switch	43-RC08 PZR Htr Group 1
AC	XFER Switch	43-RC09 PZR Htr Group 2
AD	XFER Switch	43-122 Chg Flow XFER
AE	XFER Switch	43-CS09 Emer Borate XFER
AF	XFER Switch	43-EFT TDEFP XFER
AG	XFER Switch	43-EFM MDEFP XFER
AH	Control Switch	SS-459 LCV-459 LTDN Isol
AI	Control Switch	SS-445A PZR Power Relief
AJ	Control Switch	SS-460 LCV-460 LTDN Isol
AK	Control Switch	SS-8149A LTDN Orifice Isol
AL	Control Switch	SS-8149B LTDN Orifice Isol
AM	Control Switch	SS-8149C LTDN Orifice Isol
AN	Control Switch	SS-2030 Stm Supply to EF Turb
AO	XFER Switch	43-445A PZR Power Relief
AP	Controller	HC-2034B EF Turb Speed Control
AQ	Control Switch	SS-SW01 SW Pump A
AR	Control Switch	SS-SW03 SW Pump C
AS	Control Switch	SS-SW04 SW Pump C
AT	Control Switch	SS-SW02 SW Pump B
AU	XFER Switch	43-459 LTDN Isol XFER
AV	XFER Switch	43-460 LTDN Isol XFER
AW	XFER Switch	43-8149A LTDN Orifice Isol XFER
AX	XFER Switch	43-8149B LTDN Orifice Isol XFER
AY	XFER Switch	43-8149C LTDN Orifice Isol XFER
AZ	XFER Switch	43-2030 Stm Supply to EF Turb
BA	XFER Switch	43-2034 EF Turb Speed Control
BB	XFER Switch	43-SW01 SW Pump A XFER
BC	XFER Switch	43-SW03 SW Pump C XFER
BD	XFER Switch	43-SW04 SW Pump C XFER
BE	XFER Switch	43-SW02 SW Pump B XFER
BF	Control Switch	SS-CS02A BA Transfer Pump B
BG	XFER Switch	43-CS02 BA Transfer Pump XFER
BH	Control Switch	SS-444B PZR Power Relief
BI	Dual Indicator	PI-403A RCS Press/PI-402D RCS Press
BJ	XFER Switch	43-444B PZR Power Relief
BK	Control Switch	SS-8152 LTDN Isol
BL	XFER Switch	43-8152 LTDN Isol
BM	Dual Indicator	LI-112 V.C.T. Level/LI-470A PZR RT Level
BN	XFER Switch	43-TSCA TSC Indicator XFER
BO	XFER Switch	43-TSCB TSC Indicator XFER

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

Control Room Evacuation Panel
(XPN-7200-CE(A&B))

Figure 7.4-2

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DECEMBER 2000

7.5 SAFETY RELATED DISPLAY INSTRUMENTATION

7.5.1 DESCRIPTION

Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident", provides guidance for selection of readouts to monitor plant variables and systems during and following a design basis event. For VCSNS, the post-accident monitoring instrumentation provides readouts to the operator to enable him to perform manual safety functions and to determine the effect of manual actions taken following a reactor trip due to a Condition II, III, or IV event, as defined in Chapter 15. This instrumentation and its associated design criteria are defined in the VCSNS Design Basis Document for Environmental Qualification/Regulatory Guide 1.97 Equipment. Regulatory Guide 1.97 instrumentation includes the readouts required to maintain the plant in a hot shutdown condition or to proceed to cold shutdown within the limits of the Technical Specifications. Reactivity control after Condition II and III faults will be maintained by administrative sampling of the reactor coolant for boron to ensure that the concentration is sufficient to maintain the reactor subcritical.

Table 7.5-2 lists the information available to the operator in addition to Regulatory Guide 1.97 instrumentation for monitoring conditions in the reactor, the Reactor Coolant System, and in the Reactor Building and process systems throughout all normal operating conditions of the plant, including anticipated operational occurrences.

7.5.2 ANALYSES

This section deleted by Amendment No. 94-08 in October, 1994.

7.5.3 DESIGN CRITERIA

This section deleted by Amendment No. 94-08 in October, 1994.

7.5.4 ESF MONITOR LIGHTS

Certain pumps and valves, which are an integral part of or which are associated with the engineered safety features systems (used for safety injection, Reactor Building spray, and recirculation) are equipped with ESF monitor lights. These "bright/dim" lights are displayed on the main control board within easy view of the operator. When the plant is in normal full power operation, the ESF monitor lights should generally be "dim." These lights change to the "bright" condition when the component monitored changes to an off normal operating mode. In addition to the ESF monitor lights, certain valves have an annunciator which indicates a change to an off-normal operating mode and actuates an alarm.

The ESF monitor lights are arranged on the main control board as shown by Figures 7.5-1 through 7.5-6 to permit the operator to discover easily a component that is in an off-normal operating mode. These figures also outline the components monitored. Elementary diagrams (GAI Dwg. B-208-066), submitted separately in the "Wiring Schematic Package" and listed in Table 1.7-1, outline the specific components included.

The ESF monitor lights provide supplemental information with regard to the status of ESF components.

7.5.5 INADEQUATE CORE COOLING

The inadequate core cooling instrumentation includes the Incore Temperature Monitoring System, the core subcooling monitors, and the Reactor Vessel Level Instrumentation System (RVLIS). Detailed descriptions of these systems and their design bases are provided in the Design Basis Document for Miscellaneous I&C. Compliance of these systems with Regulatory Guide 1.97, Rev. 3, is discussed in the VCSNS Design Basis Document for Environmental Qualification/Regulatory Guide 1.97 Equipment

TABLE 7.5-2

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
1. Source Range						
a. Count rate	2	1 to 10^6 counts/sec -0.5 to 5.0 decades/min	± 5.3% of the linear full scale analog voltage	Both channels indicated. Either may be selected for recording.	Control board	One 2 pen recorder is used to record any of the 8 nuclear channels (2 source range, 2 intermediate range, and 4 power range).
b. Startup rate	2	-0.5 to 5.0 decades/min	± 7% of the linear full scale analog voltage	Both channels indicated	Control board	
2. Power Range						
a. Uncalibrated ion chamber current (top and bottom uncompensated ion chambers)	4	0 to 120% of full power current	± 1% of full power current	All 8 current signals indicated.	NIS racks in control room	

TABLE 7.5-2 (Continued)

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated, Accuracy [1]	Indicator / Recorder	Location	Notes
2. Power Range (continued)						
b. Calibrated ion chamber current (top and bottom uncompensated ion chambers)	4	0 to 125% of full power current	± 2% of full power current	All 8 current signals recorded (four 2 pen recorders) Recorder 1 upper currents for two diagonally opposed detectors Recorder 2 - upper currents for remaining detectors Recorder 3 - lower currents for two diagonally opposed detectors Recorder 4 - lower currents for remaining detectors.	Control board	

TABLE 7.5-2 (Continued)

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated, Accuracy [1]	Indicator / Recorder	Location	Notes
2. Power Range (continued)						
c. Upper and lower ion chamber current difference	4	-30 to +30%	± 3% of full power current	Diagonally opposed channels may be selected for recording at the same time using recorder in Item 1.	Control board	00-01
d. Average flux of the top and bottom ion chamber	4	0 to 120% of full power	± 3% of full power for indication. ± 2% for recording	All 4 channels indicated. Any 2 of the four channels may be recorded using recorder in Item 1 above	Control board	
e. Average flux of the top and bottom ion chambers	4	0 to 200% of full power	± 2% of full power to 120% ± 6% of full power to 200%	All 4 channels recorded	Control board	
f. Flux difference of the top and bottom ion chambers	4	- 30 to + 30%	± 4%	All 4 channels indicated.	Control board	

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TABLE 7.5-2 (Continued)

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
REACTOR COOLANT SYSTEM						
1. $T_{average}$ (measured)	1/loop	530 to 630°F	± 4% F	All channels indicated.	Control board	
2. Overpower ΔT Setpoint	1/loop	0 to 150% of full power ΔT	± 4% of full power ΔT	All channels indicated. One channel is selected for recording.	Control board	
3. Overpower ΔT Setpoint	1/loop	0 to 150% of full power ΔT	± 4% of full power ΔT	All channels indicated. One channel is selected for recording.	Control board	
4. Overtemperature ΔT Setpoint	1/loop	to 150% of full power ΔT	± 4% of full power ΔT	All channels indicated. One channel is selected for recording.	Control board	
5. Primary Coolant Flow	3/Loop	0 to 120% of rated flow	Repeatability of ± 4.5% of full flow	All channels indicated.	Control board	

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TABLE 7.5-2 (Continued)

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated, Accuracy [1]	Indicator / Recorder	Location	Notes
REACTOR CONTROL SYSTEM						
1. Demanded Rod Speed	1	0 to 100% of rated speed	± 2%	The one channel is indicated.	Control board	
2. Median T_{avg}	1	530 to 630°F	± 4°F	The one channel is recorded.	Control Board	
3. $T_{reference}$	1	540 to 590°F	± 4°F	The one channel is recorded.	Control board	
4. Control rod Position						If system not available, borate and sample accordingly.
a. Number of steps of demanded rod withdrawal	1/group	0 to 230 steps	± 1 step	Each group is indicated during rod motion.	Control board	These signals are used in conjunction with the measured position signals (Item 4c) to detect deviation of any individual rod from the demanded position. A deviation will actuate an alarm and annunciator.
b. Demanded position of the part length rod bank	1	0 to 230 steps	± 1 step	The bank is indicated during rod motion.	Control board	

TABLE 7.5-2 (Continued)

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated, Accuracy [1]	Indicator / Recorder	Location	Notes
REACTOR CONTROL SYSTEM (Continued)						
5. Control rod Bank Demanded Position	4	0 to 230 steps	± 2.5% of total bank travel	All 4 control rod bank positions are recorded along with the low-low limit alarm for each bank.	Control board	1. One channel for each control bank. 2. An alarm and annunciator is actuated when the last rod control bank to be withdrawn reaches the withdrawal limit, when any rod control bank reaches the low-low insertion limit.
FEEDWATER AND STEAM SYSTEMS						
1. Programmed Steam Generator Level Signal	1/steam generator	0 to 100% of span	± 4%	All channels indicated.	Control board	
2. Steam Flow	2/steam generator	0 to 120% of max. calculated flow	± 5.5%	All channels indicated. The channels used for control are recorded.	Control board	Accuracy is equipment capability; however, absolute accuracy depends on applicant calibration against flow.

TABLE 7.5-2 (Continued)

CONTROL ROOM INDICATORS AND/OR RECORDERS AVAILABLE TO THE OPERATOR TO MONITOR SIGNIFICANT PLANT PARAMETERS DURING NORMAL OPERATION

Parameter	No. of Channels Available	Range	Indicated, Accuracy (1)	Indicator / Recorder	Location	Notes
FEEDWATER AND STEAM SYSTEMS (Continued)						
3. Steam Dump Modulate Signal	1	0 to 85% max. calculated steam flow	± 1.5%	The one channel is indicated	Control board	OPEN/SHUT indication is provided in the control room for each steam dump valve.
4. Turbine First Stage Pressure	2	0 to 120% of max. calculated turbine load	± 3.5%	Both channels indicated.	Control board	OPEN/SHUT indication is provided in the control room for each turbine stop valve.
COMPONENT COOLING WATER SYSTEM						
1. Reactor Coolant Pump Upper and Lower Bearing Cooling Water Flow	2	0 to 500 gpm	± 5.0% of calibrated span	Both channels indicated.	Control board	
2. Reactor Coolant Pump Thermal Barrier Cooling Water Flow	2	0 to 150 gpm	± 5.0% of calibrated span	Both channels indicated.	Control board	

(1) Includes channel accuracy and environmental effects.

7.6 ALL OTHER SYSTEMS REQUIRED FOR SAFETY

7.6.1 INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEM

7.6.1.1 Description

The following is a description of the Instrumentation and Control Power Supply System:

1. Refer to Figures 8.3-1, 8.3-2, 8.3-2aa, and 8.3-2ab for a single line diagram of the Instrumentation and Control Power Supply System.

2. There are 4 inverters and 6 distribution panels. Four (4) normally operating inverters are connected to 4 distribution panels. The remaining 2 panels are branch loads of the same channelized distribution panel.

3. The inverters provide a source of 120 volt 60 Hz power for the operation of the Nuclear Steam Supply System instrumentation. This power is derived from the 480 volt a-c, 3∅, 60 Hz distribution system Class 1E power supply, or the station batteries which assure continued operation of instrumentation systems in the event of loss of offsite power. 99-01

4. Each of the 4 distribution panels fed from the 4 normally operating inverters may be connected to a backup regulated source of 120 volt Class 1E a-c power. The tie is through an automatic static transfer switch or through a manual bypass switch such that the distribution panel cannot be connected to both sources simultaneously.

7.6.1.2 Analysis

There are 2 independent 480 volt a-c power sources, each serving 2 inverters. Therefore, loss of either of the two 480 volt a-c power sources affects only 2 of the 4 inverters.

There are 2 independent Class 1E batteries and battery chargers. Each battery is attached to a bus serving 2 inverters.

There is a third battery charger provided, which serves as a standby charger. This charger is provided for use during maintenance of, and backup to the normal battery chargers. The standby charger has mechanically interlocked circuit breakers on the a-c input and d-c output such that only the 2 circuit breakers associated with Channel A or the 2 circuit breakers associated with Channel B can close at one time.

Since not more than 2 inverters are connected to the same bus, a loss of a single bus can only affect 2 of the 4 inverters.

Since each of the 4 instrument channels is supplied power by independently connected inverters, the loss of an inverter cannot affect more than 1 of the 4 instrument channels.

Each distribution panel can receive power from the 120 volt Class 1E a-c backup regulated source through an automatic static transfer switch or through a manual bypass switch. The inverter power source and the backup source are aligned such that the distribution panels cannot be connected to both sources at the same time.

Therefore no single failure in the Instrumentation and Control Power Supply System or its associated power supplies can cause a loss of power to more than one of the redundant loads.

The inverters are designed to maintain their outputs within acceptable limits. The loss of the a-c or d-c inputs is alarmed in the Control Room, as is the loss of an inverter's output. There are no inverter breaker controls on the control board, as no manual transfers are necessary in the event of loss of the 480 volt a-c preferred power source. The a-c and d-c inputs are diode isolated in the UPS.

Physical separation and provisions to protect against fire are discussed in Chapter 8.

Based on the scope definitions presented in References [1] through [3], the criteria which are applicable to the Instrumentation and Control Power Supply System are listed in IEEE Standard 308-1971. The design is in compliance with IEEE Standard 308-1971 and Regulatory Guide 1.6. Availability of this system is continuously indicated by the operational status of the systems it serves (see Figures 8.3-1 and 8.3-2) and is verified by periodic testing performed on the served systems. The inverters have been seismically qualified as discussed in Section 3.10 and shown in Table 3.10-2.

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7.6.2 RESIDUAL HEAT REMOVAL ISOLATION VALVES

7.6.2.1 Description

There are 2 motor operated gate valves in series in each of 2 inlet lines from the Reactor Coolant System to the Residual Heat Removal System. They are normally closed and are only opened for residual heat removal and Reactor Coolant System overpressure protection after system pressure is reduced below approximately 425 psig and system temperature has been reduced to approximately 350°F (see Chapter 5). They are the same type of valve and motor operator as those used for accumulator isolation (refer to Section 7.6.4), but they differ in their controls indications in the following respect (see Figures 7.6-1, 7.6-1a, and 7.6-1b):

1. Pressure interlocks are provided to prevent opening of the isolation valves whenever the Reactor Coolant System pressure is greater than approximately 425 psig. This interlock is derived from Class 1E process instrumentation channel for the isolation valves closest to the Reactor Coolant System (XVG8702A and XVG8702B) and from another independent process instrumentation channel for

the 2 isolation valves closest to the Residual Heat Removal System (XVG8701A and XVG8701B). Interlock diversity is provided through the use of pressure transmitters from different manufacturers employing different measurement principles for the 2 channels of process instrumentation.

2. In addition to the open interlock, an alarm is located in the Control Room which will alert the operator if these valves are not fully closed when the Reactor Coolant System pressure increases above the 520 psig alarm setpoint.

7.6.2.2 Analysis

Based on the scope definitions presented in References [2] and [3], these criteria do not apply to the residual heat removal isolation valve interlocks; however, in order to meet NRC requirements and because of the possible severity of the consequences of loss of function, the requirements of IEEE Standard 279-1971 will be applied with the following comments:

1. For the purpose of applying IEEE Standard 279-1971, to this circuit, the following definitions will be used.

    a. Protection System

       The 2 valves in series in each line and all components of their interlocks that prevent opening of the isolation valves whenever the Reactor Coolant System pressure is greater than 425 psig.

    b. Protective Action

       The maintenance of Residual Heat Removal System isolation from the Reactor Coolant System when Reactor Coolant System pressures are above the preset value.

2. IEEE Standard 279-1971, paragraph 4.10: The above mentioned pressure interlock signals and logic will be tested on line to the maximum extent possible without adversely affecting safety. This test will include the analog signal through to the train signal which activates the relays that provide the interlocks into the valve control circuit. This is done in the best interests of safety since defeat of the interlock to permit opening the valve could potentially leave only 1 remaining valve to isolate the low pressure Residual Heat Removal System from the Reactor Coolant System.

   It is noted that the valve position lights operated from the motor operated valve limit switch on the operator are similar to the position lights (red for open and green for closed) for the accumulator isolation valves described in Section 7.6.4.

3. IEEE Standard 279-1971, paragraph 4.15: This requirement does not apply, as the setpoints are independent of mode of operation and are not changed.

Environmental qualification of the valves and wiring is discussed in Section 3.11.

7.6.3 REFUELING INTERLOCKS

Electrical interlocks (i.e., limit switches) as discussed in Section 9.1.4 are provided for minimizing thé possibility of damage to the fuel during fuel handling operations.

7.6.4 ACCUMULATOR MOTOR OPERATED VALVES

The design of the interconnection of signals to open the accumulator isolation valves meets the following criteria established in previous NRC positions on this matter:

1. Automatic opening of the accumulator valves when a) the primary coolant system pressure exceeds a preselected value (specified in the Technical Specifications) or b) as a safety injection signal has been initiated. Both signals shall be provided to the valves.

2. Utilization of a safety injection signal to automatically remove (override) any bypass features that are provided to allow an isolation valve to be closed for short periods of time when the Reactor Coolant System is at pressure (in accordance with the provisions of the Technical Specifications). As a result of the confirmatory "S" signal, isolation of an accumulator with the Reactor Coolant System at pressure is acceptable.

The control circuit for these valves is shown on Figure 7.6-2. The valves and control circuits are further discussed in Sections 6.3.2.15 and 6.3.5.

The Safety Injection System accumulator discharge isolation valves are motor operated normally open valves which are controlled from the main control board. These valves are interlocked such that:

1. They open automatically on receipt of an "S" signal with the main control board switch in either the "AUTO" or "CLOSE" position.

2. They open automatically whenever the Reactor Coolant System pressure is above the safety injection unblock pressure (P-11) specified in the Technical Specifications only when the main control board switch is in the "AUTO" position.

3. They cannot be closed as long as an "S" signal is present.

The main control board switches for these valves are 3 position switches which provide a "spring return to auto" from the open position and a "maintain position" from the closed position.

The "maintain closed" position is required to provide an administratively controlled manual block of the automatic opening of the valve at pressure above the safety injection unblock pressure (P-11). The manual block or "maintain closed" position is required when performing periodic check valve leakage tests when Reactor Coolant System is at pressure. The maximum permissible time that an accumulator valve can be closed when the Reactor Coolant System is at pressure is specified in the Technical Specifications.

Administrative control is required to ensure that any accumulator valve, which has been closed at pressures above the safety injection unblock pressure, is returned to the "AUTO" position. Verification that the valve automatically returns to its normal full open position would also be required.

During plant shutdown, the accumulator valves are in a closed position. To prevent an inadvertent opening of these valves during that period the accumulator valve breakers should be opened or removed. Administrative control is again required to ensure that these valve breakers are closed during the prestartup procedures.

7.6.5 LEAKAGE DETECTION SYSTEMS

7.6.5.1 <u>Description</u>

Leakage detection is provided for the following areas and systems:

1. Reactor coolant pressure boundary (see Section 5.2.7 for a detailed description).

2. Engineered safety features systems (i.e., Reactor Building Spray, Residual Heat Removal, Safety Injection systems) in the Auxiliary Building.

3. Feedwater system (intermediate building flood protection).

7.6.5.1.1 Engineered Safety Features Systems in the Auxiliary Building

1. Level

   Undetected leaks from the Engineered Safety Features Systems in the Auxiliary Building (Reactor Building Spray, Residual Heat Removal, Safety Injection) could have adverse effects upon the safety functions of these systems. For this reason, means for detecting leakage are provided.

   Level switches are located in specifically provided alarm drains and in the building drain sumps. When leakage exceeds a flowrate of 25 gpm for the floor drains or 45 gpm the sump drains, an alarm is activated in the Control Room. Upon receipt of such an alarm, the operator takes action to isolate the leak. 98-01 00-01

   Figures 9.3-6 and 9.3-7 schematically depict the locations of alarm drains and building sumps.

2. Temperature

Undetected leakage from the Chemical and Volume Control System letdown lines or the Auxiliary Steam System could cause the ambient temperature in the Auxiliary Building to rise. This high temperature could possibly prohibit personnel access to the area and limit the capability of equipment to function. Pipe rupture analysis has indicated the location of the most probable break areas in the system. Temperature sensors located in these break areas actuate alarms in the Control Room. Locations of these sensors are illustrated by Figures 7.6-3a through 7.6-8.

7.6.5.1.2 Feedwater System

Safety equipment and systems in the Intermediate Building are protected from flooding due to postulated pipe break or component failure resulting in leakage from the Feedwater System.

The sump level system incorporates a level switch located in each of the 3 Intermediate Building sumps. Should a high level occur in any sump, it is annunciated in the Control Room to alert the operator to the need for investigation of the source of leakage and, if necessary, to take manual action to isolate the leak. The high-high sump level detectors are set to detect flooding which occurs at a rate which exceeds the capacity of the sump pumps. When 2 out of 3 redundant high-high sump level switches are energized, the A channel closes the feedwater pump discharge valves and the B channel trips the feedwater pumps and closes the feedwater pump suction valves. The A channel closes the feedwater isolation valves to the steam generators.

7.6.5.1.3 Leak Detection Methods Inside the Control Room

Table 7.6-1 provides a tabulation of leak detection methods inside the Control Room.

7.6.5.2 <u>Analysis</u>

Leak detection instrumentation is seismically qualified. These instruments are located throughout the Auxiliary Building in areas where engineered safety features equipment and piping are located. Physical separation and separate electrical power sources are used for 2 sets of redundant instruments. Calibration of the Leak Detection System instrumentation can be performed during plant operation. The instrumentation can be functionally checked by testing at any time.

7.6.6 INTERLOCKS FOR RCS PRESSURE CONTROL DURING LOW TEMPERATURE OPERATION

This Section deleted by Amendment 1 in August, 1985.

7.6.7 SWITCHOVER FROM INJECTION TO RECIRCULATION

The details of achieving cold leg recirculation following safety injection and a postulated LOCA are given in Section 6.3.2.2.7 and on Table 6.3-3.

7.6.7.1 Description of Instrumentation Used for Switchover

As noted in Table 6.3-3, protection logic is provided to automatically open the 4 Safety Injection System (SIS), Reactor Building recirculation sump isolation valves (8811A and 8812A in Train A and 8811B and 8812B in Train B) when 2 of 4 (2/4) Refueling Water Storage Tank (RWST) level transmitters sense the Lo-Lo level setpoint in conjunction with the initiation of the engineered safety features actuation signal ("S" signal). The "S" signal is initiated by the contact of a slave relay in the Solid State Protection System output cabinet that closes on Safety Injection and remains closed until manually reset from the control board. This reset switch is separate from the main safety injection reset switch which is not associated with this circuit. The purpose of the sump valve automatic open circuit reset switch is to permit the operator to remove the actuation signal in the event the corresponding sump isolation valve must be closed and retained in a closed position following a LOCA, such as for maintenance purposes.

7.6.7.2 Initiating Circuit

The 2/4 Lo-Lo RWST level is the trip signal, which in coincidence with the "S" signal, provides the initiation function which would align the 2 residual heat removal pumps to take suction from the Reactor Building sumps and deliver directly to the RCS.

7.6.7.3 Logic

The logic function derived from the RWST level sensors and the "S" signal are depicted in Figure 7.6-9.

7.6.7.4 Bypass

The manual reset logic function is shown in Figure 7.6-10 and its purpose and action are described in Section 7.6.7.1. As noted, the "S" signal is retained by sealing it in (i.e., it is latched). This signal is not removed by action of the main safety injection reset that is used by the operator per emergency procedures to block the "S" signal to certain other equipment prior to realignment for switchover to the recirculation mode following a postulated loss of coolant accident.

7.6.7.5 Interlocks

The Trip Signal logic consists of 4 Refueling Water Storage Tank water level transmitters, each of which provides a level signal to 1 of the 4 Refueling Water Storage Tank level channel bistables. The Refueling Water Storage Tank level channel bistables are:

1. Normally de-energized

2. De-energized on loss of power

3. Energized on Lo-Lo setpoint

Each level channel bistable is assigned to a separate instrumentation and control power supply. A Trip Signal is provided from both Train A and Train B Solid State Protection System cabinets to the corresponding Reactor Building recirculation sump isolation valves logic, should 2 of the 4 water level channel bistables receive an RWST level signal lower than the Lo-Lo level setpoint, following the generation of an "S" signal.

7.6.7.6 Sequence

This circuit is energized directly from the Solid State Protection System output cabinet and is not sequenced following an accident that requires its functioning.

7.6.7.7 Redundancy

The function of this semi-automatic switchover is available from both Train A and Train B down to the actuated equipment. The function including the actuated equipment is, therefore, redundant and train separation and independence are maintained from sensor to actuated equipment.

7.6.7.8 Diversity

Diversity of components and equipment between the redundant Trains is not required to protect against systematic failures, such as multiple failures resulting from a credible single event. The associated components are environmentally and seismically qualified in accordance with the procedures described in Sections 3.10 and 3.11. It is noted that there is functional diversity provided in that manual operation is available as a backup to the semi-automatic mode.

7.6.7.9 Actuated Devices

The actuated devices are the 4 motor control center starters, 1 for each of the Motor Operated Sump Valves, 8811 A&B, and 8812 A&B.

7.6.7.10 Channel Bypass Indication

Indication is provided on the main control board to alert the operator that a Refueling Water Storage Tank water level channel is in the bypass mode and is unavailable. The indication is by status light and alarm window as shown on figure 7.6-10.

7.6.8 Deleted

7.6.9 Deleted

7.6.10 Deleted

7.6.11 SWITCHOVER FROM SPRAY TO RECIRCULATION

The details of the Reactor Building Spray System operation following a postulated loss of coolant accident are given in Section 6.2.2.2.1.2.

7.6.11.1 Description of Instrumentation Used for Switchover

As noted in Section 6.2.2.2.1.2 logic is provided to automatically open the 4 Reactor Building Spray System, Reactor Building recirculation sump isolation valves (3004A and 3005A in Train A and 3004B and 3005B in Train B) when 2 of 4 (2/4) Refueling Water Storage Tank (RWST) level transmitters sense the Lo-Lo level setpoint in conjunction with the initiation of the engineered safety features actuation signal ("S" signal). The "S" signal is initiated by the contact of a slave relay in the Solid State Protection System output cabinet that closes on safety injection and remains closed until manually reset from the control board. This reset switch is separate from the main safety injection reset switch which is not associated with this circuit. The purpose of the sump valve automatic open circuit reset switch is to permit the operator to remove the actuation signal in the event the corresponding sump isolation valve must be closed and retained in a closed position following a loss of coolant accident, such as for maintenance purposes.

7.6.11.2 Initiation Circuit

The 2/4 Lo-Lo Refueling Water Storage Tank level is the trip signal, which in coincidence with the "S" signal, provides the initiation function which would automatically align the 2 Reactor Building spray pumps to take suction from the Reactor Building recirculation sumps and deliver directly to the Reactor Building spray nozzles.

7.6.11.3 Logic

The logic function derived from the Refueling Water Storage Tank level sensors and the "S" signal are depicted in Figures 7.6-9 and 7.6-10.

7.6.11.4 Bypass

The manual reset logic function is shown in Figure 7.6-9 and its purpose and action are described in Section 7.6.11.1. As noted, the "S" signal is retained by sealing it in (i.e., it is latched). This signal is not removed by action of the main safety injection reset that is used by the operator per emergency procedures to block the "S" signal to certain other equipment prior to realignment for switchover to the recirculation mode following a postulated loss of coolant accident.

7.6.11.5 Interlocks

The Trip Signal logic consists of 4 Refueling Water Storage Tank water level transmitters, each of which provides a level signal to 1 of the 4 Refueling Water Storage Tank level channel bistables. The Refueling Water Storage Tank level channel bistables are:

1. Normally de-energized

2. De-energized on loss of power

3. Energized on Lo-Lo setpoint

Each level channel bistable is assigned to a separate instrumentation and control power supply. A Trip Signal is provided from both Train A and Train B Solid State Protection System cabinets to the corresponding Reactor Building recirculation sump isolation valves logic, should 2 of the 4 water level channel bistables receive an Refueling Water Storage Tank level signal lower than the Lo-Lo level setpoint, following the generation of an "S" signal.

7.6.11.6 Sequence

This circuit is energized directly from the Solid State Protection System output cabinet and is not sequenced following an accident that requires its functioning.

7.6.11.7 Redundancy

The function of this switchover is available from both Train A and Train B down to the actuated equipment. The function including the actuated equipment is, therefore, redundant and train separation and independence are maintained from sensor to actuated equipment.

7.6.11.8 Diversity

Diversity of components and equipment between the redundant Trains is not required to protect against systematic failures, such as multiple failures resulting from a credible single event. The associated components are environmentally and seismically qualified in accordance with the procedures described in Sections 3.10 and 3.11. It is noted that there is functional diversity provided in that manual operation is available as a backup to the semi-automatic mode.

7.6.11.9 Actuated Devices

The actuated devices are the 4 motor control center starters, 1 for each of the Motor Operated Sump Valves, 3004 A&B and 3005 A&B.

7.6.11.10 Channel Bypass Indication

Indication is provided on the main control board to alert the operator that a Refueling Water Storage Tank water level channel is in the bypass mode and is unavailable. The indication is by status light and alarm window as shown on Figure 7.6-10.

7.6.12 REFERENCES

1. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Criteria for Class 1E Electrical Systems for Nuclear Power Generating Stations," IEEE Standard 308-1971.

2. The Institute of Electrical and Electronic Engineers, Inc., "IEEE Standard: Criteria for Protection Systems for Nuclear Power Generating Stations," IEEE Standard 279-1971.

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TABLE 7.6-1

LEAK DETECTION METHODS
INSIDE CONTROL ROOM

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
Refueling water storage tank level	level transmitters (LT990, LT991, LT992, LT993)	indication alarm-high level	reactor coolant leakage to ECCS
Accumulator level	level transmitters (LT920, LT922, LT924, LT926, LT928, LT930)	indication alarm-high level	reactor coolant leakage to ECCS
Accumulator pressure	pressure transmitters (PT921, PT923, PT925, PT927, PT929, PT931)	indication alarm-high level	reactor coolant leakage to ECCS
Reactor vessel flange leak-off temperature	temperature element (TE401)	indication alarm-high temperature	leakage from reactor vessel
Pressurizer safety valve discharge temperature	temperature elements (TE463, TE465, TE467, TE469)	indication alarm-high temperature	reactor coolant leakage to pressurizer relief tank
Pressurizer relief tank temperature	temperature element (TE471)	indication alarm-high temperature	reactor coolant leakage to pressurizer relief tank
Pressurizer relief tank level	level transmitters (LT470)	indication alarm-high level	reactor coolant leakage to pressurizer relief tank
Flow in pressurizer relief line	acoustic leak monitor	alarm-high flow	reactor coolant leakage to pressurizer relief tank

TABLE 7.6-1 (Continued)

LEAK DETECTION METHODS
INSIDE CONTROL ROOM

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
Leak detection drains	level switches	alarm-high level	nuclear valve leak-off and miscellaneous equipment leakage
Steam generator blowdown and sampling radiation	radiation monitor (RM-L3, RM-L10)	indication alarm-high radiation	primary to secondary system leakage
Main plant vent exhaust radiation	radiation monitor (RM-A3)	indication alarm-high radiation	primary to secondary system leakage
Turbine room sump radiation	radiation monitor (RM-L8)	indication alarm-high radiation	primary to secondary system leakage
Component cooling water radiation	radiation monitor (RM-L2A, RM-L2B)	indication alarm-high radiation	intersystem leakage into component cooling water system
Component cooling water temperature from RHR heat exchanger	temperature elements (TE7037, TW7047) temperature switches (TS038, TS7048)	indication alarm-high temperature	residual heat removal heat exchanger leakage

TABLE 7.6-1 (Continued)

LEAK DETECTION METHODS
INSIDE CONTROL ROOM

PARAMETER	PRIMARY DETECTION ELEMENT	CONTROL ROOM DISPLAY	TYPE OF LEAKAGE
Component cooling water temperature from reactor coolant drain tank	temperature elements (TE7118)	indication alarm-high temperature	reactor coolant drain tank heat exchanger leakage
Component cooling water flow from reactor coolant drain tank	flow transmitters (FT7116)	indication	reactor coolant drain tank heat exchanger leakage
Component cooling water temperature from reactor coolant pump thermal barrier	temperature elements (TE7140, TE7160, TE7180)	indication alarm-high temperature	reactor coolant pump thermal barrier leakage
Component cooling water flow from reactor coolant pump thermal barrier	flow transmitters (FT7138, FT7158, FT7178)	indication	reactor coolant pump thermal barrier leakage

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The general design objectives of the plant control systems are:

1. To establish and maintain power equilibrium between primary and secondary system during steady-state unit operation;

2. To constrain operational transients so as to preclude unit trip and re-establish steady-state unit operation;

3. To provide the reactor operator with monitoring instrumentation that indicates required input and output control parameters of the systems and provides the operator the capability of assuming manual control of the system.

7.7.1 DESCRIPTION

The plant control systems described in this section perform the following functions:

1. Reactor Control System

   a. Enables the nuclear plant to accept a step load increase or decrease of 10% and a ramp increase or decrease of 5% per minute within the load range of 15% to 100% without reactor trip, steam dump, or pressurizer relief actuation, subject to possible xenon limitations.

   b. Maintains reactor coolant average temperature (T_{avg}) within prescribed limits by creating the bank demand signals for moving groups of full length rod cluster control assemblies during normal operation and operational transients. The T_{avg} control also supplies a signal to pressurizer water level control, and steam dump control.

2. Rod Control System

   a. Provides for reactor power modulation by manual or automatic control of full length control rod banks in a preselected sequence and for manual operation of individual banks.

   b. Systems for Monitoring and Indicating

      (1) Provide alarms to alert the operator if the required core reactivity shutdown margin is not available due to excessive control rod insertion.

      (2) Display control rod position.

      (3) Provide alarms to alert the operator in the event of control rod deviation exceeding a preset limit.

3. Plant Control System Interlocks

   a. Prevent further withdrawal of the control banks when signal limits are approached that predict the approach of a departure from nucleate boiling ratio (DNBR) limit or linear power (kW/ft) limit.

   b. Inhibit automatic turbine load change as required by the Nuclear Steam Supply System.

4. Pressurizer Pressure Control

   a. Maintains or restores the pressurizer pressure to the design pressure ± 50 psi 00-01
   (which is well within reactor trip and relief and safety valve actuation setpoint limits) following normal operational transients that induce pressure changes by control (manual or automatic) of heaters and spray in the pressurizer. Provides steam relief by controlling the power relief valves.

5. Pressurizer Water Level Control

   a. Establishes, maintains, and restores pressurizer water level within specified limits as a function of the average coolant temperature. Changes in level are caused by coolant density changes induced by loading, operational, and unloading transients. Level changes are controlled by means of charging flow control (manual or automatic) as well as by manual selection of letdown orifices. Maintaining coolant level in the pressurizer within prescribed limits by actuating the charging and letdown system thus provides control of the reactor coolant water inventory.

6. Steam Generator Water Level Control

   a. Establishes and maintains the steam generator water level to within predetermined physical limits during normal operating transients.

   b. Restores the steam generator water level to within predetermined limits at unit trip conditions. Regulates the feedwater flowrate such that under operational transients the heat sink for the reactor coolant system does not decrease below a minimum. Steam generator water inventory control is manual or automatic through the use of feedwater control valves.

7. Steam Dump Control

   a. Permits the nuclear plant to accept a sudden loss of load without incurring reactor trip. Steam is dumped to the condenser and/or the atmosphere as necessary to accommodate excess power generation in the reactor during turbine load reduction transients.

b. Ensures that stored energy and residual heat are removed following a reactor trip to bring the plant to equilibrium no load conditions without actuation of the steam generator safety valves.

c. Maintains the plant at no load conditions and permits a manually controlled cooldown of the plant.

7.7.1.1 Reactor Control System

The Reactor Control System enables the nuclear plant to follow load changes automatically including the acceptance of step load increase or decreases of 10% and ramp increases or decreases of 5% per minute within the load range of 15% to 100% without reactor trip, steam dump, or pressure relief (subject to possible xenon limitations). The system is also capable of restoring coolant average temperature to within the programmed temperature deadband following a change in load. Manual control rod operation may be performed at any time.

The Reactor Control System controls the reactor coolant average temperature by regulation of control rod bank position. The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. There is an average coolant temperature (T_{avg}) computed for each loop, where:

$$T_{avg} = \frac{T_{hot-avg} + T_{cold}}{2}$$

The error between the programmed reference temperature (based on turbine first stage pressure) and the median of the T_{avg} measured temperatures (which is processed through a lead/lag compensation unit) from each of the reactor coolant loops constitutes the primary control signal as shown in general on Figure 7.7-1 and in more detail on the functional diagrams shown in Figure 7.2-1, Sheet 9. The system is capable of restoring coolant average temperature to the programmed value following a change in load. The programmed coolant temperature increases linearly with turbine load from zero power to the full power condition. The T_{avg} also supplies a signal to pressurizer level control and steam dump control and rod insertion limit monitoring.

The temperature channels needed to derive the temperature input signals for the Reactor Control System are fed from protection channels via isolation amplifiers.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks.

7.7.1.2 Rod Control System

7.7.1.2.1 Full Length Rod Control System

The full length rod control system receives rod speed and direction signals from the T_{avg} control system. The rod speed signal by design may vary over the corresponding range of 5 to 45 inches per minute (6 to 72 steps/minute) depending on the magnitude of the input signal. Manual control is provided to move a control bank in or out at a prescribed fixed speed. 99-01 00-01

When the turbine load reaches approximately 15% of rated load, the operator may select the "AUTOMATIC" mode, and rod motion is then controlled by the Reactor Control Systems. A permissive interlock C-5 (see Table 7.7-1) derived from the measurements of turbine first stage pressure prevents automatic control when the turbine load is below 15%. In the "AUTOMATIC" mode, the rods are again withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming with the control interlocks (see Table 7.7-1).

The shutdown banks are always in the fully withdrawn position during normal operation, and are moved to this position at a constant speed by manual control prior to criticality. A reactor trip signal causes them to fall by gravity into the core. There are 2 shutdown banks.

The control banks are the only rods that can be manipulated under automatic control. Each control bank is divided into 2 groups to obtain smaller incremental reactivity changes per step. All rod control cluster assemblies in a group are electrically paralleled to move simultaneously. There is individual position indication for each rod cluster control assembly.

Power to rod drive mechanisms is supplied by 2 motor generator sets operating from 2 separate 480 volt, 3-phase buses. Each generator is the synchronous type and is driven by a 200 Hp induction motor. The a-c power is distributed to the rod control power cabinets through the 2 series connected reactor trip breakers. 99-01

The variable speed rod drive programmer affords the ability to insert small amounts of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing control at high speed. A summary of the rod cluster control assembly sequencing characteristics is given below:

1. Two (2) groups within the same bank are stepped such that the relative position of the groups will not differ by more than 1 step.

2. The control banks are programmed such that withdrawal of the banks is sequenced in the following order; control bank A, control bank B, control bank C, and control bank D. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank withdrawn (bank D) is the first control bank inserted.

3. The control bank withdrawals are programmed such that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank. When the first bank reaches the top of the core, it stops, while the second bank continues to move toward its fully withdrawn position. When the second bank reaches a preset position, the third bank begins to move out, and so on. This withdrawal sequence continues until the unit reaches the desired power level. The control bank insertion sequence is the opposite.

4. Overlap between successive control banks is adjustable between 0 to 50% (0 to 115 steps), with an accuracy of ± 1 step.

5. Rod speeds for either the shutdown banks or manual operation of the control banks are capable of being controlled between a minimum of 8 steps per minute and a maximum of 72 (+ 0 steps per minute, - 10 steps per minute) steps per minute. 00-01

7.7.1.2.2 Part Length Rod Control System

The part length control rods have been deleted.

7.7.1.3 Plant Control Signals for Monitoring and Indicating

7.7.1.3.1 Monitoring Functions Provided by the Nuclear Instrumentation System

The power range channels are important because of their use in monitoring power distribution in the core within specified safe limits. They are used to measure power level, axial power imbalance, and radial power imbalance. The channels are capable of recording overpower excursions up to 200% of full power. Suitable alarms are derived from these signals as described below.

Basic power range signals are:

1. Total current from a power range detector (4 such signals from separate detectors); these detectors are vertical and have a total active length of 10 feet.

2. Current from the upper half of each power range detector (4 such signals).

3. Current from the lower half of each power range detector (4 such signals).

Derived from these basic signals are the following (including standard signal processing for calibration).

4. Indicated nuclear power (4 such signals).

5. Indicated axial flux imbalance, derived from upper half flux minus lower half flux (4 such signals).

Alarm functions derived are as follows:

6. Deviation (maximum minus minimum of 4) in indicated nuclear power.

7. Upper radial tilt (maximum to average of 4) on upper-half currents.

8. Lower radial tilt (maximum to average of 4) on lower-half currents.

Provision is made to continuously record, on strip charts on the control board, the 8 ion chamber signals, i.e., upper and lower signals for each detector. Nuclear power and axial unbalance is selectable for recording as well.

The axial flux difference imbalance deviation $\Delta\Phi$ alarms are derived from the plant process computer which determines the one minute averages of the excore detector outputs to monitor $\Delta\Phi$ in the reactor core and alerts the operator where $\Delta\Phi$ alarm conditions exist. Two (2) types of alarm messages are output. Above a preset (90%) power level, an alarm message is output immediately upon determining a delta flux exceeding a preset band (usually ± 5%) about a target delta flux value. Below this preset power level, an alarm message is output if the $\Delta\Phi$ exceeded its allowable limits for a preset cumulative (usually 1 hour) amount of time in the past 24 hours.

Additional background information on the Nuclear Instrumentation System can be found in Reference [1].

7.7.1.3.2 Rod Position Monitoring of Full and Part Length Rods

Two (2) separate systems are provided to sense and display control rod position as described below:

1. Digital Rod Position Indication System

   The Digital Rod Position Indication System displays full length and part length rod position. Part length rods and control are not used at V. C. Summer Nuclear Station. The part length rod positions are shown on the display, but are inactive. 98-01
   The Digital Rod Position Indication System senses the actual position of each full length rod using a detector which consists of discrete coils mounted concentrically with the rod drive pressure housing. The coils are located axially along the

pressure housing and magnetically sense the entry and presence of the rod drive shaft through its center line. For each detector, the coils are interlaced into 2 data channels, and are connected to the containment electronics (Data A and B) by separate multi-conductor cables. By employing 2 separate channels of information, the Digital Rod Position Indication System can continue to function (at reduced accuracy) when 1 channel fails. Multiplexing is then used to transmit the digital position signals from the containment electronics to the control board display unit.

The control board display unit contains a column of light-emitting-diodes (LEDs) for each rod. At any given time, the LEDs illuminated in each column shows the position for that particular rod. Each rod in the control banks and Shutdown banks has its position displayed to ± 4 steps throughout its range of travel. 00-01

Included in the system is a rod at bottom signal for each rod that operates a local alarm. Also a control room annunciator is actuated when any shutdown rod or control bank A rod is at bottom.

2. Demand Position System - The Demand Position System counts pulses generated in the Rod Drive Control System to provide a digital readout of the demanded bank position. 98-01

   The Demand Position and Digital Rod Position Indication Systems are separate systems, but safety criteria were not involved in the separation, which was a result only of operational requirements. Operating procedures require the reactor operator to compare the demand and indicated (actual) readings from the Rod Position Indication System so as to verify operation of the Rod Control System.

7.7.1.3.3 Control Bank Rod Insertion Monitoring

When the reactor is critical, the normal indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by the Reactor Coolant System loop ΔT) and coolant average temperature. These parameters are used to calculate insertion limits for the control banks. Two (2) alarms are provided for each control bank:

1. The "low" alarm alerts the operator of an approach to the rod insertion limits requiring boron addition by following normal procedures with the Chemical and Volume Control System.

2. The "low-low" alarm alerts the operator to take immediate action to add boron to the Reactor Coolant System by any one of several alternate methods.

The purpose of the control bank rod insertion monitor is to give warning to the operator of excessive rod insertion. The insertion limit maintains sufficient core reactivity shutdown margin following reactor trip and provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection, and limits rod insertion such

that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased (the rods must be withdrawn further) with increasing power. Two (2) parameters which are proportional to power are used as inputs to the insertion monitor. These are the ΔT between the hot leg and the cold leg, which is a direct function of reactor power, and T_{avg}, which is programmed as a function of power. The rod insertion monitor uses parameters for each control rod bank as follows:

$$Z_{LL} = A(\Delta T)_{median} + B(T_{avg})_{median} + C$$

where:

Z_{LL}	=	Maximum permissible insertion limit for affected control bank.
$(\Delta T)_{median}$	=	Median ΔT of all loops.
$(T_{avg})_{median}$	=	Median T_{avg} of all loops.
A,B,C	=	Constants chosen to maintain $Z_{LL} \geq$ actual limit based on physics calculations.

The control rod bank demand position (Z) is compared to Z_{LL} as follows:

If $Z - Z_{LL} \leq D$ a low alarm is actuated.

If $Z - Z_{LL} \leq E$ a low-low alarm is actuated.

Actuation of the low alarm alerts the operator of an approach to a reduced shutdown reactivity situation. Administrative procedures require the operator to add boron through the Chemical and Volume Control System. Actuation of the low-low alarm requires the operator to initiate emergency boration procedures. The value for "E" is chosen such that the low-low alarm would normally be actuated before the insertion limit is reached. The value for "D" is chosen to allow the operator to follow normal boration procedures. Figure 7.7-2 shows a block diagram representation of the control rod bank insertion monitor. The monitor is shown in more detail on the functional diagrams shown in Figure 7.2-1, Sheet 9. In addition to the rod insertion monitor for the control banks, the plant computer, which monitors individual rod positions, provides an alarm that is associated with the rod deviation alarm discussed in Section 7.7.1.3.4 is provided to warn the operator if any shutdown rod cluster control assembly leaves the fully withdrawn position.

Rod insertion limits are established by:

1. Establishing the allowed rod reactivity insertion at full power consistent with the purposes given above.

2. Establishing the differential reactivity worth of the control rods when moved in normal sequence.

3. Establishing the change in reactivity with power level by relating power level to rod position.

4. Linearizing the resultant limit curve. All key nuclear parameters in this procedure are measured as part of the initial and periodic physics testing program.

Any unexpected change in the position of the control bank under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate indication of a change in the reactivity status of the reactor. In addition, samples are taken periodically of coolant boron concentration. Variations in concentration during core life provide an additional check on the reactivity status of the reactor, including core depletion.

7.7.1.3.4 Rod Deviation Alarm

A rod deviation function is performed as part of the Digital Rod Position Indication System where an alarm is generated if a preset limit is exceeded as a result of a comparison of any control rod against the other rods in a bank. The deviation alarm of a shutdown rod is based on a preset insertion limit being exceeded.

The demanded and measured rod position signals are also monitored by the plant computer which provides a visual printout and an audible alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm can be set with appropriate allowance for instrument error and within sufficiently narrow limits to preclude exceeding core design hot channel factors.

Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system implemented by the plant computer. Additionally, the Digital Rod Position Indication System contains rod deviation circuitry that detects and alarms the following conditions:

1. When any 2 rods within the same control bank are misaligned by a preset distance ($\geq$ 13 steps) and

2. When any shutdown rod is below the full-out position by a preset distance (18 steps).

7.7.1.3.5 Rod Bottom Alarm

A rod bottom signal for the full length rods in the Digital Rod Position System is used to operate a control relay, which generates the "ROD BOTTOM ROD DROP" alarm.

7.7.1.4 <u>Plant Control System Interlocks</u>

The listing of the Plant Control System interlocks, along with the description of their derivations and functions, is presented in Table 7.7-1. It is noted that the designation numbers for these interlocks are preceded by "C". The development of these logic functions is shown in the functional diagrams (Figure 7.2-1, Sheets 9 to 15).

7.7.1.4.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by either a Control System malfunction or operator violation of administrative procedures.

Rod stops are the C_1, C_2, C_3, C_4, and C_5 control interlocks identified in Table 7.7-1. The C_3 rod stop derived from overtemperature ΔT and the C_4 rod stop, derived from overpower ΔT are also used for turbine runback, which is discussed below.

7.7.1.4.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation that might lead to an undesirable condition, which, if reached, will be protected by reactor trip.

Turbine load reference reduction is initiated by either an overtemperature or overpower ΔT signal. Two (2) out of 3 coincidence logic is used.
A rod stop and turbine runback are initiated when:

$$\Delta T > \Delta T_{rod\ stop}$$

for both the overtemperature and the overpower condition.

For either condition in general:

$$\Delta T_{rod\ stop} = \Delta T_{setpoint} - B_p$$

where:

B_p = a setpoint bias.

Where $\Delta T_{setpoint}$ refers to the overtemperature ΔT reactor trip value and the overpower ΔT reactor trip value for the 2 conditions.

The turbine runback is continued until ΔT is equal to or less than $\Delta T_{rod\ stop}$. This function serves to maintain an essentially constant margin to trip.

7.7.1.5 Pressurizer Pressure Control

The Reactor Coolant System pressure is controlled by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer plus steam relief for large transients. The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater group is proportionally controlled to correct small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (backup) heaters are turned on automatically or manually to control pressure in conjunction with the control heaters and spray.

The spray nozzles are located on the top of the pressurizer. Spray is initiated when the pressure controller spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing spray demand signal until it reaches a maximum value.

Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Power relief valves limit system pressure for large positive pressure transients. In the event of a large load reduction, not exceeding the design plant load rejection capability, the pressurizer power operated relief valves might be actuated for the most adverse conditions, e.g., the most negative Doppler coefficient, and the maximum incremental rod worth.

Diagrams of the pressurizer pressure control system are shown on Figures 7.7-4 and 7.2-1 Sheets 11 and 12.

7.7.1.6 Pressurizer Water Level Control

The pressurizer operates by maintaining a steam cushion over the reactor coolant. As the density of the reactor coolant adjusts to the various temperatures, the steam water interface moves to absorb the variations with relatively small pressure disturbances.

The water inventory in the Reactor Coolant System is maintained by the Chemical and Volume Control System. During normal plant operation, the charging flow varies to produce the flow demanded by the pressurizer water level controller. The pressurizer water level is programmed as a function of coolant average temperature, with the highest average temperature (auctioneered) being used. The pressurizer water level decreases as the load is reduced from full load. This is a result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes.

To control pressurizer water level during startup and shutdown operations, the charging flow is manually regulated from the Main Control Room.

A block diagram of the Pressurizer Water Level Control System is shown on Figure 7.7-5.

7.7.1.7 Steam Generator Water Level Control

Each steam generator is equipped with a 3 element feedwater flow controller which maintains a programmed water level which is a function of reactor flux. The 3 element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the steam generator water level signal, the programmed level and the pressure compensated steam flow signal. In addition, the feedwater pump speed is varied to maintain a programmed pressure differential between the steam header and the feed pump discharge header. The speed controller continuously compares the actual ΔP with a programmed ΔP_{ref} which is a linear function of steam flow. Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor following a reactor trip and turbine trip. An override signal closes the feedwater valves when the average coolant temperature is below a given temperature and the reactor has tripped. Manual override of the feedwater control system is available at all times. | 99-01

When the plant is operating at very low power levels (as during startup), the steam and feedwater flow signals will not be usable for control. Therefore, a secondary automatic control system is provided for operation at low power. This system uses the steam generator water level and nuclear power signals in a feed forward control scheme to position a bypass valve which is in parallel with the main feedwater regulating valve. Switchover from the Bypass Feedwater Control System (low power) to the Main Feedwater Control System is initiated by the operator at approximately 25% power.

A block diagram of the Steam Generator Water Level Control System is shown in Figure 7.7-6 and 7.7-7.

7.7.1.8 Steam Dump Control

The Steam Dump System is designed to accept a 100% loss of net load without tripping the reactor.

The Automatic Steam Dump System is able to accommodate this abnormal load rejection and to reduce the effects of the transient imposed upon the Reactor Coolant System. By bypassing main steam directly to the condenser and/or the atmosphere, an artificial load is thereby maintained on the primary system. The Rod Control System can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The steam dump system flow capacity is 85% of full load steam flow at full load steam pressure.

If the difference between the reference T_{avg} (T_{ref}) based on turbine first stage pressure and the lead/lag compensated median T_{avg} exceeds a predetermined amount, and the interlock mentioned below is satisfied, a demand signal will actuate the steam dump to maintain the Reactor Coolant System temperature within control range until a new equilibrium condition is reached.

A lead/lag compensation to this T_{ref} signal is provided to improve steam dump response and provide a stable steam dump control. This allows for reducing T_{hot}, thereby opening the steam dumps at a lower temperature error.

To prevent actuation of steam dump on small load perturbations, an independent load rejection sensing circuit is provided. This circuit senses the rate of decrease in the turbine load as detected by the turbine first stage pressure. It is provided to unblock the dump valves when the rate of load rejection exceeds a preset value corresponding to a 10% step load decrease or a sustained ramp load decrease of 5%/minute. Additional interlocks for steam dump are described in Table 7.3-3, designation P-12, and Table 7.7-1, designations C-7, C-8, C-9, C-15, and C-16.

Block diagrams of the Steam Dump Control System are shown on Figure 7.2-1, Sheet 10, and Figure 7.7-8

7.7.1.8.1 Load Rejection Steam Dump Controller

This circuit prevents large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead/lag compensated median T_{avg} and the reference T_{avg} is based on turbine first stage pressure.

The T_{avg} signal is the same as that used in the Reactor Coolant System. The lead/lag compensation for the T_{avg} signal is to compensate for lags in the plant thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available, in this situation steam dump terminates as the error comes within the maneuvering capability of the control rods.

7.7.1.8.2 Turbine Trip Steam Dump Controller

Following a turbine trip, as monitored by the turbine trip signal, the load rejection steam dump controller is defeated and the turbine trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead/lag compensated median T_{avg} and the no load reference T_{avg}. When the error signal exceeds a predetermined setpoint the dump valves are tripped open in a prescribed sequence. As the error signal reduces in magnitude indicating that the Reactor Coolant System T_{avg} is being reduced toward the reference no load value, the dump valves are modulated by the plant trip controller to regulate the rate of decay heat removal and thus gradually establish the equilibrium hot shutdown condition.

Following a turbine trip only sufficient steam dump capacity is necessary to maintain steam pressure below the steam generator relief valve setpoint (approximately 40% capacity to the condenser); therefore, only the first 2 groups of valves are opened. The error signal determines whether a group is to be tripped open or modulated open. The valves are modulated when the error is below the trip-open setpoints.

7.7.1.8.3 Steam Header Pressure Controller

Residual heat removal is maintained by the steam generator pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following a turbine and reactor trip.

7.7.1.9 Incore Instrumentation

The Incore Instrumentation System consists of Chromel-Alumel thermocouples at fixed core outlet positions and movable miniature neutron detectors which can be positioned at the center of selected fuel assemblies, anywhere along the length of the fuel assembly vertical axis. The basic system for insertion of these detectors is shown in Figure 7.7-9.

7.7.1.9.1 Thermocouples

This section deleted by Amendment 1, August 1985.

7.7.1.9.2 Movable Neutron Flux Detector Drive System

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux mapping of the core. The stainless steel detector shell is welded to the leading end of helical wrap drive cable and to stainless steel sheathed coaxial cable. The retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal table. Their distribution over the core is nearly uniform with about the same number of thimbles located in each quadrant.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the Reactor Coolant System and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal line. During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal line is provided for the retraction operation.

The Drive System for the insertion of the miniature detectors consists basically of drive assemblies, 5 path rotary transfer assemblies, and 10 path rotary transfer assemblies, as shown in Figure 7.7-9. The Drive System pushes hollow helical wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor which pushes a helical wrap drive cable and detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length.

Manual isolation valves (1 for each thimble) are provided for closing the thimbles. When closed, the valves form a 2500 psig barrier. The manual isolation valves are not designed to isolate a thimble while a detector/drive cable is inserted into the thimble. The detector/drive cable must be retracted to a position above the isolation valve prior to closing the valve.

A small leak would probably not prevent access to the isolation valves and thus a leaking thimble could be isolated during a hot shutdown. A large leak might require cold shutdown for access to the isolation valve.

7.7.1.9.3 Control and Readout Description

The Control and Readout System provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors while plotting neutron flux versus detector position. The Control System is located in the Control Room. Limit switches in each transfer device provide feedback of path selection operation. Each gear box drives an encoder for position feedback. One (1) 5 path operation selector is provided for each drive unit to insert the detector in one of 5 functional modes of operation. One (1) 10 path operation selector is also provided for each drive unit that is used to route a detector into any 1 of up to 10 selectable paths. A common path is provided to permit cross calibration of the detectors.

The Control Room contains the necessary equipment for control, position indication, and flux recording for each detector.

A "flux-mapping" consists, briefly, of selecting (by panel switches) flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot (position versus flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner other core locations are selected and plotted. Each detector provides axial flux distribution data along the center of a fuel assembly.

Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

The number and location of these thimbles have been chosen to permit measurement of local to average peaking factors to an accuracy of ± 5% (95% confidence). Measured nuclear peaking factors will be increased by 5% to allow for this accuracy. If the measured power peaking is larger than acceptable, reduced power capability will be indicated.

Operating plant experience has demonstrated the adequacy of the incore instrumentation in meeting the design bases stated.

7.7.1.10 <u>Boron Concentration Measurement System</u>

The Boron Concentration Measurement System employs a sample measurement unit which contains a neutron source and neutron detector located in a shield tank. Piping within the shield tank is arranged to maintain coolant sample flow between the neutron source and the neutron detector. Neutron absorption by the boron in the coolant sample flow reduces the number of neutrons which contact the detector per unit time. Therefore, the time required to count a fixed number of neutron contacts is variable and dependent upon the concentration of boron solution. Electronic circuitry in the console portion of the Boron Concentration Measurement System accepts an amplified signal from the sample measurement unit and converts the signal to a digital display of ppm boron. The digital display is mounted on the control board.

00-01

The Boron Concentration Measurement System is designed for use as an advisory system. It is not designed as a safeguards system or component of a safeguards system. The Boron Concentration Measurement System is not part of a control element or control system, nor is it designed for this use. No credit is taken for this system in any accident analysis. Therefore, redundancies of measurement components, self-checking subsystems, malfunction annunciations, and diagnostic circuitry are not included in this system. As a general operating aid it provides information as to when additional check analyses are warranted rather than a basis for fundamental operating decisions. 00-01

7.7.2 ANALYSIS

The plant control systems are designed to assure high reliability in any anticipated operational occurrences. Equipment used in these systems is designed and constructed with a high level of reliability.

Proper positioning of the control rods is monitored in the Control Room by bank arrangements of the individual position columns for each rod cluster control assembly. A rod deviation alarm alerts the operator of a deviation of 1 rod cluster control assembly from the other rack in that bank position. There are also insertion limit monitors with visual and audible annunciation. A rod bottom alarm signal is provided to the Control Room for each full length rod cluster control assembly. Four (4) excore long ion chambers also detect asymmetrical flux distribution indicative of rod misalignment.

Overall reactivity control is achieved by the combination of soluble boron and rod cluster control assemblies. Long term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short term reactivity control for power changes is accomplished by the Plant Control System which automatically moves rod cluster control assemblies. This system uses input signals including neutron flux, coolant temperature, and turbine load.

The Plant Control Systems will prevent an undesirable condition in the operation of the plant that, if reached, will be protected by reactor trip. The description and analysis of this protection is covered in Section 7.2. Worst case failure modes of the Plant Control Systems are postulated in the analysis of off-design operational transients and accidents covered in Chapter 15, such as, the following:

1. Uncontrolled rod cluster control assembly withdrawal from a subcritical condition.

2. Uncontrolled rod cluster control assembly withdrawal at power.

3. Rod cluster control assembly misalignment.

4. Loss of external electrical load and/or turbine trip.

5. Loss of all a-c power to the station auxiliaries.

6. Excessive heat removal due to Feedwater System malfunctions.

7. Excessive load increase incident.

8. Accidental depressurization of the Reactor Coolant System.

These analyses show that a reactor trip setpoint is reached in time to protect the health and safety of the public under those postulated incidents and that the resulting coolant temperatures produce a departure from nucleate boiling (DNBR) well above the limiting value of 1.30. Thus, there will be no cladding damage and no release of fission products to the Reactor Coolant System under the assumption of these postulated worst case failure modes of the plant control system.

7.7.2.1 Separation of Protection and Control System

In some cases, it is advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel. As such, a failure in the control circuitry does not adversely affect the protection channel. Test results have shown that a short circuit or the application (credible fault voltage from within the cabinets) of 120 volt a-c ± 1% or 140 volt d-c on the isolated output portion of the circuit (nonprotection side of the circuit) will not affect the input (protection) side of the circuit. 99-01

Where a single random failure can cause a control system action that results in a generating station condition requiring protective action and can also prevent proper action of a protection system channel designed to protect against the condition, the remaining redundant protection channels are capable of providing the protective action even when degraded by a second random failure. The loop T_{avg} and Delta-T channel required inputs to the Steam Dump System, Reactor Control System, the Control Rod Insertion Monitor and the Pressurizer Level Control System are electrically isolated prior to being routed to the control cabinets. A median signal is then calculated for T_{avg} and Delta-T in the control cabinets utilizing a Median Signal Selection (MSS) for input to the appropriate control systems. This meets the applicable requirements of Section 4.7 of IEEE Standard 279-1971.

The pressurizer pressure channels needed to derive the control signals are electrically isolated from protection.

7.7.2.2 Response Considerations of Reactivity

Reactor shutdown with control rods is completely independent of the control functions since the trip breakers interrupt power to the full length rod drive mechanisms regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits. The design meets the requirements of the 1971 General Design Criteria 25.

No single electrical or mechanical failure in the Rod Control System could cause the accidental withdrawal of a single rod cluster control assembly from the partially inserted bank at full power operation. The operator could deliberately withdraw a single rod cluster control assembly in the control bank; this feature is necessary in order to retrieve a rod, should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures which could result in a single rod cluster control assembly withdrawal, rod deviation would be displayed on the plant annunciator, and the individual rod position readouts would indicate the relative positions of the rods in the bank. Withdrawal of a single rod cluster control assembly by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of control and shutdown rods in the system is divided into 2 groups (group 1 and group 2) of 4 mechanisms each. The rods comprising a group operate in parallel through multiplexing thyristors. The 2 groups in a bank move sequentially such that the first group is always within 1 step of the second group in the bank. The group 1 and group 2 power circuits are installed in different cabinets as shown in Figure 7.7-15, which also shows that 1 group is always within 1 step (5/8 inch) of the other group. A definite schedule of actuation or deactuation of the stationary gripper, moveable gripper, and lift coils of a mechanism is required to withdraw the rod cluster control assembly attached to the mechanism. Since the 4 stationary gripper, moveable gripper, and lift coils associated with the rod cluster control assemblies of a rod group are driven in parallel, any single failure which could cause rod withdrawal would affect a minimum of 1 group of rod cluster control assemblies. Mechanical failures are in the direction of insertion, or immobility.

Figure 7.7-15 is provided for a discussion of design features that assure that no single electrical failure could cause the accidental withdrawal of a single rod cluster control assembly from the partially inserted bank at full power operation.

The Figure 7.7-15 shows the typical parallel connections on the lift, movable and stationary coils for a group of rods. Since single failures in the stationary or movable circuits will result in dropping or preventing rod (or rods) motion, the discussion of single failure will be addressed to the lift coil circuits. 1) Due to the method of wiring the pulse transformers which fire the lift coil multiplex thyristors, 3 of the 4 thyristors in a rod group could remain turned off when required to fire, if for example the gate signal lead failed open at point χ_1. Upon "up" demand, 1 rod in group 1 and 4 rods in group 2 would

withdraw. A second failure at point χ_2 in group 2 circuit is required to withdraw 1 rod cluster control assembly; 2) Timing circuit failures will affect the 4 mechanisms of a group or the 8 mechanisms of the bank and will not cause a single rod withdrawal; 3) More than 2 simultaneous component failures are required (other than the open wire failures) to allow withdrawal of a single rod.

The identified multiple failure involving the least number of components consists of open circuit failure of the proper 2 out of 16 wires connected to the gate of the lift coil thyristors. The probability of open wire (or terminal) failure is 0.016×10^{-6} per hour by MIL-HDB217A. These wire failures would have to be accompanied by failure, or disregard, of the indications mentioned above. The probability of this occurrence is therefore too low to have any significance.

Concerning the human element, to erroneously withdraw a single rod cluster control assembly, the operator would have to improperly set the blank selector switch, the lift coil disconnect switches, and the in hold out switch. In addition, the indications would have to be disregarded or ineffective. Such series of errors would require a complete lack of understanding and administrative control. A probability number cannot be assigned to a series of errors such as these.

The Rod Position Indication System provides direct visual displays of each control rod assembly position. The plant computer alarms for deviation of rods from their banks. In addition a rod insertion limit monitor provides an audible and visual alarm to warn the operator of an approach to an abnormal condition due to dilution. The low-low insertion limit alarm alerts the operator to follow emergency boration procedures. The facility reactivity control systems are such that acceptable fuel damage limits will not be exceeded even in the event of a single malfunction of either system.

An important feature of the Control Rod System is that insertion is provided by gravity fall of the rods.

In all analyses involving reactor trip, the single, highest worth rod cluster control assembly is postulated to remain untripped in its full out position.

One means of detecting a stuck control rod assembly is available from the actual rod position information displayed on the control board. There is a control board rod position readout with one for each full length rod, to provide the plant operator actual position of the rod in steps. The indications are grouped by banks (e.g., control bank A, control bank B, etc.) to indicate to the operator the deviation of one rod with respect to other rods in a bank. This serves as a means to identify rod deviation. 98-01

The plant computer monitors the actual position of all rods. Should a rod be misaligned from the other rods in that bank by more than 15 inches, the rod deviation alarm is actuated.

Misaligned rod cluster control assemblies are also detected and alarmed in the Control Room via the Flux Tilt Monitoring System which is independent of the plant computer. Isolated signals derived from the Nuclear Instrumentation System are compared with one another to determine if a preset amount of deviation of average power level has occurred. Should such a deviation occur the comparator output will operate a bistable unit to actuate a control board annunciator. This alarm will alert the operator to a power imbalance caused by a misaligned rod. By use of individual rod position readouts, the operator can determine the deviating control rod and take corrective action. The design of the Plant Control Systems meets the requirements of the 1971 General Design Criteria 23. 00-01

Refer to Section 4.3.2.1 for additional information on response considerations due to reactivity.

7.7.2.3 Step Load Changes Without Steam Dump

The Plant Control System restores equilibrium conditions, without a trip, following a plus or minus 10% step change in load demand, over the 15 to 100% power range for automatic control. Steam dump is blocked for load decrease less than or equal to 10%. A load demand greater than full power is prohibited by the turbine control load limit devices.

The Plant Control System minimizes the reactor coolant average temperature deviation during the transient within a given value and restores average temperature to the programmed setpoint. Excessive pressurizer pressure variations are prevented by using spray and heaters and power relief valves in the pressurizer.

The control system must limit nuclear power overshoot to acceptable values following a 10% increase in load to 100%.

7.7.2.4 Loading and Unloading

Ramp loading and unloading of 5% per minute can be accepted over the 15 to 100% power range under automatic control without tripping the plant. The function of the control system is to maintain the coolant average temperature as a function of turbine generator load.

The coolant average temperature increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The pressurizer heaters limit the resulting system pressure decrease. The pressurizer water level is programmed such that the water level is above the setpoint for heater cut out during the loading and unloading transients. The primary concern during loading is to limit the overshoot in nuclear power and to provide sufficient margin in the overtemperature ΔT setpoint.

The automatic load controls are designed to adjust the unit generation to match load requirements within the limits of the unit capability and licensed rating.

7.7.2.5 Load Rejection Furnished by Steam Dump System

When a load rejection occurs, if the difference between the required temperature setpoint of the Reactor Coolant System and the actual average temperature exceeds a predetermined amount, a signal will actuate the steam dump to maintain the Reactor Coolant System temperature within control range until a new equilibrium condition is reached.

The reactor power is reduced at a rate consistent with the capability of the Rod Control System. Reduction of the reactor power is automatic. The steam dump flow reduction is as fast as rod cluster control assemblies are capable of inserting negative reactivity.

The Rod Control System can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The steam dump steam flow capacity is ~ 93.6% of full load steam flow at full load steam pressure.

The steam dump flow reduces proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from loss of load.

7.7.2.6 Turbine Generator Trip with Reactor Trip

Whenever the turbine generator unit trips at an operating power level above 50% power, the reactor also trips. The unit is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the equivalent saturation pressure of the steam generator safety valve setpoint. The thermal capacity of the Reactor Coolant System is greater than that of the Secondary System, and because the full load average temperature is greater than the no load temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power. This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of feedwater to the steam generators. 99-01

The Steam Dump System is controlled from the reactor coolant average temperature signal whose setpoint values are programmed as a function of turbine load. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves. With the dump valves open, the average coolant temperature starts to reduce quickly to the no load setpoint. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam which is by-passed.

Following the turbine trip, the feedwater flow is cut off when the average coolant temperature decreases below a given temperature or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator water level while assuring that the reactor coolant temperature is at the desired value. Residual heat removal is controlled by the steam (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. The pressurizer water level is programmed so that the level following the turbine and reactor trip is above the heaters. However, if the heaters become uncovered following the trip, the Chemical and Volume Control System will provide a full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

The Steam Dump and Feedwater Control Systems are designed to prevent the average coolant temperature from falling below the programmed no load temperature following the trip to ensure adequate reactivity shutdown margin.

7.7.3 TECHNICAL SUPPORT COMPLEX (TSC)

7.7.3.1 Description

In response to the recommendations issued post-TMI (e.g., NUREG-0578, NUREG-0585), South Carolina Gas and Electric will incorporate into the Virgil C. Summer Nuclear Power Plant a Technical Support Complex (TSC). This complex will improve the information available to operating and technical personnel. The 3 elements of the Technical Support Complex are:

1. ON-SITE Technical Support Center (OSTS).

2. Bypass and Inoperable Status Indication (BISI)

3. Safety Parameter Display System SPDS)

The ON-SITE Technical Support Center is at a location adjacent to but separate from the Control Room. Key plant information can be displayed in and transmitted from the ON-SITE Technical Support Center to those technical personnel who are responsible for engineering support during post accident recovery. The center has the capability to receive, process, and display analog and digital signals from both the Nuclear Steam Supply System and balance of plant parts of the plant.

Bypass and Inoperable Status Indication provides the operator with a clear indication of the availability of plant safety systems. It provides the operator and OTSC personnel with a continuous systems level indication of bypasses or inoperable status of the systems comprising the Engineered Safety Features.

The purpose of the safety parameter display system (SPDS) is to assist operating personnel in evaluating the safety status of the plant. The safety parameter display system provides a continuous indication of plant parameters or derived variables which are representative of the safety status of the plant during both normal and emergency use. The primary function of the SPDS is to aid in the rapid detection of abnormal operating conditions. Secondary functions include analyzing and diagnosing the abnormality, and providing an informational basis for corrective action execution.

The Technical Support Complex is located in the Control Building, elevation 463'0", separate from but next to, the Control Room and is capable of accommodating a minimum of 25 persons (see Figure 1.2-15). Access to the Control Room is available through connecting doors between the Technical Support Complex and the Control Room. Print storage and plant information will be available in the Technical Support Center. The Technical Support Complex contains the following areas:

1. Data Display Room - This contains the communications and monitoring equipment necessary to provide the engineering and management support functions during an accident condition. The Communications, monitoring, and display equipment in this area includes:

    a. Communications Network including plant telephones, dedicated lines to external parties, and radio systems.

2. SCE&G Co. Technical Area - Office and communications facilities for SCE&G assigned personnel.

3. NRC Office - Office and communications for 5 NRC assigned personnel.

4. Operations Conference Room - Conference Room facilities.

5. Westinghouse Office - Office and communications facilities for plant personnel to communicate with Westinghouse.

6. GAI Office - Office and communications facilities for plant personnel to communicate with GAI.

7. Emergency Monitoring Team Office - Office facilities for the SCE&G Co. emergency monitoring team.

The Technical Support Complex is habitable to the same environmental conditions as the Control Room for postulated accident conditions. (The Technical Support Complex has the same air supply and exhaust system as the Control Room, see Section 9.4.1.2.1). | 99-01

Installed radiation monitors (RM-G1 and RM-A1) will detect direct radiation and airborne radioactive contaminants for both the Control Room and the Technical Support Complex. The monitors will alarm when high radiation levels are being approached. SCE&G Co. has established in the plant's emergency procedures the necessary precautionary protective measures to be taken for high levels of radiation.

7.7.3.2 Analysis

1. The Technical Support Complex is located on elevation 463'0" of the Control Building, which is a Seismic Category I structure.

2. The environmental conditions within the Technical Support Complex are the same as those in the Control Room.

3. Installed radiation monitors (RM-G1 and RM-A1) will detect direct radiation and airborne radioactive contaminants for both the Control Room and the TSC. The monitors will alarm when high radiation levels are being approached.

4. Equipment within the Technical Support Complex is designed to assure reliability in the recovery of data.

5. The Technical Support Complex and equipment located in the Technical Support Complex are not required to initiate actuation of safety related systems. Loss of the Technical Support Complex or any equipment within the TSC will not prevent safe shutdown of the plant.

7.7.4 CRITICAL SYSTEMS LEAK MONITORING SYSTEM

7.7.4.1 Description

An acoustical type leak monitoring system is provided to detect through the wall and valve seat leakage downstream of the pressurizer safety valves.

The sensors and preamps for the system are located inside the Reactor Building, with all other conditioning components located outside.

A leak through a valve seat generates metal borne acoustic waves which are detected by acoustic transducers mounted on the piping adjacent to the valves. The transducers convert the acoustic waves into electrical signals which are amplified and then transmitted to the Leak Detection System.

The Control Room is provided with indication which relates to the size of the leak and an alarm which alerts the operator of the occurrence of a leak. The system is provided with multiple sensors to enable the plant operator to determine which pressurizer safety valve is open.

7.7.4.2 Analysis

The Critical Systems Leak Monitoring System is powered from a vital instrument bus. The system will be qualified to IEEE 323-1971 and IEEE 344-1975. Seismic and environmental qualification is discussed in Section 3.10 and 3.11, respectively. 00-01

7.7.5 REACTOR VESSEL LEVEL INSTRUMENTATION SYSTEM

This section deleted by Amendment 4.

7.7.6 CORE SUBCOOLING MONITOR

This section deleted by Amendment 1, August 1985.

7.7.7 REFERENCES

1. Lipchak, J. B. and Stokes, R. A., "Nuclear Instrumentation System," WCAP-8255, January, 1974.

2. "Calculation of Distance Factors for Power and Test Reactor Sites," J. J. Dinunno, et al, U. S. Atomic Energy Commission, Washington, D. C., March, 1962.

TABLE 7.7-1

PLANT CONTROL SYSTEM INTERLOCKS

DESIGNATION	DERIVATION	FUNCTION
C-1	1/2 Neutron flux (intermediate range) above setpoint	Blocks automatic and manual control rod withdrawal
C-2	1/4 Neutron flux (power range) above setpoint	Blocks automatic and manual control rod withdrawal
C-3	2/3 Overtemperature ΔT above setpoint	Blocks automatic and manual control rod withdrawal Actuates turbine runback via load reference Defeats remote load dispatching (if remote load dispatching is used)
C-4	2/3 Overpower ΔT above setpoint	Blocks automatic and manual control rod withdrawal Actuates turbine runback via load reference Defeats remote load dispatching (if remote load dispatching is used)
C-5	1/1 Turbine first stage pressure below setpoint	Defeats remote load dispatching (if remote load dispatching is used) Blocks automatic control rod withdrawal
C-7	1/1 Time derivative (absolute value) of turbine first stage pressure (decrease only) above setpoint	Makes steam dump valves available for either tripping or modulation

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Amendment 00-01

TABLE 7.7-1 (Continued)

PLANT CONTROL SYSTEM INTERLOCKS

DESIGNATION	DERIVATION	FUNCTION
C-8	Turbine trip, 2/3 turbine emergency trip fluid pressure below setpoint or 4/4 turbine valves closed	Blocks steam dump control via load rejection T_{avg} Controller Makes steam dump valves available for either tripping or modulation
	No turbine trip, 2/3 turbine emergency trip fluid pressure above setpoint and 1/4 turbine inlet line stop valves not closed.	Blocks steam dump control via turbine trip T_{avg} controller
C-9	Any condenser pressure above setpoint, or circulation water pump breakers open	Blocks steam dump to condenser
C-11	1/1 Bank D control rod position above setpoint	Blocks automatic rod withdrawal
C-15	1/1 Generator loss of stator coolant, runback has occurred	Block steam dump to one pair of the four pairs of condenser steam dump valves (not the cooldown valves)
C-16	1/1 Condenser pressure above 4.5 inches of mercury	Block steam dump to one pair of condenser steam dump valves (not cooldown valves or valves blocked by designation C-15, above)

TABLE 7.7-2

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Figure 7.7-10, (Deleted per RN 99-085)
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	8.3-2e	0	August 1984		8C-4	00-01	December 2000
	8.3-2f	0	August 1984		8C-5	00-01	December 2000
	8.3-2g	0	August 1984		8C-6	00-01	December 2000
	8.3-3	0	August 1984		8C-7	00-01	December 2000
	8.3-4	00-01	December 2000		8C-8	97-01	August 1997
	8.3-4b	00-01	December 2000		8C-9	97-01	August 1997
	8.3-5	00-01	December 2000		8C-10	97-01	August 1997
	8.3-6	0	August 1984		8C-11	97-01	August 1997
	8.3-7	98-01	April 1998		8C-12	97-01	August 1997
	8.3-8	0	August 1984		8C-13	97-01	August 1997
	8.4-1	00-01	December 2000		8C-14	97-01	August 1997
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	8A-4	00-01	December 2000		8C-20	97-01	August 1997
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	8B-3	00-01	December 2000		8C-23	97-01	August 1997
	8B-4	00-01	December 2000		8C-24	97-01	August 1997
Fig.	8B-1	0	August 1984		8C-25	97-01	August 1997
	8B-2	0	August 1984		8C-26	97-01	August 1997
	8B-3	0	August 1984		8C-27	97-01	August 1997
	8B-4	0	August 1984		8C-28	97-01	August 1997
	8B-5	0	August 1984		8C-29	97-01	August 1997
	8B-6	0	August 1984		8C-30	97-01	August 1997
	8B-7	0	August 1984		8C-31	97-01	August 1997
	8B-8	0	August 1984		8C-32	97-01	August 1997
	8B-9	0	August 1984		8C-33	97-01	August 1997
	8B-10	0	August 1984		8C-34	97-01	August 1997
	8B-11	0	August 1984		8C-35	97-01	August 1997
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8.0 ELECTRIC POWER

8.1 INTRODUCTION

The Licensee's transmission system, along with points of interconnection with neighboring utilities, is shown in Figure 8.1-1. The Licensee is a member utility of the Virginia-Carolinas (VACAR) Subregion Reliability Agreement which is a part of the Southeastern Reliability Council. As a member of such a group, the Licensee can supply power to, or consume power from other members, as its system allows or demands. Transmission system ties to other utilities are as listed in Table 8.1-1. The specific interface between the transmission grid and the Virgil C. Summer Nuclear Station is discussed in Section 8.2.

The Virgil C. Summer Nuclear Station 230 kV substation has a single bus, single breaker arrangement, with three main bus sections. The center section is designated bus section 3, the east section designated bus section 1 and the west section designated bus section 2. A tap from bus section 3 provides a subsection of this bus with two bay positions for the Fairfield No. 1 and No. 2 lines.

The Parr 115 kV engineered safety features (ESF) line terminates in a bay in bus section 3, crosses over bus section 3 with rigid bus construction, and continues to the Virgil C. Summer Nuclear Station.

The onsite power network consists of three non-Class 1E distribution networks and two independent, redundant Class 1E distribution networks. The voltage levels of each network are 7200 volts, 480 volts and 120 volt a-c and 125 volt d-c.

The main source of power for the non-Class 1E networks is the unit auxiliary transformer which is connected to the output of the main generator between the generator circuit breaker and the low voltage bushings of the main power transformer (see Figure 8.2-3).

The emergency auxiliary transformers provide an emergency source of power for the non-Class 1E distribution network.

The normal source of power for the two independent Class 1E distribution networks are the ESF transformers and a winding of the emergency auxiliary transformers. These two sources of power also serve as an alternate source of power to each other (see Figures 8.2-3 and 8.2-4).

Two diesel generators are provided, one for each of the Class 1E buses to serve as an emergency source of power. The safety-related loads their safety functions and power requirements, supplied by the two emergency diesel generators are listed in Table 8.3-3. The ESF battery buses, inverter buses and associated loads are shown by Figures 8.3-1 and 8.3-2.

The Class 1E power network provides an adequate and reliable source of electric power for safe reactor shutdown following any design basis event, including loss of offsite power and for all normal modes of station operation.

The Virgil C. Summer Nuclear Station electrical systems are designed to comply with the scope of IEEE-308 [1] as specified in Section 1 of IEEE-308. Onsite power systems are designed to satisfy the applicable criteria of Reference [1], as well as the criteria of Regulatory Guides 1.6 and 1.9 (see Appendix 3A).

Implementation of IEEE Standards and the extent to which any alternative approaches are used is itemized in Table 8.1-2. Applicable criteria, including: General Design Criteria, Appendix A to 10 CFR 50; Regulatory Guides; and Branch Technical Positions are listed in Table 8.1-3 with references to appropriate sections of this FSAR. Implementation of Regulatory Guides is discussed in Appendix 3A.

8.1.1 REFERENCES

1. Institute of Electrical and Electronics Engineers, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations," IEEE-308-1971.

TABLE 8.1-1

TRANSMISSION SYSTEM TIES TO OTHER UTILITIES

South Carolina Electric and Gas Company	South Carolina Public Service Authority	Voltages(kV)
Virgil C. Summer	Blythewood	230
Virgil C. Summer	Newberry	230
Arthur M. Williams	Charity	230
Lyles	Eastover	115
Lyles	Richland	115
St. George	St. George	115
Faber Place	College Park	115
Faber Place	North Charleston	115
Pepper Hill	Mateeba	230
	Southeastern Power Administration	
CLM Tap	Clark Hill	115
	Duke Power Company	
Parr	Newport	230
Parr	Bush River	230
Georgia Pacific	Bush River (R)	115
White Rock	Bush River (Y)	115
	Carolina Power and Light Company	
Wateree	Sumter	230
Santee	Summerton	230
Eastover	Shaw	115
	Georgia Power Company	
Urquhart	Colnip	115 (N.O.)
Urquhart	Colnit	115 (N.O.)
Calhoun Falls	Hart	115 (N.O.)
Hardeeville	McIntosh	115
	Atomic Energy Commission	
Savannah River Plant	Vogtle	230

TABLE 8.1-2

IMPLEMENTATION OF IEEE STANDARDS

1. IEEE-279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," (ANSI N42.7, 1972).

   Refer to Sections 7.1, 7.2, 7.3 and 7.6.

2. IEEE-308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations."

   Onsite and offsite electrical power systems are designed to satisfy the applicable criteria of IEEE-308-1971.

   Refer to Sections 7.1.2.1.3, 7.6.1.2, 8.1, and 8.2.2.1. 00-01

3. IEEE-317-1972, "Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations."

   Electrical penetrations are designed and fabricated in accordance with the requirements of IEEE-317-1972.

   Refer to Sections 3.11.2.2.2 and 7.1.2.9 and the discussion of Regulatory Guide 1.63 in Appendix 3A.

   IEEE-323-1971, "General Guide for Qualifying Class 1E Electrical Equipment for Nuclear Power Generating Stations."

   00-01

   Environmental Qualification (EQ) of Class 1E electrical equipment is addressed in Section 3.11, which identifies the commitment to NUREG-0588, Cat. II (IEEE-323-1971) for the original plant design. NUREG-0588, Cat. I (IEEE-323-1974), 10CFR50.49, and NRC RG 1.89 requirements have also been used as the bases for environmental qualification, as described in FSAR Section 3.11 and Appendix 3A, under NRC RG 1.89.

4. IEEE-336-1971, "Installation, Inspection and Testing of Nuclear Power Generating Station Protection Systems," (ANSI N45.2.4., 1972).

   Refer to Section 8.3.1.3 and Chapters 14.0 and 17.0.

5. IEEE-338-1971, "IEEE Standard Criteria for the Periodic Testing of Nuclear Power Generating Station Class 1E Power and Protection Systems."

   Refer to Section 7.1.2.11 and Chapter 14.0.

TABLE 8.1-2 (Cont.)

6. IEEE-344-1975, "IEEE Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations." 00-01

   Class 1E electric equipment is tested and data is recorded to ensure that equipment satisfies design performance requirements during and following a safe shutdown earthquake (SSE). The qualification program meets the requirements of IEEE-344-1975 as discussed in Section 3.10. 00-01

7. IEEE-379-1972, "Guide for the Application of the Single Failure Criteria to Nuclear Power Generating Station Protection Systems," (ANSI N41.2).

   Refer to Section 7.1.2.7 and the discussion of Regulatory Guide 1.53 in Appendix 3A.

8. IEEE-384-1974, "Criteria for Separation of Class 1E Equipment and Circuits," (ANSI N41.14).

   Refer to Sections 7.1.2.2.1, 8.3.1.4 and 8.3.1.5 and the discussion of Regulatory Guide 1.75 in Appendix 3A.

9. IEEE-387-1972, "Criteria for Diesel Generator Units Applied As Standby Power Supplies for Nuclear Power Stations."

   IEEE-387-1972 is used as the basis for design criteria for the diesel generators and accessories. Included among the referenced standards in IEEE-387-1972, Section 4.1, are IEEE-308-1971 and IEEE-323-1971. Diesel generators are designed to satisfy these standards.

10. IEEE-450-1987, "Recommended Practice for Maintenance, Testing and Replacement of Large Stationary Type Power Plant and Substation Lead Storage Batteries." 99-01

    Refer to Section 8.3.2.2.2.

TABLE 8.1-3

LIST OF APPLICABLE CRITERIA

	Criteria	Title	Reference FSAR Section(s)
1.	General Design Criteria (GDC), Appendix A to 10 CFR 50		
	GDC-1	Quality Standards and Records	3.1.2
	GDC-2	Design Bases for Protection Against Natural Phenomena	3.1.2, 3.10, 3.11
	GDC-3	Fire Protection	3.1.2, 7.1.2.2.3, 8.3.3.2
	GDC-4	Environmental and Missile Design Bases	3.1.2
	GDC-5	Sharing of Structures, Systems and Components	3.1.2
	GDC-13	Instrumentation and Control	3.1.2, 7.3.1, 7.3.2
	GDC-17	Electric Power Systems	3.1.2, 8.2.1, 8.2.2.2, 8.3.1.2.1, 8.3.2.2.1
	GDC-18	Inspection and Testing of Electric Power Systems	3.1.2, 8.2.1, 8.3.1.2.1, 8.3.2.2.1
	GDC-21	Protection System Reliability and Testability	3.1.2, 7.2.2.2, 7.3.1, 7.3.2
	GDC-22	Protection System Independence	3.1.2, 7.2
	GDC-33	Reactor Coolant Makeup	3.1.2, 8.3
	GDC-34	Residual Heat Removal	3.1.2, 8.3

00-01

TABLE 8.1-3 (Continued)

LIST OF APPLICABLE CRITERIA

	Criteria	Title	Reference FSAR Section(s)
	GDC-35	Emergency Core Cooling	3.1.2, 8.3
	GDC-41	Containment Atmosphere Cleanup	3.1.2, 8.3
	GDC-44	Cooling Water	3.1.2, 8.3
2.	Regulatory Guides (RG)		
	RG 1.6	Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems	App. 3A, 8.1, 8.3.1.2.1, 8.3.2.2.1
	RG 1.9	Selection of Diesel Generator Set Capacity for Standby Power Supplies	App. 3A, 8.1, 8.3.1.1.2.4, 8.3.1.2.1
	RG 1.22	Periodic Testing of Protective System Actuation Functions	App. 3A, 7.1.2.5, 7.3.2
	RG-1.29	Seismic Design Classification	App. 3A 00-01
	RG 1.30	Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment	App. 3A, Chapter 17.0
	RG 1.32	Use of IEEE Std. 308-1971, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations"	App. 3A, 8.2.1, 8.3.1.2.1, 8.3.2.2.1

TABLE 8.1-3 (Continued)

LIST OF APPLICABLE CRITERIA

Criteria	Title	Reference FSAR Section(s)
RG 1.41	Preoperational testing of redundant onsite Electric Power Systems to verify proper load group assignments.	App. 3A, 8.3.1.1.2.6, Chapter 14.0
RG 1.47	Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems	App. 3A, 7.1.2.6
RG 1.53	Application of the Single Failure Criterion to Nuclear Power Plant Protection Systems	App. 3A, 7.1.2.7
RG 1.63	Electric Penetration Assemblies in Containment Structures for Water-Cooled Nuclear Power Plants	App. 3A, 7.1.2.8, 8.3.1.1.4
RG 1.68	Preoperational and Initial Startup Test Programs for Water-Cooled Power Reactors	App. 3A, Chapter 14.0
RG 1.70	Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants	App. 3A
RG 1.75	Physical Independence of Electric Systems	App. 3A, 7.1.2.2.1, 8.3.1.4.3
RG 1.81	Shared Emergency and Shutdown Electric Systems for multi-unit Nuclear Power Plants	App. 3A
RG 1.89	Qualification of Class IE Equipment for Nuclear Power Plants	App. 3A, 3.11, 8.3.1.2.2.1
RG 1.93	Availability of Electric Power Sources	App. 3A

TABLE 8.1-3 (Continued)

LIST OF APPLICABLE CRITERIA

	Criteria	Title	Reference FSAR Section(s)
3.	Branch Technical Positions (ETCSB)		
	ETCSB1	Backfitting of the Protection and Emergency Power Systems of Nuclear Reactors	Chapters 7.0 and 8.0
	ETCSB2	Diesel-Generator Reliability Qualification Testing	8.3.1.1.6
	ETCSB6	Capacity Test Requirements of Station Batteries-Technical Specifications	8.3.2.2.2
	ETCSB8	Use of Diesel-Generator Sets for Peaking	8.3.1.1.2.4
	ETCSB10	Electrical and Mechanical Equipment Seismic Qualification Program	3.10, 8.3.2.2.1
	ETCSB11	Stability of Offsite Power Systems'	8.2.2.2
	ETCSB17	Diesel Generator Protective Trip Circuit Bypasses	8.3.1.1.2.8, Table 8.3-3a
	ETCSB21	Guidance for Applicable of Regulatory Guide 1.47	App. 3A (discussion of RG 1.47), 7.1.2.6
	ETCSB27	Design Criteria for Thermal Overload Protection for Motors of Motor-Operated Valves	App. 3A (discussion of RG 1.106), 8.3.1.1.4

8.2 OFFSITE POWER SYSTEM

8.2.1 DESCRIPTION

The SCE&G transmission system supplies offsite a-c power for operating the engineered safety features (ESF) buses as well as for startup and shutdown of the station. Two (2) separate sources of offsite power are provided for the Class 1E electric system, which is in compliance with General Design Criterion 17 and Regulatory Guide 1.32 (see Appendix 3A). One (1) source is the SCE&G transmission grid terminating at the Virgil C. Summer Nuclear Station 230 kV substation bus, which feeds the plant through a step down transformer. The second source is from the existing Parr Generating Complex over a 115 kV transmission line (see Figure 8.2-1). This source is connected to the plant through onsite step down transformers and a separate regulating transformer. These 2 sources have sufficient separation and isolation so that loss of the Virgil C. Summer Nuclear Station with the Fairfield Hydro Units off line will not degrade either of the sources below their acceptable voltage limit. Thus, loss of the station output, in conjunction with an accident, will not result in a degraded voltage condition on either source. Likewise, loss of a line or generation on the 115 kV network will not cause a degraded condition on the Emergency Auxiliary Transformer which is fed power from the 230 kV bus. Also, no single event such as an insulator or bushing failure, transformer failure, transmission line tower failure, line breakage, or similar event can cause simultaneous disruption of both sources. The offsite power system is not designed to withstand tornadoes, exceptionally severe hurricanes or ice storms. However, the circuit breakers for isolation of the 2 separate onsite power systems from the offsite power system are located within 2 separate, missile protected rooms. Therefore, any failure of the offsite power system, including the bus duct system between the offsite power system and the ESF buses, is isolated from the ESF buses before the emergency diesel generators are started (see Figure 8.2-2).

The allowable system voltage fluctuations for each of the 2 preferred offsite sources are defined in Table 8.2-2. As noted in the table, the allowable voltage range is dependent on generating unit availability, the number of buses connected to the source, and on the 98-01
configuration of the transformers for the 115 kV line. The SCE&G dispatchers are provided with instructions to make every effort to maintain the system voltage fluctuations within these allowable ranges. The instructions require maintenance of the voltage limits during shutdown, as well as during operation, of Virgil C. Summer Nuclear Station. The transmission system voltage drop due to loss of the Virgil C. Summer Nuclear Station is included within the allowable voltage ranges during plant operation modes 1 through 4 inclusive. The transmission system voltage drop is not included 00-01
within the allowable voltage ranges during plant operation modes 5 and 6 because the unit is already off line. A direct communications link is provided between the SCE&G Dispatch Office in Columbia, SC, and all SCE&G generating plants. Through this communications link, the plant operators receive the instructions from the dispatch office for setting generator kilowatt, kilovar output, voltage level, and for controlling the VAR output on the Fairfield units when they are used for pumping.

The plant operators are provided with indicators for the engineered safety features (ESF) bus network as discussed in Section 8.3.1.2.1. Also, voltmeters, ammeters, kilowatt meters, kilovar meters, and frequency meters are provided for the main generator bus. If generator output differs from that specified by the dispatch office, the operator notifies the dispatch office and receives a new set of operating levels for the generator.

Control and indication are provided locally at the substation and remotely in the system dispatcher's office for each of the incoming 230 kV transmission line circuit breakers and the 230 kV bus tie circuit breaker. Circuit breaker control consists of tripping and closing capability. Indication includes circuit breaker status (open or closed) and the amount and direction of the power being transmitted over each transmission line. Control power is supplied from a 125 VDC battery in the substation relay house, with a backup feed from the plant BOP battery for backup tripping power.

The 230 kV buses are protected by single phase bus differential voltage relays. Buses 2 and 3 are initially tied solid with provisions for adding a future breaker and relaying.

Each 230 kV line and the 115 kV line is protected by primary and backup relaying. Two (2) types of protection are utilized, depending on the length of the transmission line; (1) pilot wire and (2) carrier-directional comparison relaying. Both types provide primary and backup protection for the 230 kV transmission lines. The 115 kV line has directional distance relaying for primary protection and non-directional overcurrent relays for backup protection. Each 230 kV breaker is provided with a breaker failure relay that trips the appropriate bus lockout relay when the breaker fails to trip. Each line breaker also has a multi-shot, static reclosing relay.

The 230 kV circuit breakers associated with the plant main transformer and emergency auxiliary transformers, as well as the circuit switches associated with the ESF transformers, are controlled from, and provide indication in, the control room. Also, the 230 kV circuit breakers can be tripped at the circuit breaker control panels mounted on the circuit breaker structures.

Manually operated disconnect switches are provided for the 230 kV circuit breakers to isolate each from the bus and associated lines. These manual disconnects permit testing and maintenance of each circuit breaker on an individual basis while allowing the 230 kV substation to remain energized, which satisfies General Design Criterion 18. Testing and maintenance are performed periodically in accordance with a SCE&G program.

As shown by Figure 8.2-2, the 115 kV line terminates in a rigid bus construction for the crossover of the 230 kV middle bus section. The 115 kV bus has no connection to the 230 kV bus. Therefore, any problems associated with the 230 kV bus do not affect the 115 kV bus. The rigid bus construction offers high reliability by eliminating the possibility of line dropping at the crossover point.

The preferred power source transformers, which are the emergency auxiliary transformers and the combination of the safeguard transformers and the voltage regulator are located out of doors and are physically separated from each other. Lightning arrestors are used where applicable for lightning protection. The transformers are protected by automatic water spray systems to extinguish oil fires quickly, thus preventing spreading. The transformer area is provided with a gravel filled sump pit to contain transformer oil should a rupture occur.

Power from both the emergency auxiliary transformer and from the combination of the 2 safeguard transformers and the voltage regulator is brought into the plant by independent 7200 volt buses. These buses are physically separated and independently supported throughout their length to the 2 separated, missile protected rooms which contain the separate Class 1E electric system 7200 volt buses, thus maintaining redundancy.

8.2.1.1 Unit Auxiliary, Emergency Auxiliary, and Safeguards Transformers

Normal station service power for non-Class 1E equipment, which includes that required during normal operation, startup, shutdown, and following shutdown, is provided from the unit auxiliary transformer. The primary side of the unit auxiliary transformer is connected to the generator isolated phase bus duct at a point between the generator circuit breaker and the low voltage connections to the main step up transformer as shown by Figure 8.2-3.

The unit auxiliary transformer is rated 22 kV - 7200 volts. The three 7200 volt secondaries are used to feed 3 independent 7200 volt non-Class 1E auxiliary buses. The 2 ESF system 7200 volt buses are fed independently from other sources.

Two (2) emergency auxiliary transformers are provided. The primary sides of these 2 transformers are connected in parallel to the 230 kV substation bus. The 2 secondary windings on each bank are rated 7200 volts. Three (3) of the 4 windings are used as an emergency power source for the three 7200 volt non-Class 1E auxiliary system buses. The fourth winding is a preferred offsite power source for either or both of the ESF system power trains (see Figures 8.2-3 and 8.2-4). Normally this winding is used to supply the 7200 volt ESF bus 1DB.

The primary windings of the 2 safeguard transformers, XTF-4 and 5, are connected in parallel to the 115 kV line. These 2 transformers, in combination with the regulating transformer, XTF-6, are the second preferred offsite power source for either or both of the ESF system power trains. Normally, safeguard transformer 4 is used in combination with the voltage regulator to supply 7200 volt ESF system bus 1DA. If the voltage regulator is out of service, the 2 safeguard transformers can be used in parallel to supply either or both of the 7200 volt ESF system buses; or 1 of the 2 transformers can be used to supply 1 of the buses (see Figure 8.2-4).

Each of the 2 principle 7200 volt ESF buses is provided with a manually initiated transfer scheme to shift the bus power supply between the 2 preferred offsite power sources.

8.2.1.2 Transmission System

The network interconnections between the Virgil C. Summer Nuclear Station and the SCE&G transmission system consist of six 230 kV transmission lines which approach the site from 3 directions. The 230 kV transmission lines interconnect the Virgil C. Summer Nuclear Station with the major sources of generation on the SCE&G system through major transmission grid substations as shown by Figures 8.1-1 and 8.2-1. The lines are designed to meet or exceed NESC (ANSI-C2) 1973 edition, medium loading, grade B construction requirements.

In addition, two 230 kV transmission lines interconnect the Virgil C. Summer Nuclear Station with the South Carolina Public Service Authority (SCPSA) system.

In addition to the aforementioned lines, 2 transmission lines extend directly from the Virgil C. Summer Nuclear Station 230 kV bus section 3 to the SCE&G Fairfield Pumped Storage Facility.

One (1) 115 kV transmission line extends from the Virgil C. Summer Nuclear Station to the SCE&G Parr Generating Complex. The gas turbine generating and hydro power generating complex serves as one of the preferred power sources for the ESF buses at the Virgil C. Summer Nuclear Station. 98-01

The 115 kV transmission line has no direct ties to the Parr Generating Complex 230 kV substation. This substation does have a tie from the Virgil C. Summer Nuclear Station 230 kV substation bus. The Parr Generating Complex 115 kV substation bus receives power from the Parr Generating Complex and from a 115 kV tie line to the Denny Terrace substation. With this arrangement, an outage at the Virgil C. Summer Nuclear Station 230 kV substation does not have a direct effect on the 115 kV ESF transmission line.

Figures 8.2-2 and 8.2-2a through 8.2-2d indicate the physical relationship between transmission lines entering the switchyard, between the switchyard and the plant and within the switchyard. All 230 kV transmission tie lines to other major interconnection points converge on the substation. All transmission line structures have a minimum of 60 feet center to center as they approach the substation.

Each transmission line has adequate capacity for the supply of the preferred power source emergency auxiliary transformer. The 230 kV transmission lines, 230 kV circuit breakers and 230 kV buses in the substation are designed to withstand and interrupt the maximum fault level at the bus.

Details of the construction of each transmission line are as follows:

1. Parr-Summer Safeguard 115 kV Line

   This line is about 2.6 miles long. Wood, H-frame construction is used. The line extends from the Parr 115 kV substation to the vicinity of the Parr 230 kV substation and then to Virgil C. Summer Nuclear Station. It crosses over the double circuit Parr-Midway 115 kV, Parr-McMeekin 230 kV, and Parr-Denny Terrace 230 kV lines.

   There is a switchable tie to the Parr-Winnsboro No. 1 line. It also crosses over the Southern Railroad at Parr and over a railroad spur at Virgil C. Summer Nuclear Station. The last 2 line structures at Virgil C. Summer Station are double circuit, 230 kV towers. The other circuit is the Summer-Parr No. 2 230 kV line. There are no structure or circuit conflicts since a failure of the towers would not result in loss of both sources of offsite power, as the Parr Number 2 breaker would trip leaving the other 230 kV lines intact.

2. Summer Denny Terrace No. 1 Tie Line, 230 kV

   This line is about 2.5 miles long. At Virgil C. Summer Nuclear Station it is on 3 double circuit, 230 kV steel towers. The end of this line ties to the Parr-Denny Terrace 230 kV line about 1.2 miles from Parr. The tie line is of wood H-frame construction on a right-of-way with no other lines. It crosses over the two 115 kV lines to Winnsboro. At the tie, the Parr-Denny Terrace line is cut dead toward Parr and the tie line feeds toward Denny Terrace. This line then parallels (on existing right-of-way) the Parr-McMeekin 230 kV line for about 715 feet. There is a structure conflict in this area. The line crosses over the Lyles-Parr double circuit steel tower line, turns and parallels it to Denny Terrace, a distance of about 20.8 miles.

3. Summer-Parr (2 Circuits) Lines, 230 kV

Each of these 2 lines is about 2.3 miles long. They each occupy 1 side of three 230 kV, double circuit towers. Then each is on single circuit wood H-frames to the Parr 230 kV substation. They are on a common right-of-way. Summer-Parr No. 1 line is on a tower with space for a future circuit (none planned). The last 0.8 mile parallels the Parr-Midway 115 kV double circuit, steel tower line. The Summer-Parr No.1 line crosses over this double circuit steel tower line and the Southern Railroad at Parr. The Summer-Parr No. 2 line is on the same steel towers as the Parr-Summer Safeguard line at Virgil C. Summer Nuclear Station. There are no structure conflicts on this line after leaving the steel towers. It crosses over the Parr-Midway 115 kV double circuit, steel tower line and the Southern Railroad at Parr.

4. Summer-Pineland Line, 230 kV

This line is on 3 double circuit, steel towers with the Summer-Denny Terrace No. 2 line. These lines then are on wood H-frame structures designed for double circuits. The structures are in the center of a 240 foot wide right-of-way which extends for about 17.24 miles. In this area, the line parallels the SCPSA Summer-Blythewood 230 kV H-frame. There are structure conflicts in this area. For the next 1.62 miles, this line is on single circuit wood H-frame on a common right-of-way with the Summer-Denny Terrace No. 2 line. There are no structural conflicts in this area. For the next 5.0 miles, this line is on single circuit, wood H-frame on its own right-of-way. For about the final 0.54 mile, this line is on double circuit, improved appearance, steel poles at Pineland substation. This line crosses over several transmission lines but none cross over it. Total length is about 24.4 miles. 98-01

5. Summer-Denny Terrace No. 2 Line, 230 kV

This line is attached to the same structures as the Summer-Pineland line at the Virgil C. Summer Nuclear Station and for the first 17.24 miles. From this point the Summer-Denny Terrace No. 2 line is attached to single circuit H-frame structures and shares a common 240 foot right-of-way with the Summer-Pineland line for 1.62 miles. It is then on its own right-of-way for 5.91 miles. The Summer-Denny Terrace line then parallels the Denny Terrace-Rader double circuit 115 kV lines (crossing over them twice) to Denny Terrace, a distance of about 1.48 miles. Total length is 26.25 miles.

6. Summer-Graniteville Line, 230 kV

This line is on 3 steel towers at Virgil C. Summer Nuclear Station. It then parallels the Summer-Parr lines for about 0.6 mile and goes to the Broad River (a total distance of about 1.2 miles). It is paralleled by the SCPSA Summer-Newberry line. There are no structure conflicts in the H-frame portion of this line to this point. This line and the SCPSA Summer-Newberry line jointly occupy double circuit, steel towers across the Parr Reservoir on the Broad River and for the next 0.8 mile. For most of the remaining distance, this line is on its own right-of-way with no conflicts. It crosses over several different transmission lines (including those of other utilities). About 1 mile from Virgil C. Summer Nuclear Station this line passes under the double circuit Parr-Midway 115 kV and the double circuit Parr-Duke 230 kV lines. The supports for both lines are steel. The final 3.2 miles of this line parallel the Graniteville-Center 115 kV line. Each line is on separate H-frames and there is no structure conflict. Total line length is about 62.7 miles. | 98-01

7. South Carolina Public Service Authority, Summer-Blythewood Line, 230 kV

This line, built, operated and owned by SCPSA, is on the right-of-way with, and causes structure conflict with, the Summer-Pineland and Summer-Denny Terrace No. 2 lines for the first 17.24 miles. It is then on its own right-of-way to the Blythewood substation. Total length is about 23 miles.

8. South Carolina Public Service Authority, Summer-Newberry Line, 230 kV

This line is operated and owned by the SCPSA. It is on the same right-of-way as the Summer-Graniteville line to the Broad River but no structure conflict exists. (See the Summer-Graniteville line discussion.) It crosses the Broad River on double circuit towers. The next 0.8 mile is on double circuit steel towers with the Summer-Graniteville line. From that point the line goes to Newberry on its own right-of-way. Total length is about 17 miles. | 98-01

Distances of all lines from the Virgil C. Summer Nuclear Station terminal to the first major substation are listed in Table 8.2-1.

8.2.2 ANALYSIS

8.2.2.1 Introduction

The basis for design of SCE&G transmission facilities is such that a defined system will maintain stability with the simultaneous loss of any system generator, including Virgil C. Summer Nuclear Station, and the most critical transmission line associated with its loss. The system will also remain stable for the most severe fault condition on any transmission line or substation bus. As such, the loss of any single system generator, including Virgil C. Summer Nuclear Station, does not degrade the alternate system to where it cannot furnish shutdown power to Virgil C. Summer Nuclear Station on an

uninterrupted basis. The Virgil C. Summer Nuclear Station buses and the location of the emergency auxiliary transformers and ESF transformers supplying shutdown power are such that no single permanent fault condition can prevent at least 1 of the auxiliary transformers from being available to furnish shutdown power. Table 8.2-1 lists the distances of lines from Virgil C. Summer Substation to each first major substation.

8.2.2.2 Stability Study Results

Since the time of the last FSAR updated study in 1992, a number of changes have been made to SCE&G's generating and transmission systems. The system loads and operating configuration as modeled for the year 1998 were used as the basis of this study. In addition to system changes, the selection of cases for study was revised to more directly address NRC General Design Criterion 17. An additional objective of this study was to evaluate the Administrative Reactive Power Generation Limit of the V. C. Summer Nuclear Plant. Special attention was given to conditions in the vicinity of the V. C. Summer Nuclear Plant during system disturbances.

The SCE&G system was modeled both as peak load and off peak load cases with SCE&G generators operating as would be anticipated for the appropriate load conditions. In the peak load cases, the V. C. Summer generator was operating at an upgraded capacity of 1029.6 megawatts and 484 megavars. In the off peak load cases, the Fairfield Pumped Storage plant was operating in the pumping mode and the V. C. Summer generator was operating at 1029.6 megawatts and 254.0 megavars due to the reduced system load. In the peak load cases, all steam turbine generator units were represented as being in service, and no internal combustion turbines (ICT's) were considered to be in service, with the exception of the Hagood ICT. Hydro generation was varied according to system demand for the conditions studied in each case. All transmission system capacitor banks were operating in the peak load cases in accordance with the SCE&G practice of maintaining reserve reactive power generating capability whenever feasible. 98-01

LOSS OF GENERATION

Three (3) cases were simulated in order to evaluate the effects of the loss of generation on the SCE&G system. In the first case, all steam and hydro generation was on line except for Fairfield Pumped Storage Hydro Units 5-8. The first case simulated the loss of the V. C. Summer generator. The loss of the V. C. Summer generation resulted in decelerating forces which began to affect the generator rotor angles of SCE&G system and neighboring system machines on the order of 1 cycle. The effect on frequency deviations of SCE&G system machines was similar to the effect on generator rotor angles. The most responsive units were those located at the nearby Fairfield Pumped Storage Facility. All SCE&G system generators exhibited proper damping of frequency deviations as a result of governor action.

The # 2 and 3 buses at the V. C. Summer 230kV substation and a 115kV transmission line originating at the Parr substation supply the offsite power for the V. C. Summer Engineered Safeguard Features (ESF) buses. Power flows on the 230kV lines at the

V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

In the second case, all steam and hydro generation was on line except for Fairfield Pumped Storage Hydro Units 1 - 8. The second case also simulated the loss of the V. C. Summer generator. The loss of the V. C. Summer generator resulted in decelerating forces which began to affect the rotor angles of SCE&G and neighboring system machines on the order of 1 cycle. SCE&G system generator frequency deviations showed a time response similar to that of the rotor angles. The most responsive unit was located at the Cope plant. The next most affected units were those at the Parr Hydro facility. All SCE&G system generators exhibited proper damping of frequency deviations as a result of governor action.

Power flows on the 230kV lines at the V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay. 98-01

In the third case, all steam and hydro generation was on line with the exception of Saluda Hydro Units 1-5. The third case simulated the loss of McMeekin Unit # 2. The loss of the McMeekin # 2 generator resulted in decelerating forces which began to affect the rotor angles of SCE&G system and of neighboring system generators on the order of 1 cycle. SCE&G system generator frequency deviations showed a time response similar to that of the rotor angles. The most responsive unit was the remaining McMeekin # 1 generator. All SCE&G system generators exhibited proper damping of frequency deviations as a result of governor action.

Power flows on the 230kV lines at the V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0Hz, and 58.5 Hz with a 23 cycle time delay.

CRITICAL LINE OUTAGES

The three 230kV transmission lines which originate at the V. C. Summer substation bus # 1 share a common right of way for 17.3 miles. These transmission lines are the V. C. Summer-Pineland, V. C. Summer-Denny Terrace # 2, and the V. C. Summer-Blythewood tie line to the South Carolina Public Service Authority system. For the first case the fault was placed at the V. C. Summer substation bus # 1 to represent a fault shared by the 3 transmission lines at the V. C. Summer end of the common right of way. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The rotor angles of generators in neighboring systems were generally affected on the order of 1 - 2 cycles. Frequency deviations of SCE&G generators were observed within 1 cycle of the application of the fault. The most responsive units were those located at the Fairfield Pumped Storage Facility. The V. C. Summer generator responded in a manner similar to that of the Fairfield generators. All SCE&G system generators exhibited proper damping of frequency deviations as a result of governor action.

Power flows on the 230kV lines at the V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

The second case involving a critical line was for a fault at the V. C. Summer end of the V. C. Summer-Fairfield # 1 230kV line. Because this line is the sole connection to the system for the Fairfield Pumped Storage Units 1-4, a fault on this line along with the subsequent circuit breaker operation to clear the fault leaves with the generation of Fairfield Units 1-4 with no alternate route and results in the loss of generation for these units. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The effect of the fault and the subsequent opening of the 230kV line to clear the fault at Fairfield Pumped Storage Units 1-4 was extreme. Because this line is the only connection of these units to the system, the rotor angles of these units increased sharply with the resulting loss of synchronism of these units. It is not possible to determine the precise point in time of the removal of these units from the system. For the purposes of this study, they were allowed to remain connected as long as the simulation would continue to converge on a solution. In actual operation, these units would probably be removed from operation more quickly and therefore have less effect on the response of the remainder of the system. The rotor angles of generators in neighboring systems were generally affected on the order of 1 - 2 cycles. Frequency deviations of SCE&G generators were observed within 1 cycle of the application of the fault. As with the case of the rotor angle response, the frequency response of the Fairfield Pumped Storage Units 1-4 was extreme. All SCE&G system generators exhibited proper damping of frequency deviations as a result of governor action.

Power flows on the 230kV lines at the V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

The third case which examined the loss of a critical line was for a fault at the Denny Terrace end of the two 115kV lines from the Parr to Denny Terrace substations. Since the 2 lines share a common right of way for the entire distance, the fault was considered to interrupt both lines. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The rotor angles of generators in neighboring systems were affected on the order of 1 - 2 cycles. Frequency deviations of the SCE&G generators were observed within 1 cycle of the application of the fault. As would be expected, the most responsive units were those located at the Parr Hydro Plant. The frequency of the Parr generators began to increase while the 2 Parr-Deny Terrace 115kV lines were still open to clear the fault, and continued to increase after the lines were reclosed onto the fault. A period of damped oscillations then followed with a trend toward nominal frequency. The V. C. Summer generator also responded to the fault. Following the final circuit breaker operations at the Parr and Denny Terrace substations, the frequency oscillations of the V. C. Summer generator were damped with a trend toward nominal frequency. All SCE&G generators exhibited proper damping of frequency deviations as a result of governor action. 98-01

Power flows on the 230kV lines at the V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

The fourth case which examined the loss of a critical line was for a fault at the Parr end of the 115kV line from the Parr substation to the V. C. Summer offsite Power Supply bus. Since this line is the sole source for the V. C. Summer 115kV bus, a fault and the subsequent clearing of the fault by opening the Parr line breaker results in the loss of power to this bus. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 - 2 cycles. The rotor angles of generators in neighboring systems were generally affected on the order of 1 - 2 cycles. Frequency deviations of SCE&G generators were observed within 1 cycle of the application of the fault. As would be expected, the most responsive units were those located at the Parr Hydro Plant. The frequency of the Parr generators began to increase while the Parr-V. C. Summer 115kV line was still open to clear the fault, and continued to increase after the lines were reclosed onto the fault. A period of damped oscillations then followed with a trend toward nominal frequency. The V. C. Summer generator also responded to the fault. Following the final circuit breaker operation at the Parr substation, the frequency

oscillations of the V. C. Summer generator were damped with a trend toward nominal frequency. All SCE&G generators exhibited proper damping to frequency deviations as a result of governor action.

When the fault was applied at the Parr 115kV bus, the voltage at the V. C. Summer 115kV Offsite Power Supply bus immediately decreased to 0.00kV. Because the V. C. Summer 115kV Offsite Power Supply bus is served radially from the Parr 115kV bus, opening the line to clear the fault isolates the V. C. Summer 115kV bus from the SCE&G system. This resulted in the complete loss of voltage at the 115kV bus for the remainder of the simulation.

Power flows on the 230kV lines at the V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

For the fifth case a permanent fault was placed at the V. C. Summer substation bus # 1. Because the V. C. Summer generator is connected to the SCE&G system at the # 1 bus, opening the circuit breakers at the # 1 bus results in removing the V. C. Summer generator from the system. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The rotor angles of generators in neighboring systems were affected on the order of 1 - 2 cycles. Frequency deviations of the SCE&G generators were observed within 1 cycle of the application of the fault. The most responsive units were the 4 generators which were in service at the Fairfield Pumped Storage Plant. The next most responsive units were at the Parr Hydro Plant. All SCE&G generators exhibited proper damping of frequency deviations as a result of governor action.

Power flows on the 230kV lines at the V. C. Summer substation were below the rated capacity of each line throughout the period of study. No lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

For the sixth case, a permanent fault was placed at the V. C. Summer substation bus # 1 during light system load conditions and while the Fairfield Pumped Storage Facility was operating at its full capacity of 624 megawatts in the pumping mode. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The rotor angles of generators in neighboring systems were affected on the order of 1 - 2 cycles. Frequency deviations of SCE&G generators were observed within 1 cycle of the application of the fault. The most responsive units were the 8 generators at the Fairfield Pumped Storage Facility which were operating in the pumping mode and were therefore responding as large motors located near the fault. The next most

responsive units were at the McMeekin Plant. A period of irregular oscillation was followed by damped sinusoidal oscillations and a trend towards nominal frequency. All SCE&G generators exhibited proper damping of frequency deviations as a result of governor action.

Prior to the fault, the voltage at the V. C. Summer 230kV Offsite Power Supply bus was 232.28kV. Because the faulted 230kV bus is adjacent to the 230kV Offsite Power Supply bus, the voltage at the 230kV bus at the time of the fault was 0.00kV for the duration of the fault. This resulted in starting the loss of voltage and degraded voltage relay timers. The 230kV Offsite Power Supply bus voltage reached a minimum of 189.64kV during the period needed to reset the loss of voltage relay timer. This will result in a loss of voltage operation for the 230kV supplied buses.

Prior to the fault, the voltage at the V. C. Summer 115kV Offsite Power Supply bus was 117.09kV. Immediately before the removal of the fault, the 115kV bus voltage declined to 30.60kV. This resulted in starting the loss of voltage and degraded voltage relay timers. The 115kV Offsite Power Supply bus voltage reached a maximum of 100.37kV during the period needed to reset the loss of voltage relay timer. This will result in a loss of voltage operation for the 115kV supplied buses. The loss of both Offsite Power Supply buses is due to the load at the Fairfield Pumped Storage Facility during pumping operations at maximum plant pumping capacity. A proposed solution is examined in the seventh case.

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Power flows on the 230kV lines at the V. C. Summer substation were below the rated capacity of each line throughout the period of study with the exception of the 2 V. C. Summer-Fairfield lines. Both of these overloads are of short duration and are not expected to lead to a line outage. None of the other 230kV lines originating at the V. C. Summer substation experienced overloaded conditions. No lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3Hz, 59.0Hz, and 58.5 Hz with a 23 cycle time delay.

For the seventh case, a permanent fault was placed at the V. C. Summer substation bus # 1 during light system load conditions and while the Fairfield Pumped Storage Facility was operating in the pumping mode. In order to maximize the V. C. Summer 230kV and 115kV Engineering Safeguard Features bus voltages following the fault and bus differential operation, the two 230kV lines to the Fairfield plant were opened in order to remove the pumping load at the plant from the system. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The rotor angles of generators in neighboring systems were affected on the order of 1 - 2 cycles. Frequency deviations of SCE&G generators were observed within 1 cycle of the application of the fault. The most responsive units were the 2 generators located at McMeekin. The next most responsive unit was the generator at Cope. All SCE&G generators exhibited proper damping of frequency deviations as a result of governor action.

Prior to the fault, the voltage at the V. C. Summer 230kV Offsite Power Supply bus was 232.28kV. Since the faulted 230kV bus is adjacent to the 230kV Offsite Power Supply bus, the voltage at the 230kV bus at the time of the fault was 0.00kV for the duration of the fault. This resulted in starting the loss of voltage and degraded voltage relay timers. Immediately after the clearing of the fault and the opening of the 2 VCS-Fairfield 230kV lines, the 230kV Offsite Power Supply bus returned to 215.20kV. This enabled the loss of voltage degraded voltage relay timers to reset and prevent any voltage relay operations. The 230kV bus voltage increased to nominal levels and remained at approximately nominal voltage for the remainder of the simulation.

Prior to the fault, the voltage at the V. C. Summer 115kV Offsite Power Supply bus was 117.09kV. Immediately before the removal of the fault, the 115kV bus voltage declined to 30.60kV. This resulted in starting the loss of voltage and degraded voltage relay timers. One (1) cycle after clearing the fault and opening the 2 VCS-Fairfield 230kV lines, the voltage at the 115kV bus increased to 108.92kV. This enabled the loss of voltage and degraded voltage relay timers to reset and prevent any voltage operations. The 115kV bus voltage increased to nominal levels and approached pre-fault voltage levels during the remainder of the simulation.

Power flows on the 230kV lines at the V. C. Summer substation were below the rated capacity of each line throughout the period of study. No lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay. 98-01

For the eighth case, a permanent fault was placed at the V. C. Summer substation # 1 & 3 buses. Because the Fairfield Pumped Storage Facility is connected to the SCE&G system at the V. C. Summer # 2 & 3 buses, opening the circuit breakers at the # 2 & 3 buses results in removing all eight of the Fairfield generators with a total of 624 megawatts of pumping load from the system. The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The rotor angles of generators in neighboring systems were affected on the order of 1 - 2 cycles. Frequency deviations of SCE&G generators were observed within 1 cycle of the application of the fault. The most responsive unit was the V. C. Summer generator. The next most responsive units were at the Parr Hydro Plant. All SCE&G generators exhibited proper damping of frequency deviations as a result of governor action.

Prior to the fault, the voltage at the V. C. Summer 230kV Offsite Power Supply bus was 232.07kV. Since the faulted bus serves as the sole source for the 230kV Offsite Power Supply, the 230kV Offsite Power Supply bus voltage dropped to 0.00kV during the duration of the fault. Opening all circuit breakers at the # 2 & 3 buses isolated the 230kV Offsite Power Supply bus from the SCE&G system and resulted in a loss of voltage operation.

Prior to the fault, the voltage at the V. C. Summer 115kV Offsite Power Supply bus was 116.08kV. Immediately before the removal of the fault, the 115kV bus voltage declined to 35.91kV, resulting in starting the loss of voltage and degraded voltage relay timers. At the time of the removal of the fault, the voltage at the 115kV Offsite Power Supply bus increased to 101.38kV. This was sufficient to permit the loss of voltage relays to reset and prevent a loss of voltage operation. The 115kV bus voltage increased to 105.62kV which was sufficient to permit the degraded voltage relays to reset and prevent a degraded voltage operation.

Following the clearing of the fault, power flows on the V. C. Summer-Denny Terrace # 2 and the V. C. Summer-Blythewood 230kV lines briefly exceeded the thermal ratings of the lines. This was due to the oscillation of the V. C. Summer generator. As the V. C. Summer generator oscillations were damped, power flows on these lines dropped to below the thermal ratings of the lines within 23 cycles (at 1.5000 sec of study) and 20 cycles (at 1.4500 sec of study) respectively. Since the reverse third zone relays which monitor these lines are set for 125% of the line thermal ratings with a 1.5 second time delay, no circuit breaker action would be expected to occur. Power flows on the remaining 230kV line at the V. C. Summer substation were below the rated thermal capacity of the line. With the exception of the previously mentioned V. C. Summer-Blythewood 230kV line, no lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay. 98-01

<u>LOSS OF MAJOR LOAD</u>

The largest loads on the SCE&G system consist of the Fairfield Pumped Storage generators while operating in the pumping mode. Whenever pumping, the generators operate as motors with excitation systems but without governors. Each generator draws 78 megawatts at 1 per unit power factor. The Fairfield plant is connected radially to the V. C. Summer substation # 2 & 3 buses with 4 generators tied to each of the two 230kV transmission lines. A loss of 1 of the transmission lines would therefore result in the loss of as many as 4 generators for a total of 312 megawatts of load. This is the first contingency simulated.

The loss of 312 megawatts of load at the Fairfield plant affected the rotor angles of all generators in the SCE&G system with 1 - 2 cycles. The Rotor angles of generators in neighboring systems were generally affected on the order of 1 - 3 cycles although some generators showed no apparent affect of the loss of this amount load.

Frequency deviations of SCE&G generators were observed within 1 cycle of the loss of the 4 Fairfield units. The most responsive units were the 4 remaining generators at Fairfield which were operating in the pumping mode. The next most responsive unit was the generator at the V. C. Summer plant. All SCE&G generators exhibited proper damping of frequency as a result of governor action.

Prior to the loss of the Fairfield pumping load, the voltage at the V. C. Summer 230kV Offsite Power Supply bus was 232.28kV. Following the loss of load, the voltage reached a high of 234.531 kV and gradually decreased with very small long period oscillations throughout the remainder of the simulation with a final voltage of 232.67kV at the end of the simulation. The response of the 115kV Offsite Power Supply bus voltage was similar to that of the 230kV bus. The 115kV bus voltage was 117.09kV. Following the loss of load the voltage reached a high of 117.97kV and gradually decreased with very small long period oscillations throughout the remainder of the simulation with a final voltage of 117.25kV at the end of the simulation.

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Power flows on the 230kV lines at the V. C. Summer substation were all below the rated capacity of each line throughout the period of study. No tie lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

The second contingency studied was for a fault at the V. C. Summer # 2 and 3 buses. Because both of the 230kV lines connecting V. C. Summer to the Fairfield Pumped Storage Facility are connected to this bus, a bus differential operation at this bus results in the loss of the entire Fairfield pumping load of 624 megawatts.

The presence of the fault affected the rotor angles of all generators in the SCE&G system within 1 cycle. The rotor angles of generators in neighboring systems were affected on the order of 1 - 2 cycles.

Frequency deviations of SCE&G generators were observed within 1 cycle of the application of the fault. The most responsive unit was at the V. C. Summer plant. The next most responsive units were at the McMeekin plant. All SCE&G generators exhibited proper damping of frequency deviations as a result of governor action.

Prior to the fault, the voltage at the V. C. Summer 230kV Offsite Power Supply Bus was 232.28kV. Since the faulted bus serves as the sole source for the 230kV Offsite Power Supply, the 230 kV Offsite Power Supply bus voltage dropped to 0.00kV during the duration of the fault. Opening all circuit breakers at the # 2 and 3 buses isolated the 230kV Offsite Power Supply bus from the SC&EG system and resulted in a loss of voltage operation.

Prior to the fault, the voltage at the V. C. Summer 115kV Offsite Power Supply bus was 117.09kV. Upon the application of the fault, the 115kV bus voltage declined to 33.86kV, resulting in starting the loss of voltage and degraded voltage relay timers. Following the clearing of the fault, the 115kV bus voltage reached 107.07kV which was sufficient to reset the loss of voltage relay timer and prevent a loss of voltage relay operation. The voltage continued to increase and reached 108.33kV which was sufficient to reset the degraded voltage relay timer and prevent a degraded voltage relay operation. The 115kV bus voltage recovered to 115.31kV and remained above 115kV for the remainder of the simulation.

Following the outage of the # 2 and 3 buses, three 230kV transmission lines were left in service at the V. C. Summer substation. Two (2) of the lines overloaded briefly but not sufficiently to initiate circuit breaker operations. No lines connecting the SCE&G system with neighboring systems experienced overloaded conditions. SCE&G system and 98-01
neighboring system machine oscillations were damped with no indication of instability. No loss of load is to be expected with the present underfrequency relay settings of 59.3 Hz, 59.0 Hz, and 58.5 Hz with a 23 cycle time delay.

CONCLUSIONS

For the various contingencies which were simulated, the SCE&G system was evaluated with regards to generator frequency and rotor angle responses, as well as for tie line flows. Special attention was given to the effects of the contingencies on the operation of the V. C. Summer plant where the voltage responses of the 230kV and 115kV Offsite Power Supply buses and the loading of the transmission lines located at the V. C. Summer substation were examined.

The generator rotor angle responses in all cases demonstrated that no conditions existed in which system wide instability would develop. Neighboring system's generators responded to all contingencies in a stable manner.

None of the transmission lines connected to the V. C. Summer substation were found to trip due to overloaded conditions. In addition, all tie lines connecting the SCE&G system to neighboring systems remained in service throughout all conditions studied.

The voltage responses of the 230kV and 115kV Offsite Power Supply buses created the greatest concerns. None of the peak load cases resulted in loss of voltage or degraded voltage relay operations. However, in the off peak load case in which the V. C. Summer # 1 bus was faulted while the Fairfield Pumped Storage plant was operating in the pumping mode, the 230kV and 115kV Offsite Power Supply Bus voltages did not recover sufficiently during the allowed time interval to reset the undervoltage relay.

For this scenario to occur, all of the following conditions must be present:

1. The transmission system is lightly loaded.

2. The Fairfield Pumped Storage Plant is pumping at 1/2 or more of its rated capacity.

3. A fault occurs on the V. C. Summer substation # 1 bus. 98-01

A 1980 study by Gilbert/Commonwealth titled "Study to Determine the Probability of Loss of Off-Site Power to V. C. Summer Nuclear Station Unit" concluded that the failure rate of the 230kV bus is .0023/year or once in 432 years as a result of a natural phenomenon such as a tornado, hurricane, or an airplane crashing into the switchyard. The report also states that "the contribution to loss of offsite power from equipment failures is also random but readily quantifiable and is once in 3226 reactor years...".

The V. C. Summer unit is tripped by the # 1 bus differential operation or by the breaker failure operation. Consequently, the ability to keep the unit on-line during the contingency is not a consideration. The contingency condition still satisfies the requirements of GDC-17 and the FSAR Standard Review Plan for the offsite power supply to be available within a few seconds following a Loss of Coolant Accident and to maintain core cooling, containment integrity, and other vital safety functions.

8.2.3 REFERENCES

1. Institute of Electrical and Electronics Engineers, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations," IEEE-308-1971.

8.3 ONSITE POWER SYSTEMS

8.3.1 A-C POWER SYSTEMS

8.3.1.1 Description

The a-c power systems consist of the various auxiliary and engineered safety features electrical systems designed to provide reliable electrical power during all modes of station operation and under shutdown conditions. The a-c power systems are shown by Figures 8.2-3 and 8.2-4. The major electrical equipment is described in Table 8.3-1. Engineered safety features (ESF) auxiliaries are arranged so that loss of a single bus, for any reason, still leaves sufficient auxiliaries to safely perform required functions. In general, auxiliaries related to functions other than engineered safety features are connected to 3 auxiliary buses. A generator circuit breaker is provided to permit isolation of the generator from the system, which eliminates the necessity for a transfer from the emergency auxiliary transformer to the normal auxiliary transformer on plant startups. Engineered safety features loads are divided between 2 additional essential system buses in observance of the single failure criteria.

Controls are provided in the control room for selected 7200 volt and 480 volt switchgear units. These units are selected to provide the operator with control of the distribution network and remote control of selected loads.

8.3.1.1.1 Plant Distribution Network

1. 7200 Volt Network

   The 7200 volt network is arranged in 5 medium voltage primary bus sections. There are 2 additional medium voltage bus sections located in the Service Water Pumphouse. Each of these 2 buses is fed as a stub bus from the related ESF primary bus. Each bus consists of a separate, metal clad type, dead front construction, rated 7.2 kV nominal (8.25 kV max) volt, 500 MVA switchgear assembly. Each circuit breaker cubicle is isolated from the adjacent cubicle by metal barriers. Interrupting ratings for the switchgear breakers are 66 kA momentary, and 41 kA symmetrical at 6.6 kV, or 37.8 kA symmetrical at 7.2 kV (based on the symmetrical rating of 33 kA at 8.25 kV). These interrupting ratings are greater than any of the fault current levels on the various buses. Control power for tripping and closing the switchgear is obtained from the station batteries.

The 7200 volt buses 1A, 1B, and 1C supply power to non-safety-related auxiliaries. Each of these 3 buses supplies power to a reactor coolant pump. The normal power source for these buses is the main generator through the unit auxiliary transformer or back feed from the 230 kV bus through the main power transformer and unit auxiliary transformer. Upon tripping of the normal feeder breaker to these bus sections, the balance of plant (non-Class 1E) electrical system is automatically transferred to the emergency auxiliary transformers which are the emergency power sources. This automatic transfer is initiated when the normal feeder is tripped by main and unit transformer lockout relaying, generator differential protection relaying, generator and main transformer backup and field failure relaying, overall backup lockout relaying, and the condition of both the main transformer breaker and the generator breaker open. There is no automatic transfer when a bus over-current condition exists. Provisions are also available for manual transfer, as required.

In addition to the protective relays discussed above, there are 3 undervoltage sensing relays (1 for each phase) and 1 underfrequency sensing relay connected for each reactor coolant pump. These devices provide the reactor coolant pump undervoltage trip signal described in Section 7.2.1.1.2, Item 4.b, and the reactor coolant pump underfrequency trip signal described in Section 7.2.1.1.2, Item 4.c. These relays, together with the potential transformers from which they receive a voltage signal, are located in the reactor protection undervoltage and underfrequency relay panel. This panel is housed in the Seismic Category 1 Intermediate Building. Power feeds to the reactor coolant pumps are routed through this panel. Therefore, the voltage signal is sensed on the pump side of the supply circuit breaker.

To satisfy the single failure criteria, the panel is constructed in 3 sections, 1 section for each of the 3 reactor coolant pump power circuits. Each section is physically isolated from adjacent sections by a double, metal side sheet barrier. Any terminal blocks or fuse blocks mounted on a barrier side sheet are mounted on a polyester glass material. Polyester glass material is also placed under any wiring on a barrier side sheet. Thus, complete isolation of power cables, potential transformers and relays for each pump is maintained within the panel. The panel has been qualified to satisfy the requirements of IEEE-323[11] and IEEE-344[12]. Electrical separation of circuits associated with the reactor protection inputs is in accordance with the criteria outlined in Section 8.3.1.4.

The 7200 volt buses 1DA and 1DB supply power to the ESF equipment. These ESF buses provide an adequate and reliable source of electrical power for safe reactor shutdown under conditions resulting from any design basis event and/or during loss of offsite power, as well as for all modes of normal station operation. The normal and preferred power source for bus 1DA is the emergency auxiliary transformer XTF-4 in conjunction with the voltage regulator XTF-6. In the event that the voltage regulator is out of service, either or both of the 2 emergency auxiliary transformers, XTF-4 and XTF-5, can be used to supply bus 1DA. When the voltage regulator is out of service, parallel operation of the 2 transformers is preferred since it provides more flexibility and a greater range of allowable offsite voltage for the 115 kV system. The normal and preferred power source for bus 1DB is also the backup power supply for 1DA. In addition to the normal power sources, each 7200 volt ESF bus has an onsite emergency power source.

The physical layout of the cable bus system for connecting the 2 power transformers (emergency auxiliary and safeguard transformers) and the voltage regulator to the 7.2 kV ESF buses is shown by Figures 8.3-0 through 8.3-0g. Figure 8.3-0b.1 shows the modifications to the bus shown in Figure 8.3-0b for the addition of the voltage regulator and its by-pass switches. Location and physical separation between redundant portions of the Class 1E distribution equipment is shown in drawings maintained in the Virgil C. Summer Nuclear Station, "Fire Protection Evaluation"[13]. 00-01

Each onsite power source is capable of carrying the total ESF load required for safe shutdown. The onsite standby power system consists of 2 fully equipped diesel generators which provide 7200 volt power to buses 1DA and 1DB, respectively, within 10.25 seconds after detection of a loss of the associated 99-01 preferred power sources by loss of voltage relays and 13 seconds after detection of a degraded voltage condition. Buses 1DA and 1DB are provided with a manually initiated transfer to the alternate offsite power source.

Transfer switches are used to select power from 7.2 kV Channel A or Channel B sources for the C pump motors in the Service Water, Component Cooling and Safety Injection Systems. The switches are manually operated locally and are equipped with Kirk key interlock to prevent simultaneous closure of circuit breakers from both sources.

Speed switches are used to control the 2 speed, single winding motors used for the 3 component cooling water pumps.

2. 480 Volt Network

The 480 volt network distributes and controls power for all 480 volt and 120 volt a-c station demands. This network consists of 22 unit substations and 28 motor control centers. The unit substation switchgear is of metal clad, dead front construction, with 125 volt d-c operated air circuit breakers. Transformers for the 480 volt unit substations are air cooled and are directly connected to the switchgear. Except in special cases, motors rated above 50 hp to 350 hp are controlled directly by circuit breakers in the 480 volt switchgear. Motor control centers are used for control of motors 50 hp and smaller. 00-01

The maximum symmetrical interrupting capacity of the 480 volt motor control centers is 22,000 amperes. This interrupting capacity is greater than any of the fault levels on the motor control center buses. Current limiting reactors are provided in series with selected non-Class 1E motor control centers where the maximum symmetrical fault current that could otherwise occur at the motor control center would have exceeded 22,000 Amperes.

The maximum symmetrical interrupting capacity of the 480 volt unit substations is dependent upon the frame size of individual unit substation cubicles. In each case the interrupting capacity of a cubicle exceeds the maximum symmetrical fault current. Frame size rating and capacity is listed in Table 8.3-2.

a. Balance of Plant 480 Volt Network

The balance of plant 480 volt network consists of 18 unit substations and 18 motor control centers. Fifteen (15) of the unit substations are 4 wire, consisting of transformers and metal clad switchgear; 3 are 3 wire, consisting of transformers and power distribution panels. The 3 wire 480 volt unit substations provide power to the pressurizer heaters. Two (2) of these unit substations are connected to redundant safety-related (Class 1E) buses. These are loaded manually from the 7.2 Kv diesel generator buses 1DA and 1DB and furnish power to the 2 groups of heaters designated as backup groups. The third unit substation is connected to a balance-of-plant bus (1C) which powers the control group of heaters which are the normally energized heaters. Main feeder breakers for the 2 backup groups have been qualified in accordance with safety-grade equipment. Safety class heater cables and trays are protected by jet spray shields in the event of a PRT diaphragm rupture. Procedures for energizing the pressurizer heaters are addressed in Emergency Operating Procedures and System Operating Procedures as appropriate. These procedures describe (1) precautions to be observed if pressurizer heaters are to be used to prevent overloading diesel generators, (2) suggested loads to trim, (3) the time required to accomplish the connection. This time shall be consistent with the timely initiation and maintenance of natural circulation conditions. This meets the requirements of

NUREG-0578, Section 2.1.1, Position 3.1. All motor control centers are fed by 4 wire unit substations. The unit substations receive power from 7200 volt balance of plant buses 1A, 1B, and 1C through 7200 - 480/277 volt transformers. Each motor control center has a separate feed from the 480 volt unit substations. Selected motor control centers are provided with automatic transfer to an alternate power source.

b. Engineered Safety Features 480 Volt Network

The ESF 480 volt network consists of 6 unit substations and 9 motor control centers. The 480 volt ESF buses are fed through transformers with 7200 volt primaries and 480/277 volt secondaries which feed motor control centers, motors, and miscellaneous loads. These buses are independent from each other and there is neither automatic nor manual transfer capability. ESF 7200 - 480/277 volt transformers and switchgear are redundant and are located in separate areas of Seismic Category 1 structures to maintain isolation. ESF motor control centers are powered from the 480 volt ESF buses and have neither manual nor automatic transfer capability. The motor control centers are redundant and are located in separate areas of Seismic Category 1 structures or are separated by fire walls to maintain isolation. Under loss of offsite power conditions, power may be supplied to selected non-Class 1E 480 volt buses by the diesel generators. Equipment which is not safety-related but is considered essential for protection of the turbine or desired for convenience is manually activated by the operators.

The voltage fluctuates on the preferred sources within the limits defined in Table 8.2-2, as described in Section 8.2.1. Appendix 8D discusses the analytical method used for determining the optimum tap settings for the step down transformers in the plant distribution network. Also, included in the appendix is a tabulation of, or a referenced calculation for, the calculated voltages at the 7.2 kV and 480 volt distribution levels in the plant during light and accident load conditions with power being supplied from the offsite sources. The voltage fluctuation will be less than those given in Appendix 8E during diesel generator operation as the diesel's output is held to approximately + 0.5% of the voltage regulator's setting, and the regulator is set within the range of + 2%, - 5% of 7.2 kV. The light and accident condition loads were determined to be the worst case loads. The results indicate that with the design tap settings the motors terminal voltages will remain within the design limits of ± 10% of their rated voltages for the anticipated range of transmission system voltages. 00-01 00-01

If a degraded voltage occurs, with the established relay setting, the lowest voltage which could exist at a motor terminal is 90.0% of rated voltage (460 volts) and at a motor control center bus is 87.71% of rated voltage (480 Volts). 00-01

When the plant is at the startup stage and the design tap settings have been applied to the step down transformers, the voltages on the buses will be verified to ensure that they are not out of the range for proper equipment operation. Prior to fuel loading when the loads on the distribution system reflects the values to be expected during plant operation, the voltages and loads of the ESF system buses will be measured and the data used to verify the calculation of voltage levels. Appendix 8D discusses the calculation procedures and method of this verification of the calculation. Results were provided in a March 1, 1982 letter to the NRC. As part of the results, a tolerance study will be made and presented to show that the variations between the measured and calculated values are within the expected ranges.

The voltages on the buses are monitored during plant operation and recorded as part of operator logs to verify the proper range for equipment operation. 00-01

No load break, 480 volt a-c transfer switches are used to transfer power from 480 volt channel A or channel B sources for the motors for HVAC water chiller C and chilled water pump C. These switches are equipped with a walking beam interlock to prevent simultaneous closure of circuit breakers from both sources.

8.3.1.1.2 Onsite Standby Power Supplies

The onsite standby a-c power supplies for Virgil C. Summer Nuclear Station are 2, 12 cylinder, V configuration diesel engine driven generator sets. The generators operate at 514 rpm and provide 3 phase, 60 Hz, 7200 volt power. Each diesel generator has the following ratings:

1. Continuous, 4250 kW.

2. Short time, 4676 kW.

3. Overload (2000 hour), 4548 kW.

4. Seven (7) days, 4676 kW.

5. Thirty (30) minutes, 5100 kW.

The diesel generators are located in a building designed to satisfy Seismic Category 1 requirements and to protect the diesel generators against tornadoes, hurricanes and missiles. Within this building, the diesel generators, including associated starting equipment and other auxiliaries, are completely isolated from one another by a wall designed to withstand a safe shutdown earthquake (SSE).

Each diesel generator is provided with a separate, missile protected combustion air intake as shown by Figure 1.2-13 and a separate air discharge and engine exhaust. The diesel generators, together with associated fuel storage tanks, auxiliaries and related piping are designed to remain functional during an SSE and remain in a condition suitable for the performance of their function in shutting down and maintaining the plant in a safe condition.

Essential subsystems for each of the diesel generators and the physical arrangement of these subsystems are discussed in Sections 9.5.4 through 9.5.8.

8.3.1.1.2.1 Deleted by Amendment 98-01, April 1998

8.3.1.1.2.2 Deleted by Amendment 98-01, April 1998 98-01

8.3.1.1.2.3 Deleted by Amendment 98-01, April 1998

8.3.1.1.2.4 Diesel Generator Operation

Each 7200 volt ESF bus is continually energized from either the 230 kV or the 115 kV preferred power source transformer or from the onsite emergency diesel generators, as shown by Figures 8.2-2 and 8.2-3. The transfer from preferred power source to emergency diesel generator is accomplished automatically, when required, by the opening of the preferred power source air circuit breakers and closing of the emergency diesel generator air circuit breaker. The emergency buses and power supplies for all essential components are normally connected to the preferred offsite power sources.

The emergency diesel generators are automatically started upon receipt of an undervoltage signal from the associated bus from either the loss of voltage relays or degraded voltage relays, or upon receipt of a safety injection signal. They are also started upon receipt of a manually initiated signal from the control room. Loss of voltage on an ESF bus opens the normal or alternate supply circuit breaker (whichever is closed) and, when emergency diesel generator voltage and frequency are established, closes the emergency power source circuit breaker. In the case of a safety injection signal and/or ESF bus undervoltage, the ESF loading sequencer (see Section 7.3.1 for a detailed discussion) trips selected bus loads including all non-Class 1E loads. The bus is then reloaded in the sequence shown in Table 8.3-3, Parts A1 and B1. Items indicated by 0 second loading sequence in Table 8.3-3 are not tripped and, therefore, are immediately loaded when the emergency power source circuit breaker is closed. All other required loads are loaded in sequence by the ESF loading sequencer.

The 7.2 Kv ESF buses are each provided with 3 loss of voltage relays set at approximately 81% of the nominal bus voltage level and 3 degraded voltage relays set at approximately 91.34% of the nominal bus voltage level. Operation of a set of loss of voltage or degraded voltage relays will initiate a diesel generator start, a permissive for EFW turbine pump start, an ESF load sequence operation and a permissive for diesel generator circuit breaker close. These operations occur in a timed sequence as outlined in Table 8.3-5. The logic of the controls are illustrated in Figure 8.3-0o.

As illustrated in Table 8.3-5 the 7.2 Kv bus circuit breakers are tripped 4 seconds after the diesel generator is started on a degraded voltage condition as compared to 2 seconds for a loss of voltage condition. The delay in tripping for a degraded voltage condition allows the bus to be energized during the time the diesel generator is coming up to speed. Therefore, with the degraded voltage condition, the maximum dead bus time is 6 seconds as compared to a 10.25 seconds dead bus time allowed for a loss of voltage condition.

Appendix 8F provides a discussion of the time sequence of equipment operation with a degraded voltage condition coincident with an accident condition. When the diesel generators are started and loaded as a result of an undervoltage condition, the ESF loading sequencer logic prevents further undervoltage tripping of the safety related loads. When the buses are returned to the offsite power sources, the undervoltage tripping feature is automatically reinstated.

The emergency diesel generators and normal station service are synchronized only during periodic testing. Synchronizing capability is provided to reconnect the emergency diesel generators to the offsite power network when voltage is restored subsequent to the loss of offsite power. Synchronization is performed manually, when required. ESF equipment is duplicated on separate 7200 volt and 480 volt (as appropriate) buses as listed in Table 8.3-3, Parts A1 and B1. All equipment does not start simultaneously but is programmed to start automatically in sequenced steps. The first group, indicated by 0 load sequence seconds in Table 8.3-3, Parts A1 and B1, is connected to the ESF buses when the buses are energized. During recovery from step load increase, or from disconnection of the complete load, emergency diesel generator speed change will not exceed 75% of the difference between nominal speed and the overspeed trip setpoint or 115% of nominal speed, whichever is lower. Voltage is restored to within 10% and frequency to within 2% of the nominal values in less than 40% of each load sequence time interval. This complies with Regulatory Guide 1.9 (see Appendix 3A). Subsequent groups are each connected in sequence after short time delays.

The load profile after an accident, without offsite power, is generally outlined by Table 8.3-3, Parts A1 and B1. At no time following an accident will the load exceed the short time rating (110% of the continuous rating) of the diesel generators nor is it expected that the load will fall below 30% of the diesel generator rating.

In the event of an accident with offsite power available, the diesel generators will start and run at no load. Should a subsequent loss of offsite power occur, the diesel generators would be loaded automatically. If offsite power is not subsequently lost, the diesel generators would continue to run at no load until manually stopped by the operator.

The injection phase of a loss of coolant accident should not exceed 1 hour and the short term phase of a main steam line break accident is estimated to be 2 hours. Therefore, it is expected that both diesel generators can be stopped within 4 hours after an accident if offsite power is available. If the diesel generators are operated at no load or less than 20% load for a period of time longer than 4 hours, operating procedures will require paralleling of each machine with the bus and loading the generator to at least 50% of rated load. Only 1 diesel generator will be paralleled with a bus at a time.

Criteria discussed are conservative with respect to the manufacturer's recommendations (see Colt Industries, Fairbanks Morse Engine Division, "Operating and Maintenance Manual, South Carolina Electric and Gas Co., Virgil C. Summer Nuclear Station - Unit 1, Standby Diesel Generator Set," Colt-13-206152, Chapter 1, Tab 1, page 5-1) which, in part, are as follows: 98-01

> "In the event it is necessary to operate the engine for extended periods of time (over 24 hrs.) at from no load up to 20% of the engine rating, the engine should run 00-01
> at above 50% load for at least 1 hour in each 24 hour period in order to minimize 98-01
> the accumulation of products of combustion and lubricating products in the exhaust systems. Above 20% load rating, the engine may run continuously as required 00-01
> with the recommendation that the engine parameters be monitored closely and logged at least daily so as to be able to discover any problems early. (Changes in exhaust temperatures are of particular interest.)"

8.3.1.1.2.5 Diesel Generator Permissives

After the emergency diesel generator has received a starting signal, the following conditions must be satisfied before the generator is automatically connected to the ESF bus:

1. The diesel generator must be at approximately 90% of rated voltage and approximately 98% of rated frequency, based upon 2 out of 3 relaying schemes in each case.

2. The ESF bus normal and alternate power supply circuit breakers must be open.

3. There must be no electrical faults in the 7200 volt bus.

Figures 8.3-0h through 8.3-0j present diesel generator logic diagrams. Logic diagrams for the bus 1DA normal and alternate power supply circuit breakers are shown by Figures 8.3-0K and 8.3-0l. The bus 1DB normal and alternate supply circuit breakers use similar control schemes. | 98-01

8.3.1.1.2.6 Diesel Generator Testing

The diesel generators are tested as follows at the manufacturer's plant prior to shipment to the plant site:

1. The diesel generators are initially started and run in accordance with the manufacturer's standard procedure which includes the following:

   a. Operation at reduced RPM for approximately 50 minutes.

   b. Operation at rated RPM and variable load for approximately 6-1/2 hours.

2. The engine overspeed setting is tested and operation at 115% overspeed is demonstrated.

3. Diesel generator starting system capacity is demonstrated.

4. Diesel generator speed governing system is tested for steady state and transient performance, including load rejection tests at 25, 50, 75, and 100% of rated load.

5. The diesel generators are started and automatically loaded with a combination of resistive and inductive loads to simulate design loading conditions for the Virgil C. Summer Nuclear Station. This test is performed 10 times on each diesel generator.

6. The ability of the diesel generators to start and accept load without service water flow and without 480 volt auxiliary power is demonstrated.

7. The starting margin of each diesel generator is demonstrated by simultaneously starting and accelerating a 1750 horsepower motor and a 500 horsepower motor with the generator carrying a resistive load of approximately 50% of rated capacity.

8. Operation of the diesel generator in parallel with a utility system is demonstrated.

9. The diesel generators are operated at variable load for a total of 11 hours, including 3 hours at 100% of rated load followed by 2 hours at 110% of rated load.

Certified evidence is supplied by the manufacturer of the diesel generators that a total of 300 start and load tests, with a maximum of 3 failures, have been performed on a diesel generator of the design supplied for Virgil C. Summer Nuclear Station.

Each start and load test consisted of starting the diesel generator and applying load within 10 seconds after the start signal, increasing load to at least 50% of the continuous rating within 30 seconds and operating under load for a minimum of 5 minutes.

Some of these tests are initiated from design cold ambient conditions (keep warm temperatures) and some from hot equilibrium temperature conditions.

Tests and inspections are performed to ensure that all components are properly mounted, connections are correct, circuits are continuous and components are operational. Tests are performed to ensure that emergency loads do not exceed diesel generator rating and that each diesel generator is suitable for starting and operating required loads.

Proper operation of the onsite standby power supply is tested periodically. An availability test is performed periodically when the plant is in operation. Only 1 diesel generator is tested at a given time. The test consists of a manually initiated start of the diesel generator, followed by manual synchronization with and connection to the station ESF buses and assumption of load by the diesel generators. Normal station operation is not affected by this test. The operational test, automatic starting, load shedding and loading of the diesel generators, initiated by a simulated loss of voltage on the ESF buses are performed normally during reactor shutdown for refueling. Preoperational testing according to Regulatory Guide 1.41 is discussed in Chapter 14 and Appendix 3A.

8.3.1.1.2.7 Deleted by Amendment 98-01, April 1998 | 98-01

8.3.1.1.2.8 Instrumentation and Control Systems

Control power required for operation of each diesel generator is supplied from the 125 volt d-c distribution system. Control power for the diesel generator breaker to the ESF bus is supplied from the 125 volt d-c distribution system associated with the corresponding ESF bus. Controls are provided locally and in the control room for manual start and stop of each diesel generator. An automatic control system is provided for automatic startup and adjustment of speed and voltage to a ready-to-load condition.

A start diesel signal overrides all other operating modes and immediately returns the controls for the diesel generator to the emergency mode except under the following conditions:

1. Engine tripped due to overspeed.

2. Engine tripped due to low lube oil pressure.

3. Generator tripped due to generator differential relay operation.

4. When maintenance is in progress.

A matrix arrangement is provided for tripping the diesel generator for low lube oil pressure. This matrix consists of 4 pressure relays set at 70, 65, 60, and 60 psi. To cause a diesel generator trip due to low lube oil pressure, 2 of the low pressure switches must be activated and at least 1 of the 2 activated switches must be 1 of the 2 with 60 psi setpoints.

The other protective functions for the diesel generator are able to cause a diesel generator trip only during testing. Under emergency conditions, these protective functions actuate alarms only and do not trip the diesel generator.

Table 8.3-3a is a list of the protective devices provided for the diesel generators. This list also includes the function of these devices under emergency start and test start conditions.

Also, the engine manual stop pushbutton cannot override an ESF signal.

Instrumentation is provided locally and in the control room to monitor diesel generator frequency, voltage, loading and circuit breaker position.

Alarms are provided locally for all critical variables and trip functions as shown in Figure 8.3-0n. The local annunciator provides "first out" indication to aid in determining the cause of any trips or malfunctions. Alarms and status indication are also provided in the control room as shown in Figure 8.3-0m to indicate diesel generator status and permit remote operation of the diesel generators.

Most of the instrumentation is designed and installed to permit inplace calibration.

Logic diagrams for the diesel generator starting and shutdown controls are presented by Figures 8.3-0h and 8.3-0i.

8.3.1.1.2.9 Diesel Generator Environment

Combustion air for the diesel generators is taken directly from the outside through an intake which is completely independent of the ventilation air intake. The bottom of the ventilation air intake is located 29 feet above grade, as shown in the Figures 1.2-13 and 1.2-14. This high elevation will minimize the amount of dust taken in by the ventilation system. In addition, all cabinets containing control relays and associated devices have gasketed doors and openings. Therefore, the ventilation system will introduce a minimum of dust into the building and the controls are protected from whatever dust does enter the building.

There are several elements which interact to assure the cleanliness of the Diesel Generator Room and the supportive electronic and electrical components contained therein. They are as follows:

1. All electrical and electric component cabinets are weather sealed with rubber gaskets and have filtering media provided where air is circulated through the cabinets.

2. The Diesel Generator Building is to be designated as a Cleanliness Zone IV, which requires periodic inspections, specifically for cleanliness. 99-01

3. The mandatory surveillances for assuring the diesel's ability to start are supported by a periodic preventive maintenance task which requires inspection of the electrical and electronic components to determine operability and condition. Cleanliness is one of the areas that is inspected during the performance of the preventive maintenance task. 00-01

8.3.1.1.3 120 Volt A-C Vital Bus System

Six (6) 120 volt ac vital buses are provided. Each of 4 buses is supplied by 1 of 4 single phase static inverters. The normal feed to Panel APN5907 is from APN5901. The normal feed to Panel APN5908 is from APN 5903.

One (1) Channel A and 1 Channel D inverters are connected to ESF battery 1A, and 1 Channel B and 1 Channel E inverters are connected to ESF battery 1B.

The 120 volt ac vital buses constitute a reliable electrical system which provides a stable power supply to vital equipment and guarantees proper action when power is required while eliminating spurious shutdowns. Controls for the backup groups of heaters, the pressurizer level transmitters and for the pressurizer relief block valve operators receive their power from this vital ac bus source through the emergency power buses. The control power for the block valves is supplied from an emergency power bus different from that which supplies the associated PORV. Safety grade circuit breakers and fuses are used for circuit protection.

The normal source of power for the 120 volt ac vital bus inverters is through the inverter static rectifier. These inverter rectifiers are fed from 480 volt buses 1DA2 and 1DB2. The station batteries and battery chargers constitute the standby power source. The battery chargers are fed from 480 volt buses 1DA2 and 1DB2. In the event of loss of 480 volt power, the power source for the vital bus inverters is the station batteries. These batteries are floating, on standby service. The change in power source, from normal to standby, occurs without exceeding the stated inverter output voltage and frequency regulation. The station batteries are sized to carry this additional inverter load without being charged for no less than 4 hours. The battery chargers are sized to recharge from a design minimum charge to full charge in 12 hours while carrying the largest combined demand from the various steady-state loads. 99-01

An alternate power supply for the 120 volt ac vital buses is provided through 480-120 volt transformers from 480 volt buses 1DA2 and 1DB2 for use when the inverters are out of service.

8.3.1.1.4 Equipment Criteria

1. Motor Size

   The criterion for motor size is that the motor develops sufficient horsepower to drive the mechanical load under maximum expected flow and pressure. Motors are sized to permit the driven equipment to develop its specified capacity without exceeding the temperature rise rating of the motor when operated at the duty cycle of the driven equipment. Motors are furnished with service factors ranging from 1.0 to 1.15. The service factor is a ratio of the safe load to the nameplate load and identifies the margin available for motor operation under overload conditions. When a motor is furnished with a service factor greater than 1.0, it is the design intent to size the motor to handle the normal operating requirements of the driven equipment without taking credit for the service factor. Motor size is determined based on the driven equipment load characteristics. 00-01

2. Engineered Safety Features Motor Starting Torque

   Motors are designed for across the line starting. ESF motors rated 6900 volts are capable of accelerating the driven equipment to rated speed at 70% of the motor nameplate voltage. ESF motors rated 460 volts are capable of accelerating the driven equipment to rated speed at 80% of rated voltage, ± 5% of rated frequency or a combined variation in voltage and frequency of ± 10% of absolute values, provided that frequency variation does not exceed ± 5% of rated frequency.

Calculations based on the diesel generator factory test data indicate that the motor terminal voltage during starting will not go below 90% of the rated voltage for 6,900 volt motors or below 82% for 460 volt motors. The motor terminal voltage for the 6900 volt motors was calculated using the diesel generator voltage regulation for starting of a 1750 Hp motor. The motor terminal voltage for the 460 volt motors was calculated using the diesel generator voltage regulation for starting a 500 Hp motor and considering the voltage drop through the 7200/480 volt transformers. The actual largest system motors are 900 Hp and 350 Hp for the 7200 volt and 480 volt systems respectively (Refer to Appendix 8E). These voltage levels are well above those allowed by Regulatory Guide 1.9. The adequacy of bus voltage regulation during motor starting is confirmed during the preoperational testing program. 00-01 00-01

3. Motor Insulation

Motor insulation is a minimum of Class B outside the Reactor Building and Class F inside the Reactor Building. The insulation temperature rating is greater than the sum of the motor temperature rise and the ambient temperature at the motor location.

Service life is extended when necessary by 1, or a combination, of the following methods:

a. Derating - use of a larger motor than required by the motor sizing criteria previously discussed.

b. Insulation type - use of motor insulation with a higher temperature limit than specified for the operating conditions (e.g., specifying Class F insulation to Class B temperature limitations).

c. Service factor - motors with 1.15 service factor are operated under normal conditions without encroaching upon the service factor.

4. Engineered Safety Features Motor Temperature Protection

ESF motors rated 6900 volts and 600 hp and larger are provided with 6 stator winding embedded, resistance type, 10 ohm, copper at 25°C, resistance temperature detectors (RTD's). Smaller horsepower motors are not equipped with stator RTD's due to the problems involved in embedding them in the stator. The exceptions are the 400 hp reactor building spray pump motors which do have stator RTD's. 00-01

Motors rated 6900 volts and selected 460 volt motors are provided with bearing thermocouples. Outputs from each of the 2 motor temperature measuring devices are routed to the plant computer which actuates an alarm and provides a printed output if the stator RTD or bearing thermocouple measured value exceeds a predetermined setpoint.

5. Interrupting Capacity

Switchgear, unit substations, motor control centers and distribution panels are sized for interrupting capacity greater than the maximum short circuit availability at their location. The calculations to document this application take into account the fault contributions of all rotating machines and source transformers. Source impedances are selected to ensure adequate starting voltage for all motors and to limit short circuit currents at unit substation buses and motor control center buses.

6. Network Protection

Each major motor or other major item of electrical equipment is protected by overcurrent relays that disconnect the equipment if the load current becomes excessive. Prior to plant operation protective relays are set and calibrated. Availability and proper operation of standby equipment are periodically tested during normal operation.

The protection philosophy for the 7200 volt and 480 volt systems is based upon the following considerations:

a. A faulted piece of equipment is cleared by isolating the smallest possible portion of the system.

b. A faulted piece of equipment is cleared in the minimum possible time to reduce damage to that equipment and limit the stress on the remainder of the system.

c. Protective devices are selected and set for fault sensing and overload sensing as required for applicable system/component protection. 00-01

d. Motor control centers that serve loads located inside the Reactor Building typically have starters, (with thermal overloads) magnetic molded case circuit breakers, and a current limiting circuit breaker in series. The current limiting circuit breakers have thermal and magnetic elements incorporated in their protection circuit. Loads that do not require a starter, that use a contactor without overload protection, or have overloads bypassed under accident conditions, or are mentioned in Section 8.3.1.4.1; have an additional thermal element provided in the molded case circuit breaker. This arrangement provides primary and backup protection in compliance with Regulatory Guide 1.63 (see Appendix 3A).

e. Overload elements provided for safety-related valve operators are bypassed under accident conditions by the safety injection signal contact that initiates the valve operation. This is in compliance with Regulatory Guide 1.106 (see Appendix 3A).

7. Grounding Requirements

Design criteria for grounding of safety-related systems are as follows:

a. All equipment hardware, exposed surfaces and potential induced voltage hazards are adequately grounded to assure that no danger to plant personnel exists.

b. A low impedance ground return path is provided to facilitate the operation of ground fault detection or protective devices in the event of ground fault or insulation failure on any electrical load or circuit.

The following are the methods for grounding electrical equipment:

a. A ground wire is connected to the equipment frame and the ground grid. The ground wire is run through the equipment conduit or lashed to the power cable for the equipment where no conduit is provided. The wire is either connected directly to the ground grid or to other equipment, such as a cable tray which is connected to the grounding grid.

b. Where conduit is used as the grounding path, the conduit is connected to the equipment and the grounding grid. The connection to the grounding grid is either a direct connection or is connected to other equipment such as a cable tray which is connected to the grounding grid.

The cable tray system is solidly grounded. Ground connections are made to the station grounding grid or building steel work, which is connected to the station grounding grid.

The station grounding grid is designed to maintain the station area at an effective ground potential during a worst case ground fault in any installed electrical equipment, including transmission facilities and unit main generators, as well as lightning effects. An effective ground is considered to be the maintenance of voltage potentials below a "safe touch" level for plant personnel.

8. Maintenance Program

A maintenance program, in accordance with the recommendations of the manufacturers, is followed. This program includes periodic visual inspection and lubrication for each motor. A record is maintained for each motor indicating the date when each action is performed.

9. Starter Voltages

Starter coils for motor control centers are designed to pull in at 85% of rated voltage and to hold in at 65% of rated voltage. The coils are energized through a 480/120 volt instrument transformer.

10. Heat tracing is provided for Nuclear Safety Related and Non-Nuclear Safety Related equipment, piping, and/or tubing for the purpose of process temperature maintenance and freeze protection of liquids and for prevention of condensation in instrument air lines.

The heat tracing equipment protecting Safety Related systems (i.e., reactor makeup water storage tank and piping, refueling water storage tank and piping, and sodium hydroxide) includes redundant centralized control panels, temperature measuring equipment, wiring and conduit, and heat tracing cables, except for the refueling water storage tank and reactor makeup water storage tank. These tanks are monitored by redundant temperature instrumentation and are provided with 1 set of heat tracing each. Based upon the thermal capacity and insulated design of these tanks, the redundant instrumentation provides adequate operator control to prevent freezing. The centralized control panels provide power distribution, control and alarm functions from signals received from temperature measuring equipment attached to the piping systems. The primary and redundant heat trace circuits are each designed with the capability to provide the necessary freeze protection, or maintain the necessary process temperature. In the event of a failure to the primary heat trace circuit, the redundant heat trace circuit provides the necessary heat trace function. The heat tracing cables are of the parallel self-limiting type. The centralized control panels are powered from Class 1E Channel A and Channel B motor control centers. Alarms are transmitted to the control room from a local annunciator panel.

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8.3.1.2 Analysis

8.3.1.2.1 Compliance Analysis

The basic design criteria are that the Class 1E electric power systems satisfy the single failure criterion and Regulatory Guide 1.32 (see Appendix 3A). The safety-related loads are assigned to 2 independent, separate 7200 volt ESF buses. Either of these buses is capable of supplying required ESF or shutdown loads. Each of these buses is continuously energized from the preferred source ESF transformer(s), 1 set of windings in emergency auxiliary transformer (XTF-31), or from 1 of the diesel generators. Each 7200 volt ESF bus serves as a power source for the safety-related loads on the 480 volt buses and for equipment which is not safety-related but is considered essential for protection of the turbine or desired for convenience. This design, including the ties to the non-ESF buses, satisfies the independence and redundancy requirements of Regulatory Guide 1.6 (see Appendix 3A) and General Design Criterion 17.

The main control board is provided with indicators to monitor the ESF bus operating levels. A voltmeter, ammeter, wattmeter, varmeter and kilowatt hour meter are provided on each of the incoming, preferred power sources. The onsite power source has a voltmeter, frequency meter, wattmeter and ammeter provided on the main control board to indicate the ESF bus operating levels. Figures 8.2-3 and 8.2-4 indicate the metering provided on the plant electrical system. Table 8.3-3b is a listing of the indicator types associated with the ESF electrical network.

The ESF buses have sufficient redundancy to allow testing of each safety-related item as a system, or in some cases as individual components to comply with General Design Criteria 17 and 18.

Two (2) diesel generators provide onsite power to the 7200 volt ESF buses. Each diesel generator is assigned exclusively to 1 bus and each is automatically started upon a loss of bus voltage, degradation of bus voltage or receipt of a safety injection actuation signal. Under conditions outlined in Section 7.3.1, normal loads, with the exception of the group indicated by 0 seconds in Table 8.3-3 Parts A1 and B1, are | 98-01
disconnected and the ESF loads are automatically loaded in sequence on each diesel generator in accordance with the sequence presented in Table 8.3-3.

If a loss of preferred power is not concurrent with a postulated accident, certain ESF equipment is not required. Under these conditions, other plant auxiliary equipment may be manually operated. Safety injection loads are sequenced on by the load sequencer in this case, but loads are not disconnected prior to the sequencing. Instrumentation is provided to indicate emergency diesel generator loading.

The onsite standby power supply complies with Regulatory Guide 1.9, including load limits, (see Appendix 3A). The diesel generators have a continuous rating of 4250 kw, a short time rating of 4676 kw for up to 7 days, and a 30 minute rating of 5100 kw. The limiting accident load is calculated to be 4390 kw and the maximum load under loss of offsite power conditions is calculated to be 4920 kw. These short time and continuous rating loads are verified by test during each refueling outage. (The largest bus connected load is calculated to be approximately 5450 kVA.) 99-01

8.3.1.2.2 Hostile Environments

8.3.1.2.2.1 Equipment Identification

The most severe environmental conditions expected to be imposed upon the equipment which would operate inside and outside the Reactor Building during normal operation and subsequent to a LOCA or main steam line break are presented in Section 3.11. Regulatory Guide 1.89 is discussed in Appendix 3A.

8.3.1.2.2.2 Loss of Ventilation

To ensure that loss of the air conditioning and/or ventilation systems does not adversely affect the operability of safety-related control and electrical equipment located throughout the plant, the environmental systems for these areas satisfy the single failure criterion. Section 9.4 presents a detailed discussion of ventilation systems. Section 3.11.4 discusses loss of ventilation.

8.3.1.2.2.3 Qualification Tests

See Section 3.11 for a discussion of the hostile environment for which electrical equipment is procured and the maximum DBA environmental conditions to which it may be subjected.

8.3.1.3 <u>Conformance with Appropriate Quality Assurance Standards</u>

The quality assurance procedures used during equipment design, fabrication, shipment, field storage, field installation and system and component checkout and the records pertaining to each of these during the construction and preoperational test phases are described in Chapter 17.

The Quality Assurance Program, as discussed in Chapter 17, is in conformance with IEEE-336[1].

8.3.1.4 Independence of Redundant Systems

8.3.1.4.1 Criteria for Independence of Redundant Electric Systems

The electrical power supply, control and instrument cables for mutually redundant equipment are physically separated to preserve the redundancy and to ensure that no single, credible event will prevent operation of the associated function because of electrical conductor damage. Critical circuits and functions include power, control and instrumentation associated with reactor protection, ESF and reactor shutdown. Credible events include, but are not limited to, the effects of short circuits, pipe ruptures, fires, earthquakes, and missiles. The minimum electrical separation required for protection against design basis accidents is included in the basic plant design.

The separation of electrical circuits has been reviewed to the criteria of IEEE 384[14] as modified by Regulatory Guide 1.75 (see Appendix 3A). The plant design complies with these criteria as described below: 00-01

1. Redundant Class 1E circuits are run in separate and independent raceways. In general plant areas, not subject to hazards, such as missiles, open ventilated cable trays for redundant circuits are separated by a minimum of 3 feet horizontally or 5 feet vertically. In cable spreading rooms open ventilated cable trays are separated by a minimum of 1 foot horizontally or 3 feet vertically. Totally enclosed raceways for redundant circuits are separated by a minimum of 1 inch. Where these separation criteria cannot be satisfied, suitable barriers are placed between the raceways. The design of these barriers is described in Appendix 8B.

2. In areas where redundant circuits are exposed to hazards, such as missiles, the minimum spacing between mutually redundant wireways is 20 feet. Where this spacing cannot be achieved, a suitable missile proof barrier is used to ensure that no common hazard could render more than 1 mutually redundant circuit inoperative. Barriers have been provided to protect trays for Class 1E circuits from the effects of jet impingement and piping is restrained to prevent pipe whip as described in Section 3.6.

3. Where non-Class 1E circuits are connected to Class 1E equipment or are routed in the same raceways with Class 1E circuits, they are designated as associated circuits. Circuits designated as associated are routed with the designated separation channel throughout their length. Where non-Class 1E circuits are connected to Class 1E equipment, an isolation device is provided to protect the Class 1E equipment. These isolation devices are further discussed in Appendix 3A under the discussion of Regulatory Guide 1.75.

4. Non-Class 1E circuits are routed in raceways independent from the raceways for Class 1E circuits. Where the separation between the raceways for non-Class 1E circuits and raceways for Class 1E circuits do not satisfy the criteria for raceways carrying redundant Class 1E circuits, as described in Item 1, above, a case by case analysis has been performed to ensure that adequate separation exists. This analysis reviewed 2 types of violations, single and multiple. Single violations are those in which a non-1E tray violates the minimum separation required at one point along its path. These cases are summarized in Appendix 8C. A multiple violation is defined as a non-Class 1E tray which violates the minimum separation required at 1 point, and then, within the same fire area, the same non-Class 1E tray violates another Class 1E tray which is of a redundant channel to the initial 1E tray. For identified multiple violations in control (4000 series) trays, tray covers have been provided between the non-Class 1E tray and one of the Class 1E trays. The remaining violation is then analyzed as a single violation (Appendix 8C). For power trays (1000, 2000 and 3000 series) which cannot be covered, periodic testing of certain cable protective devices is performed in accordance with a controlled breaker surveillance program. This testing ensures that adequate overcurrent protection exists for the cables in the non-Class 1E trays so that they cannot be a hazard to the Class 1E trays whose separation distance has been violated. The results of the analysis for identified multiple violations are summarized in the Electrical Cable Separation Fire Barrier Identification Report S-200-951.

   All 5000 series instrument trays are deemed as acceptable barriers for multiple violations without the use of top hats, Kaowool, or any other fire related enhancements. Because of this, multiple violations in which 1 or more of the trays involved were 5000 series were classified as single or no violations as appropriate.

5. The Class 1E circuits routed to the service water intake structure are installed in underground concrete duct banks. These duct banks are seismic Category 1 structures and, as such, are designed to protect the cables from postulated natural phenomena, including SSE. The layout of the duct banks and associated manholes is illustrated by Figures 8.3-2a through 8.3-2g.

6. Separation of safety-related circuits is maintained in the electrical penetrations of the Reactor Building. Circuits for nuclear and protection instrumentation are not mixed with other type circuits in the same penetration. The redundant circuits for the 4 nuclear and protection instrumentation channels enter containment through penetrations located around the periphery with a minimum horizontal separation of 20 feet, centerline to centerline, between any 2 channels (see Figure 8.3-3). Physical separation between penetrations containing redundant circuits, other than the 4 nuclear instrument channels, is maintained in accordance with Section 8.3.1.4.3, Item 2.

The 4 penetrations containing the nuclear and protection instrumentation are provided with metal barriers. The metal barriers are used to separate the nuclear and protection instrumentation.

These barriers are grounded and are arranged to provide an effective electromagnetic shield over the full length of the penetration assembly.

Structural criteria require that penetrations be spaced on minimum horizontal and vertical centerlines as shown by Figure 8.3-3. This provides a 3 foot minimum separation between any electrical penetration and any other type of penetration. The design objective is to maintain maximum separation between safety related electrical penetrations and any large piping penetrations to minimize mechanical damage from the postulated rupture of steam or water lines. The design objective is also to maintain maximum separation between any safety-related penetrations and large power penetrations, such as those for reactor coolant pump or pressurizer heater power cables. Separation of safety-related electrical penetrations from main steam lines is maintained by a concrete floor or a minimum horizontal distance of 40 feet. One (1) exception is the penetrations for the power feeds to the Channel A Reactor Building cooling unit fans. The main steam lines and cooling unit fan power feeds both penetrate the Reactor Building above the operating floor. A 20 foot minimum separation is maintained between these penetrations. Separation from any other steam, high pressure water or large power electrical penetration is maintained by a concrete floor or by an 8 foot minimum horizontal centerline separation.

7. Cable trays, conduits and cables are marked for ready identification of the channel and to guard against violation of separation. Specific color coding is discussed in Section 8.3.1.5.

8. S-200-926, "Construction Guideline for Electrical Circuit Physical Separation," and Electrical Maintenance Procedure EMP-405.012, "Guide for Electrical Physical Separation," identity the minimum separation guidelines for internal wiring and components within control boards, panels, relay racks, etc. A minimum separation distance of 6 inches between redundant components and/or wiring and between Class 1E and non-Class 1E components and/or wiring within the enclosures is required. Where 6 inches of air separation is not available, a suitable fire barrier is installed or an analysis is performed to demonstrate that the separation distance is adequate. Design exceptions to the separation guidelines are addressed in Attachment 1 to S-200-926. 00-01

8.3.1.4.2 Compliance with Criteria for Independence of Redundant Electric Systems

A discussion of the administrative responsibility and control provided to ensure compliance with the criteria, set forth in Section 8.3.1.4.1, during design and installation is presented in Chapter 17.

8.3.1.4.3 Criteria for Design and Installation of Electrical Cable

The recommendations of IEEE Proposed Guide P-422,[3] IEEE STD 384[14], and Regulatory Guide 1.75 (see Appendix A) are used, except as modified by Items 1 through 6, below, as the general design criteria for the design of the power, control and instrument cable and cable tray systems related to all Class 1E electrical systems. 00-01

1. Power cable capacities are determined using derating factors listed in IPCEA P-46-426,[4] supplemented by IPCEA-NEMA P54-440.[5] Cable derating and cable tray fill are discussed in Section 8.3.3.1.

2. Cable routing in the Reactor Building, penetration areas, cable spreading room, control room, etc., is arranged following the recommendations in IEEE Proposed Guide P-422.[3] Channel separation and cable tray physical separation requirements are maintained in these areas in accordance with Section 8.3.1.4.1, item 6. Cables which must enter areas surrounded by shield walls are routed to minimize the cable length within the shields area.

3. Fire and/or smoke detection equipment is installed in areas of heavy cable concentration, as recommended by IEEE Proposed Guide P-422.[3] Fire stops are provided at cable tray penetrations through floors and fire barrier walls.

4. An exception is taken to IEEE Proposed Guide P-422[3] recommendations for 30% cable tray fill. Experience has indicated that a design objective of 50% physical fill, including all anticipated future cables, is satisfactory. This fill calculation is based upon the summation of the cable diameter squared divided by the cross-sectional area in the tray. The tables referred to in Item 1, above, are used as the basis for ampacity rating. The allowable depth is determined from the physical fill calculations outlined above and in Section 8.3.3.1.

5. The design objective for the minimum physical vertical spacing between the power, control and instrument cable trays of the same redundant channel is 12 inches, measured from the top of the lower tray to the bottom of the upper tray and a 9 inch clearance between the top of a tray and beams, piping, etc., to facilitate installation of cables in the tray. However, in areas where physical limitations govern, the physical separation may be less than the 12 inches and 9 inches, respectively.

6. The same basic design considerations are incorporated for tray and conduit supports as for the structures to which they are attached. Therefore, the same supports can be used for redundant raceways or for a redundant and non-safety raceway.

8.3.1.5 Physical Identification of Safety-Related Equipment

Identification of cable and raceways is readily apparent in the design and installation stages and is such that any safety-related cable can be readily identified. Raceways and cables (particularly for redundant systems) are adequately identified to prevent violation of separation criteria. Channel identification for safety-related and associated circuits is based upon the 4 reactor protection process control channel colors: red, orange, blue, and yellow. In addition, green is used for C train and tan is used for non-safety-related circuits. Cable trays and cables for these circuits, as well as for power, control and instrumentation circuits for ESF Channels A and B are identified relative to the 6 colors as indicated in Table 8.3-4. 00-01

Cable identification is as follows:

1. Color coding

   Cables are marked at 5 foot intervals. The circumference of the cable is marked such that the marking is visible no matter how the cable is turned.

2. Tagging

   Tags are placed at each end of the cable. These tags are marked to indicate the circuit and channel. Any nonengineered safety feature cables in a safety-related tray are marked to distinguish them from the safety-related cables.

3. Conduits

   Conduits are marked with identification markers. Color coding is done with colored tape at 15 foot intervals. Tags for embedded conduit are attached to the concrete above the conduit.

4. Cable Trays

   Cable trays for safety-related cables are identified with tags. The color coded tags are located on the trays so they are visible from easily accessible vantage points, such as walkways, etc.

5. Equipment Identification

Each piece of equipment has an identification (ID) tag attached which identifies the equipment. Channel designation for safety related and associated equipment is identified by a strip of color coded tape.

Tags mounted on equipment inside the Reactor Building are of stainless steel and have the required information engraved. Where there is not room to mount the tag to the equipment, it will be attached by wire. In these cases, the color coded tape will be attached to the back of the tag. Stainless steel ID tags are also used outside the Reactor Building. Tags for associated equipment have 2 colors.

8.3.1.6 Electrical Penetration Areas

Electrical penetration areas are located as follows:

1. Fuel Handling Building penetration area (penetration access area - North). Number of penetrations is 7. 00-01

2. Intermediate Building penetration area (penetration access area - East). Number of penetrations is 5.

3. Intermediate and Auxiliary Building penetration area (penetration access area - West). Number of penetrations is 33. 00-01

No special designations have been assigned areas where penetrations enter the Reactor Building.

Redundant circuits are spatially separated by 40 feet or a concrete floor, except for nuclear instrumentation penetrations, which are spatially separated by 20 feet.

Provisions for fire detection and protection in the penetration access areas consist of the following:

1. An early warning fire detection system comprised of smoke detectors.

2. A fire hose/standpipe system.

3. Manual fire extinguishers.

Protection to ensure that missiles inside the Reactor Building will not jeopardize plant safety are discussed in Section 3.5.1.

All containment penetration seal assemblies are protected against major incidents, such as missiles and rupture of high energy piping. Additionally safety related penetrations are protected on both sides of the nozzle. Therefore, based upon good design practice a separation of 3 feet from other penetrations, the failure of which could inflict only minor or insignificant damage to an electrical penetration, was provided.

8.3.2 D-C POWER SYSTEMS

8.3.2.1 Description

Separate Class 1E and non-Class 1E d-c power systems are provided. Two (2) Class 1E 125 volt d-c systems provide sources of reliable, uninterruptible d-c power for control and instrumentation for normal operation and orderly shutdown of ESF equipment. A separate non-Class 1E 125 volt d-c system is provided to supply non-ESF d-c loads, including large power non-ESF loads. This system is also a manually switched emergency backup d-c source for the 230 kV substation d-c system. In addition, a second separate non-Class 1E 125 volt d-c system is provided for 230 kV substation protection and control. These systems are shown in Figures 8.3-1, 8.3-2, 8.3-4, and 8.3-5.

The Class 1E d-c system for control and instrumentation consists of 2 full capacity, 125 volt d-c, lead calcium, 60 cell batteries, 2 125 volt d-c battery buses and 3 static battery chargers. Two (2) of the 3 battery chargers are supplied from separate, redundant motor control centers. One (1) of these 3 chargers serves as a standby charger and is provided for use during maintenance of, and to backup, either of the normal power supply chargers. The standby battery charger, 1A-1B, is provided with a set of 2 transfer switches which consist of mechanically interlocked circuit breakers on the a-c input and d-c output. These circuit breakers, as shown by Figures 8.3-6 and 8.3-7, are interlocked to allow only the 2 breakers associated with Channel A or the 2 breakers associated with Channel B to close at the same time. The battery chargers remain connected to the respective a-c source buses upon loss of offsite power. Each battery charger is protected by the molded case circuit breakers in the input and output circuits. The d-c circuit has a voltage adjustment of 100 to 145 volts d-c. During an equalizing charge, d-c voltage may be set at 140 volts. All Class 1E d-c loads can operate at 140 volts d-c without damage. An overvoltage alarm is provided to annunciate in the control room upon detection of voltages greater than 140 volts d-c.

The non-Class 1E d-c system for non-ESF loads and the backup d-c source for the 230 kV substation d-c system, consists of 1 125 volt d-c battery, 1 125 volt d-c bus and 2 static battery chargers connected in parallel. There are no safety-related loads connected to this battery.

The second non-Class 1E d-c system provided for the 230 kV substation control and relaying consists of a 125 volt battery with a battery bus, 2 static battery chargers and 2 separate distribution panels for power circuit breaker tripping. Backup for large power non-ESF loads is also provided by the system. 00-01

The non-Class 1E battery has adequate storage capacity to power the following loads for a period of 1 hour:

1. Main generator emergency seal oil pump.

2. Circuit breaker closing and tripping (non-ESF buses).

3. Miscellaneous non-ESF loads.

4. Non-ESF instrumentation inverter and computer inverter.

5. D-C turbine bearing oil pump.

6. Feedwater pump d-c oil pump (3 pumps).

7. Reactor and Diesel Generator Building emergency panels.

A 1 hour period is considered to be the minimum time for use in sizing the batteries. Complete loss of offsite and onsite a-c power for such a period of time is considered highly unlikely. Loss of both diesel generators during an assumed prolonged loss of offsite power is not postulated nor is complete loss of all battery chargers postulated. Battery chargers are considered to be available to sustain the bulk of the battery loads well within the 1 hour period of time.

The non-Class 1E battery supplying power to the d-c turbine bearing oil pumps is of sufficient capacity to power the pumps during turbine coastdown to avoid turbine bearing damage.

Battery capacity in addition to that which is absolutely essential is provided.

8.3.2.1.1 Uninterruptible Non-Class 1E System

The uninterruptible non-Class 1E 125 volt d-c system is an ungrounded system. The system is operated ungrounded with the battery floating on the system. Dual input inverter No. 5 (450 volt a-c normal input, 125 volt d-c backup input) provides uninterruptible 120 volt a-c power for the AMSAC system, secondary plant digital control systems, the station computer and other non-Class 1E loads. No Class 1E loads are supplied from this system.

The dual input inverter No. 5 provides continuous power to non-Class 1E 120 volt vital secondary digital control system and computer loads. Transfer from one input to the other is accomplished without interruption to the load. The inverter is protected by circuit breakers on the 480 volt a-c input side and the 125 volt d-c input side. Abnormal conditions in the dual input inverter cause alarms to occur in the control room. 00-01

The output of inverter No. 5 is connected to a distribution panel through an automatic static transfer switch. An alternate backup 480-120 volt transformer non-Class 1E power source is provided through the automatic static transfer switch. The feed to the transformer is from a 480 volt motor control center as indicated by Figures 8.3-4 and 8.3-4b. 00-01

All metering and monitoring is performed by a digital control system that includes a microprocessor. The operation of the microprocessor has no impact on the ability of inverter No. 5 to perform its function.

Inverter No. 6 is also powered from the non-Class 1E 125 volt d-c bus. A static switch is provided on the output of this inverter to switch the feed to the inverter distribution panel from the inverter output to a 120 volt a-c supply upon detection of loss of inverter output.

8.3.2.1.2 Uninterruptible Class 1E Systems

Each uninterruptible Class 1E system contains a separate 125 volt d-c and 120 volt a-c system.

The 125 volt d-c system is a 2 wire, ungrounded system centered around a full capacity 125 volt, lead calcium battery, 125 volt d-c main distribution panel and solid state battery chargers. Figures 8.3-2aa and 8.3-2ab show connection of the battery, battery charger and main distribution panel of each redundant Class 1E power system. No ties are provided between the redundant Class 1E 125 volt d-c systems. All non-Class 1E loads connected to the Class 1E d-c system are identified by Figure 8.3-1 (see Note 4, Figure 8.3-1). Connection of non-Class 1E loads to the Class 1E d-c system is discussed in the statement concerning Regulatory Guide 1.75 in Appendix 3A.

Eight (8) separate 125 volt d-c distribution panels including the 2 main distribution panels are provided. Each panel provides d-c instrumentation and control power as necessary for proper functioning of the plant.

The battery, battery charger and main distribution panel of each system are located in protected areas of the Intermediate Building, separate from the location of redundant channel equipment. The protected areas are separated by a fire resistant barrier. The inverters and other distribution panels are also located in protected areas.

Each ESF battery has a rated capacity of 2175 ampere hours (with an 8 hour discharge cycle to 1.75 volts per cell). This capacity is sufficient to power essential loads and normally connected non-essential loads for a 4 hour duty cycle following loss of all ac power. The 4 hour duty cycle is based on coping requirements for Station Blackout[15] defined by NUMARC 87-00[17] and endorsed by NRC Regulatory Guide 1.155[16]. The 4 hour duty cycle with loss of all ac power envelopes the previous 2 hour duty cycle based on a LOCA in conjunction with the loss of all ac. The 2 hour duty cycle represents

standard industry practice for sizing batteries for generating stations and does not reflect V. C. Summer design basis requirements for demonstrating dc system operability. Essential loads include the following:

1. Instrumentation inverters - with ESF and non-ESF loads.

2. Engineered safety features control.

3. Diesel generator control and field flashing.

4. Circuit breaker closing and tripping (ESF buses).

5. Controls and alarms, including Auxiliary Relay Racks, Isolator Cabinets, Main Control Boards, HVAC Boards and Control Room Annunciators.

6. Control Room emergency lighting.

During normal operation, the 125 volt dc load is supplied from the battery chargers with the batteries floating on the system. Upon loss of station ac power, the entire dc load is supplied from the batteries until the ac power to the chargers is restored by the emergency diesel generator or the preferred power source. The function of the battery is to provide sufficient stored energy to operate necessary dc loads for as long as each load is required during the loss of ac power. The time duration for the loss of ac power is the time required for the diesel generator to start and accept load. For the V. C. Summer Station, the diesel generator breaker will close and energize the battery charger within 10.25 seconds after a loss of ac power. Failure of a battery charger or failure of a diesel generator to start would be a single failure for which there is a redundant train of electrical systems that will be used to achieve safe shutdown and mitigate design basis events. A failure of a battery charger would not prevent either start of the diesel generator or closure of the necessary breakers to re-establish ac power to the auxiliary ac system. In the event of a charger failure, a backup charger has been provided and can be connected well within the battery's 4 hour duty cycle. Thus, the minimum 4 hour battery capacity provides considerable margin for the battery to perform its intended function.

Separate evaluations were performed to demonstrate sufficient battery capacity and to demonstrate system operability based on sufficient voltage at dc equipment/device terminals.

The evaluation to demonstrate sufficient Class 1E battery capacity was based on ampere loads associated with Class 1E and non-Class 1E equipment as shown on Figures 8.3-1, 8.3-2, 8.3-2aa, and 8.3-2ab. 00-01

The evaluation to demonstrate dc equipment/device operability was based on ensuring that the available operating voltage (or current) for required equipment was equal to or greater than the minimum operating voltage recommended by the applicable vendor or by actual tests to demonstrate component operability with margin. Available operating voltages (or currents in the case of D.G. field flashing) were evaluated to ensure operability of Class 1E devices based on the required time of operation and the applicable system losses resulting from voltage drop. Operability of non-Class 1E loads which are supplied from the 1A and 1B batteries was not evaluated.

System operating voltages were determined based on the battery as the sole source during the first 10.25 seconds following LOOP with only 59 cells or 58 cells connected. System operating voltages after 10.25 seconds were determined based on the battery at float voltage following restoration of ac power to the battery charger.

The evaluation conservatively determined voltage drop based on the dc load currents established by the battery capacity evaluation, as modified to include design margins, and the equivalent circuit resistance, as modified to compensate for worst case conductor temperatures.

Although there is no accident analysis that requires dc system operability with the battery as the sole source after 10.25 seconds, the design objective was to ensure the ESF 125v dc system is capable of supporting/operating normal and required emergency dc loads in the event of a DBA, or required SBO loads in the event of a 4 hour station blackout. Required SBO loads are normal (non-accident) loads necessary to ensure the reactor core is cooled and containment integrity is maintained in the event all ac power is lost for a 4 hour period.

8.3.2.1.3 Capacity

The ampere demand of each ESF battery was calculated for the loads listed in the preceding Items 1 through 6, as well as for other connected dc loads, to establish the worst case 4 hour duty cycle. This calculation resulted in the following 4 hour load profile.

1. Battery 1A – 376.9 amperes for the first minute, 200.3 amperes for the next 238 minutes, and 246.3 amperes for the last minute.

2. Battery 1B – 392.4 amperes for the first minute, 215.8 amperes for the next 238 minutes, and 261.8 amperes for the last minute. 00-01

The capacity of each ESF battery was then checked to ensure that the batteries are capable of supplying required dc loads for the duty cycle. In addition the battery capacity includes design margin, accounts for battery degradation with age, and considers the reduction of battery capacity due to temperature variations. The capacity

evaluation was based on a final (end of discharge) battery terminal voltage of 108V dc (or greater), which provides sufficient margin to ensure device operability with a reduction of up to 2 cells (58 cells connected) on either battery.

The calculated ampere demand includes normally connected devices with no distinction as to whether devices are required to operate or are desirable loads. The inclusion of the latter precludes the need for any load shedding and no operator action is required to maintain power to essential safety related loads during the 4 hour duty cycle. However, any load shedding performed during the battery duty cycle adds to the existing capacity margin and results in a higher battery voltage at the end of the duty cycle.

00-01

The d-c system is designed so that the loads with common a-c and d-c power supplies, such as inverters, are powered by the batteries during blackout, but are automatically returned to the a-c system upon a-c bus voltage restoration. As a result, the battery chargers are required to have a minimum capacity of 150 amperes to provide the necessary 12 hour recharge. This is well within the system's 300 ampere battery charger rating.

8.3.2.1.4 Ventilation

The battery rooms and battery charger rooms are located in the Intermediate Building and are provided (as a group) with a once through ventilation system consisting of two (2) 100% capacity supply fans and two (2) 100% capacity exhaust fans as shown in Figure 9.4-16. The ventilation system is designed for continuous operation. Therefore, the chance of producing an explosive atmosphere due to evolution of hydrogen during the process of battery charging is minimized. The system is provided with high and low temperature alarm inputs to the HVAC control board annunciator system. The battery room ventilation system is discussed further in Section 9.4.6.

8.3.2.1.5 Equipment

8.3.2.1.5.1 Batteries and Battery Racks

All batteries are of the central station, lead calcium type and are designed for continuous float duty. Each cell is of the sealed type, assembled in a shock absorbing clear plastic container, with covers bonded in place to form a leakproof seal. The batteries are mounted on protected, corrosion resistant, steel racks for security and to facilitate maintenance. The Class 1E batteries and racks are designed to remain functional during a safe shutdown earthquake and remain in a satisfactory condition to perform their function in shutting down the reactor and maintaining the station in a safe condition.

8.3.2.1.5.2 Battery Chargers

Each solid state battery charger has an output for float and equalize modes with an input of 480 volt 3-phase, a-c power. Each charger is equipped with a d-c voltmeter, d-c ammeter, a-c failure relay, a ground detection annunciator alarm, low battery voltage alarm relay and fan failure alarm. A battery charger malfunction activates an alarm in the control room. Each battery charger is designed to prevent the 480 volt a-c system from becoming a load on the battery as a result of loss of 480 volt a-c input.

Tests have verified that battery charger stability is not load dependent.

There is no annunciator to alarm when the battery charger goes into a current limiting condition.

In addition to the charger output ammeter, a 0 center scale ammeter is connected to a shunt in the leads between the battery and the battery bus to indicate current flow to and from the battery. These 2 ammeters show the status of battery charging or discharging currents and d-c system loads at all times. Main breakers, as shown on Figures 8.3-1, 8.3-2, and 8.3-4 are equipped with auxiliary switches to operate indicator lights in the control room for an off normal position. Thus, the operator is provided with system status information. Following a loss of normal station power, the battery chargers are energized from the diesel generators.

Additional monitoring is provided by a special, narrow band, d-c voltage relay to monitor Class 1E battery voltage. The relay initiates an alarm in the control room if battery voltage falls slightly below normal float voltage.

Voltage monitoring in this manner provides a backup alarm if a charger fails since a fully charged battery suffers a rapid drop in voltage if its floating charge fails. Such a rapid voltage drop causes the voltage monitoring relay to initiate the associated alarm. Battery ground detection annunciation is provided on the main control board for both Class 1E and non-Class 1E Plant d-c systems.

The ratings for each battery charger continuous output are as follows:

1. Charger 1A - 300 amperes
2. Charger 1B - 300 amperes
3. Charger 1A-B - 300 amperes
4. Charger 1X - 400 amperes
5. Charger 1X-2X - 400 amperes

Each battery charger has capacity adequate to restore its associated battery to full charge while providing power to the largest combination of the various steady-state loads. The charging capacity is based upon restoring the battery to full charge from the design minimum charge within 12 hours after discharge regardless of the status of the station.

8.3.2.1.5.3 Main D-C Distribution Panels

Each battery distribution switchboard consists of a metal clad structure with 125 volt d-c, 2 wire, ungrounded main bus. Two (2) pole, manually operated, air circuit breakers protect each feed. 00-01

8.3.2.1.5.4 Class 1E Dual Input Inverters

The dual input inverter in each system provides continuous power to the 120 volt vital a-c buses. The output of the inverter is a regulated supply. Transfer from 1 input to the other is accomplished without interruption of the output. Each inverter is protected by circuit breakers on the 480 volt a-c input side, 120 volt vital a-c output side and 125 volt d-c input side. Each dual input inverter is provided with an a-c and a d-c ammeter. Abnormal conditions in the dual input inverter, including loss of a-c input, loss of d-c input, and loss of a-c output voltage cause alarms to occur in the control room.

The output of each inverter is connected to a distribution cabinet through an automatic static transfer switch and a normally closed circuit breaker. An alternate backup 480-120 volt transformer Class 1E power source is provided through the automatic static transfer switch. The feed to the transformers is from a 480 volt motor control center as indicated by Figures 8.3-1 and 8.3-2. The distribution cabinets have appropriately sized branch circuit breakers to feed reactor protection and other vital 99-01 instrument channels. Most reactor protective schemes have 3 or 4 channels. Redundant instrument channels are fed from redundant vital buses.

Because of the preferred failure mode defined for the reactor protective instrumentation, failure of an instrument channel power source results in a reactor trip signal from the affected channel. Multiple power supplies are provided to prevent a single power supply failure from initiating a false reactor trip.

The vital bus rectifiers and inverters are assembled from high quality components, conservatively designed for long life and continuous operation.

By avoiding the use of electromechanical devices, routine maintenance downtime is greatly reduced. There are no vacuum tubes or moving parts in the completely static vital bus supply systems.

The ratings of each inverter are as follows:

1. Inverter No. 1 - 10 kVA.

2. Inverter No. 2 - 10 kVA.

3. Inverter No. 3 - 10 kVA.

4. Inverter No. 4 - 10 kVA.

8.3.2.1.5.5 Non-Class 1E Inverters

There are 2 non-Class 1E (balance of plant) inverters. Inverter No. 5 is a dual input inverter. The dual input inverter No. 5 provides continuous power to non-Class 1E 120 volt vital digital control systems and computer loads. Transfer from one input to the other is accomplished without interruption to the load. The output of inverter No. 5 is connected to a distribution panel through an automatic static transfer switch. An alternate backup 120 volt non-Class 1E power source is provided through the automatic static transfer switch. The AMSAC system, secondary plant digital control systems and the station computer constitutes the primary loads on this inverter. 00-01

Inverter No. 6 is a single input inverter supplied from the 125 volt d-c non-ESF system. Output from this inverter is paralleled with a supply from a 480-120 volt transformer which is connected, through a static transfer switch to the inverter main distribution panel. The transformer source serves as an alternate supply to the inverter main distribution panel. Upon loss of inverter output, automatic transfer of the inverter main distribution panel to the alternate supply is initiated. The primary load on inverter No. 6 is non-ESF instrumentation.

An alternate power source circuit breaker is provided in the distribution cabinet to permit manual transfer from the inverter or transformer power source to a backup power source as indicated by Figure 8.3-4.

Inverter ratings are as follows:

1. Inverter No. 5 - 10.0 kVA. 00-01

2. Inverter No. 6 - 10.0 kVA.

8.3.2.1.5.6 480-120 Transformer and Static Transfer Switch

An alternate source of power to each of the 120 volt vital a-c buses is provided by a 480-120 volt Class 1E, single phase transformer. The 480-120 volt transformer in each system is designed to supply the total 120 volt vital a-c bus load when the dual input inverter is out of service.

A static transfer switch is provided for inverter No. 6 to switch the 120 volt vital a-c bus loads from the single input inverter to the 480-120 volt transformer. The static transfer switch is a solid state device. Its operation is unaffected by load and power factor variations. Transfer of the 120 volt vital a-c bus loads from the single input inverter to the 480-120 volt transformer causes an alarm to occur in the control room. Transfer back to the inverter is performed manually at the discretion of the operator.

8.3.2.1.5.7 Nominal 120 Volt Vital A-C Bus System

The nominal 120 volt a-c vital bus system consists of 6 panels and 4 inverters which provide power to 4 independent channels of ESF instrumentations. Channels A and B consist of 2 panels and 1 inverter each while Channels C and D consist of 1 panel and 1 inverter each. Figures 8.3-1, 8.3-2, 8.3-2aa, and 8.3-2ab depict the system.

The vital bus system is a very reliable electrical system. It provides a stable supply to vital equipment and guarantees proper action when power is required, while eliminating spurious shutdowns.

The normal power source for each vital bus inverter is through the inverter static rectifier from a 480 volt ESF bus. Should the normal power source fail completely or be subject to transient voltage or frequency variations, the vital bus inverter power source becomes the battery charger or battery which is floating on standby service. This transition from static rectifier to battery power supply takes place without disturbing vital bus voltage or frequency. The station batteries are sized to carry this additional inverter load without chargers for no less than 4 hours. The chargers are sized to bring a fully discharged battery up to equalize charge voltage with the inverter load connected in 12 hours.

8.3.2.2 Analysis

8.3.2.2.1 Compliance

The Class 1E uninterruptible systems satisfy the criteria of Regulatory Guides 1.6 and 1.32 (see Appendix 3A), and General Design Criteria 17 and 18. The uninterruptible systems are designed so no action, automatic or manual, needs to be taken to make d-c or vital a-c power available to the equipment required immediately following LOCA or after a loss of a-c power. No operator action is required to maintain d-c or vital a-c power availability, based on single failure criteria, for safe shutdown or accident mitigation following a loss of a-c power.

Class 1E system components are identified and seismically qualified as described in Section 3.10. The battery was connected to a resistive load of approximately 20 amperes during seismic testing.

Class 1E equipment and the hostile environment to which it is subjected are discussed in Section 3.11.

Each uninterruptible system includes power sources and a distribution system arranged to provide power to associated system loads. No ties exist between Class 1E systems. Figures 8.3-1, 8.3-2, 8.3-2aa, and 8.3-2ab illustrate the independence of the Class 1E uninterruptible systems. Equipment, cables and other components are designed, identified and located in accordance with the criteria given herein. Sections 8.3.1.4 and 8.3.1.5 discuss general design criteria applicable to the uninterruptible systems as well as to the a-c systems.

8.3.2.2.2 Maintenance and Testing

The uninterruptible systems are subjected to periodic maintenance tests to determine the condition of each individual component. Batteries are checked for electrolyte level, specific gravity, cell voltage and visual signs of deterioration. A battery performance discharge test is performed according to IEEE-450[7]. Battery chargers, and inverters are checked by visual inspection weekly and performance tests are conducted periodically.

Maintenance and testing procedures for batteries are in accordance with IEEE-450[7]. Testing and inspection are performed according to the following:

1. General inspections and recording of data are performed in accordance with IEEE-450[7].

2. Quarterly tests, inspections, and recording of data are performed in accordance with IEEE-450[7].

3. Yearly inspections are performed in accordance with IEEE-450[7].

4. Battery service tests are performed in accordance with IEEE-450[7]. The time interval between tests is based on a nominal 18 month refueling outage schedule. Service tests are not performed during outages that require performance of a capacity (performance discharge) test. (See Regulatory Guide 1.32 discussion in Appendix 3A.) 00-01

5. Battery capacity tests are performed in accordance with IEEE-450[7] and IEEE-308[8].

8.3.2.3 <u>Physical Identification of Safety-Related Equipment</u>

The physical identification of safety-related equipment is discussed in Section 8.3.1.5.

8.3.3 FIRE PROTECTION FOR CABLE SYSTEMS

The 8000 volt rated power cable, 600 volt rated power cable for 480 volt and 120 volt a-c systems and 125 volt d-c systems, 600 volt rated control cable for 120 volt a-c and 125 volt d-c controls and 300 volt instrument cable are constructed with an overall fire retardant outer jacket.

Cable for external circuits is type tested in accordance with Section 2.5 (Flame Tests) of IEEE-383[9] and the cables are certified to be of fire retardant construction.

8.3.3.1 Cable Derating, Cable Tray Fill, and Cable Construction

Cables are derated to compensate for ambient temperatures and for the presence of adjacent power cables. Power cables are sized and derated on the basis of IPCEA P-46-426[4], supplemented by IPCEA-NEMA P54-440[5].

Motor feeders, power panel feeds and small lighting and receptacle panel transformer feeds are sized for 125% of full load current. Large power transformer feeders are sized for 140% of full load current at maximum rating. Motor control center feeders are sized for 140% of the calculated normal diversified load current. Feeders to resistive loads are sized on the basis of 110% of rated current at rated voltage.

In selecting IPCEA ampacity tables, a load factor of 100% is assumed.

Ampacities of 7200 volt power cables are in accordance with IPCEA P-46-426[4] in air ratings, derated by factors of 0.70 in 40°C areas and 0.63 in 50°C areas.

Ampacities of 480 volt cables or large d-c cables in single layer power trays are in accordance with IPCEA P-46-426[4] in air ratings and are derated by factors of 0.70 in 40°C areas and 0.63 in 50°C areas.

Ampacities of 480 volt cables or d-c cables in a random lay power tray are in accordance with IPCEA-NEMA P-54-440[5]. Derating factors for 3 inch depth are used.

Ampacities of small 480 volt cables or small 125 volt d-c cables (#10 AWG and smaller), when run in control trays, are in accordance with IPCEA P-46-426[4] in air ratings derated by a factor of 0.50.

Ampacities for 7.2kV and 480V 3 conductor cables in conduit wrapped in Kaowool at 40°C ambient temperature are calculated to ensure a maximum copper surface temperature of 90°C. Basis for these calculations are data obtained from IPCEA P-46-426. The application ampacities of the cables are determined by applying a 1.25 derating factor to the design ampacities. The cable sizes are then selected so that the cable application ampacity is equal to or greater than the design current value determined from the cable sizing criteria. 00-01

No ampacity derating factors are applied to control and instrument cables.

Ampacities are determined on the basis of 90°C tables at 40°C ambient in all interior areas except containment. Containment or ESF motors in areas requiring forced ventilation of the motor are determined on the basis of 50°C ambient.

Pressurizer heater cables are sized by special ratings due to the operating environment.

The Reactor Building cooling unit fan motor power cables and the post accident hydrogen recombiner unit power cables[10] require special consideration since these motors must operate in the post accident containment environment. These cables are sized to carry the required current during the post accident temperature and pressure transient without exceeding the recommended emergency operating temperature rating for the cable and to continue to operate for a minimum of 6 months after the accident.

A preventive maintenance program to test the insulation values of circuits and equipment is followed.

Ladder type tray systems are used for power and control trays. Instrument trays are solid bottom trays with top cover plates.

The 5 basic tray systems are as follows:

1. The 7200 volt power trays.

2. The 480 volt and below, single layer power trays.

3. The 480 volt and below, random lay power trays.

4. Control trays.

5. Instrument trays.

In vertical stacking the 7200 volt power trays are on top, 480 volt power trays next lower, control trays next lower, and instrument trays on the bottom.

8.3.3.1.1 7200 Volt Power Trays

No other type cable is mixed in the same tray with 7200 volt power cable. These trays are 4 inches deep (inside dimension). There is 1 layer of cable with no spacing between cables.

8.3.3.1.2 480 Volt and Below, Single Layer Power Trays

The 480 volt and below, single layer power tray system is exclusively for 480 volt, 3-conductor power cables or d-c power cables. This tray system is 4 inches deep (inside dimensions) and contains only large (MCM sizes) and 4/0 cables. There is 1 layer of cables with no spacing between cables.

8.3.3.1.3 480 Volt and Below, Random Lay Power Trays

The 480 volt and below, random lay power cable tray is for 480 volt power cables 4/0 and smaller. The tray is 6 inches deep (inside dimensions).

$$\text{Percent fill} = \frac{\left(d_1^2+d_2^2+\ldots+d_n^2\right)x100}{\text{Tray Depth x Tray Width}}$$

where: $d_1, d_2, \ldots . d_n$ = Diameters of all cables in the tray presently planned plus all known future cables.

Small 480 volt power cables (#10 AWG and smaller) may be run either in the random lay power cable tray or the control tray. Circumstances may dictate running an MCM size power cable in a random lay power tray. The cable is then derated with the derating factor appropriate to the random lay trays.

8.3.3.1.4 Control Trays

The control trays contain control cables, small 480 volt power cables (#10 AWG and smaller, except for selected motor operated valves which use larger sized cables) and small d-c power cables (#10 AWG and smaller). All of these cables carry either intermittent current or continuous current of 5 Amps or less. Single phase, 120 volt a-c circuits (#10 AWG and smaller) carrying 5 amps or less may also be run in the control trays. The amount of heat generated from cables which carry intermittent current is negligible based on the large majority of time the load is not operating. 00-01

The control trays are 6 inches deep (inside dimensions). The design limit for control tray fill is based on verifying that the weight of new and existing cable is within the tray and tray support weight capability.

8.3.3.1.5 Instrument Trays

Instrument trays contain low level analog signals cables. These trays are 6 inches deep (inside dimensions). The design limit for instrument tray fill is based on verifying that the weight of new and existing cable is within the tray and tray support weight capability. 00-01 In addition to all low level analog signal cables, the instrument trays are used for digital contact (breaker contact) cables where the source of power is the reactor protection or computer packages, otherwise all digital circuits are in the control trays.

8.3.3.1.6 Cable Tray Fill Criteria

The 50% cable tray fill criteria is the design objective that applies only to random lay power trays. Random lay power trays contain 480 volt power cables smaller than MCM sizes. Power cables, No. 10 and smaller, may be run either in random lay power tray or in control tray. 00-01

The 30% fill criteria recommendation in IEEE Propose Guide P-422[3] is based upon the summation of cross sectional areas of cables. The 50% fill noted in Section 8.3.1.4.3 is based upon the summation of the cable diameter squared areas. Fill of 50% on this basis is equivalent to 39% fill on the IEEE Propose Guide P-422[3] basis (i.e., 3.1416/4.0 times 50%). Through experience, it has been found that approximately 40% fill on the basis of cross sectional area or 50% fill on the basis of diameter squared area is satisfactory with respect to physical tray loading and uses the tray more efficiently. 00-01 00-01

Power cables are rated on the basis of this 3 inch physical depth, using the derating factors of IPCEA-NEMA P-54-440[5].

These derating factors are in agreement with the 50% or 3 inch depth physical loading. Control and instrument cables require no derating.

Where random lay power tray fill exceeds 50%, worst case conditions have been analyzed to assure the capability of the tray hangers to support the additional weight and, that sufficient margin exists in the cable sizing to account for the heating effects (Reference IEEE Transaction Paper 70TP557PWR "Ampacities for Cables in Randomly Filled Trays", also, see FSAR Section 8A.1.2). For each random lay power tray, a calculation was performed to address the additional heat loading from the new power cable and its effect on the ampacity (heat loading) of other power cables in that tray. The existing and new power cables were derated if the total heat loading of the cables in the tray was not within the allowable heat loading based on the percent fill. In addition, this calculation determined the weight of the new and existing cables to ensure that their combined weight was less than the maximum weight that the tray support can carry. For trays filled to the maximum weight allowed by the tray supports, the maximum allowable cable sidewall pressures will not be exceeded (Reference FSAR Section 8A.1.3). In the event overfill occurs at tray intersections, protection will be provided to preclude cable damage. 00-01

The cable tray fill criteria for control and instrument trays is controlled by the cable management system computer program. This program contains an alarm limit for the maximum weight allowed for each tray size used. Therefore, manual calculations to monitor cable weight are not required since this calculation is done by the cable management system and an alarm is provided if the tray or tray support weight capability is exceeded. Heat loading is not a concern for control and instrumentation cables due to their small currents and/or intermittent operation.

For expanded cable and tray design considerations, see Appendix 8A.

8.3.3.1.7 Cable Construction

Feeder and motor cables in 7200 volt service are insulated cables rated at a minimum of 8000 volts. Single conductor cables or each conductor of multi-conductor cables in 7200 volt service are shielded.

Power cables for 480 volt service are insulated cable rated at a minimum of 600 volts. Single conductor cables and multi-conductor cables are provided with an overall flame retardant jacket.

Control cables are of single or multi-conductor construction with a 600 volt (minimum) insulation, total coverage electrostatic shield and overall flame retardant jacket.

Low voltage instrument cables are insulated cables rated at 300 volts, minimum. Where required, these cables are provided with a total coverage electrostatic shield and with an overall flame retardant jacket.

8.3.3.2 Fire Detection and Protection Devices

Fire detection and protection systems, either automatically or manually initiated, are provided in those areas required to preserve the integrity of circuits for redundant safety-related systems. A fixed, low pressure carbon dioxide fire extinguishing system is installed in the relay room and computer room at elevation 436' of the Control Building. A preaction sprinkler system is installed in the following areas of the Control Building:

1. Cable spreading room - elevation 425'.

2. Cable spreading room - elevation 448'.

3. Cable chase areas.

Smoke detection systems are installed in the switchgear rooms and penetration access areas. Section 9.5.1 provides greater detail concerning fire detection and protection.

The fire hazard to cables is reduced by cable construction as described in Section 8.3.3.1.7. 00-01

8.3.3.3 Fire Barriers and Separation Between Redundant Cable Trays

Criteria used for the separation between different Class 1E system trays and between Class 1E and non-Class 1E trays are given in Section 8.3.1.4. Where the required separation cannot be maintained, fire barriers are installed in accordance with IEEE P-422[3], Section 8.3.2. The fire barriers are qualified in accordance with criteria given in Section 9.5.1.

In cases of multiple separation violations between non-safety related trays and redundant safety related trays in the same fire area, tray covers or circuit breaker surveillance has been provided as a resolution. Refer to FSAR Section 8.3.1.4.1, item 4 for details.

8.3.3.4 Fire Stops

Openings in walls, floors, and ceilings, which are provided for the routing of raceways, are protected by fire stops. Fire stops are designed with a fire rating equivalent to that required for the wall, floor or ceiling with which it is associated. The materials used in fabricating fire stops are rated in accordance with ASTM E 119. In addition to preventing the spread of fire, fire stops are designed to be reasonably leaktight, thereby limiting the propagation of smoke and gases from one area to another.

8.3.4 SAFETY RELATED CABLE

No natural polyethylene materials are used in safety related inter-connecting circuits between equipment in the Virgil C. Summer Nuclear Station. Cables which have cross linked polyethylene are used for various plant applications.

8.3.5 REFERENCES

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2. Deleted (RN 99-037) 00-01

3. Institute of Electrical and Electronics Engineers, "Design and Installation of Cable Systems in Power Generation Stations," IEEE Proposed Guide P-422, prepared by the Working Group on Wire and Cable Systems Station Design Subcommittee, Power Generation Committee. 00-01

4. Insulated Power Cable Engineers Association, "Power Cable Ampacities," IPCEA P-46-426-1962.

5. Insulated Power Cable Engineers Association - National Electrical Manufacturers Association, "Ampacities of Cables in Open-Top Cable Trays," IPCEA-NEMA P-54-440.

6. Institute of Electrical and Electronics Engineers, "Guide for Class 1E Control Switch Boards for Nuclear Power Generating Stations," IEEE-420-1973.

7. Institute of Electrical and Electronics Engineers, "Recommended Practice for Maintenance, Testing, and Replacement of Large Stationary Type Power Plant and Substation Lead Storage Batteries," IEEE-450-1987. 98-01

8. Institute of Electrical and Electronics Engineers, "Criteria for Class 1E Electric Systems for Nuclear Power Generating Systems," IEEE-308-1971.

9. Institute of Electrical and Electronics Engineers, "Standard for Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations," IEEE-383-1974.

10. "Electric Hydrogen Recombiner for PWR Containments," WCAP-7709-L, Supplement 7, (Proprietary) and WCAP-7820, Supplement 7 (non-Proprietary), August, 1977.

11. Institute of Electrical and Electronics Engineers, "Qualifying Class 1E Electric Equipment for Nuclear Power Generating Stations, General Guide," IEEE-323-1971.

12. Institute of Electrical and Electronics Engineers, "Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," IEEE-344-1975.

13. Virgil C. Summer Nuclear Station, FPER. 00-01

14. Institute of Electrical and Electronics Engineers, "Criteria for Separation of Class 1E Equipment and Circuits," IEEE-384, 1974.

15. 10 CFR Part 50, Section 50.63, "Loss of all Alternating Current Power."

16. U. S. Nuclear Regulatory Commission Regulatory Guide 1.155, "Station Blackout."

17. NUMARC 87-00, Nuclear Management and Resources Council, Inc., "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactor."

18. Calculation No. DC08500-022, "Determination of Maximum Sidewall Pressure Imposed on Cable in Cable Tray as a Result of Cable Weight." 00-01

TABLE 8.3.1

MAJOR ELECTRICAL EQUIPMENT

Equipment	Tag Numbers	Description and ratings	
Unit Generator	XGN1-EG	1, 101, 300 KVA, 0.90 pf, 22 kV, 1800 rpm, 3ϕ, 60 Hz	
Standby Diesel Generator	XEG0001A, B-E (Engine) XEG0001A, B-G (Generator)	4250 KW. 7.2 KV, 0.8 pf, 3ϕ, 60 Hz	
Main Transformer	XTF1-EG	940/1052.8 MVA, 55C/65C FOA, 242-22 kV, 3ϕ, 60 Hz	00-01
Unit Auxiliary Transformer	XTF2-ES	48/64 MVA, 55C 22-7.2/7.2/7.2kV	
Emergency Auxiliary Transformer	XTF31-ES XTF32-ES	24/32/40/44.8 MVA, 55/55/55/65 with nominal 8.0% impedance from HV to LV, based upon 24 MVA base, 230-7.2/7.2kV	
Engineered Safety Transformer	XTF4-ES XTF5-ES	10/12.5/14 MVA, 115/7.2 kV	
7.2 kV Line Voltage Regulator	XTF6-ES	1500 kVA, 55° C rise, Class OA, 7.2 kV $\pm$ 10% in 32 - 5/8% steps, 1200 Amps, 1.12% based on 15 MVA, 3ϕ, 60 Hz	00-01
Generator Circuit Breaker	XCB10A-EG, XCB10B-EG, XCB10C-EG	1ϕ, 60 Hz, 22 kV (nominal) 36 kV (max), interrupting rating of 100 kA (sym) and 146 KA (asym).	

TABLE 8.3-2

SYMMETRICAL INTERRUPTING CAPACITY FOR
480 VOLT UNIT SUBSTATION CUBICLES

	Symmetrical Interrupting Capacity	
Frame Size (amps)	Instantaneous Trip (amps)	Delayed Trip (amps)
600	30,000	22,000
1600	50,000	50,000
2000	65,000	55,000
3000	65,000	65,000

TABLE 8.3-3a

DIESEL GENERATOR PROTECTIVE DEVICES

Device	Protective Relay Function if Diesel Start is Initiated By: ESF OR Undervoltage	Test Start Switch	
67 DG Motoring - reverse power flow	Alarm	Trip (2)	99-01
51 DG Ground Overcurrent	Alarm	Trip (2)	
51VDG Time overcurrent - voltage controlled	Alarm	Trip (2)	
46 DG Negative phase sequence	Alarm	Trip (2)	
64 FDG Field ground relay	Alarm	Alarm	
87 DG Generator differential	Trip (3)	Trip (3)	
40 DG Field failure relay	Alarm	Trip (2)	99-01
Lube oil pressure low (4 switches)	Trip (1) (3)	Trip (3)	
Engine overspeed	Trip (3)	Trip (3)	
Crankcase pressure high	Alarm	Trip (3)	
Lube Oil temperature high	Alarm	Trip (3)	
Jacket coolant temperature high	Alarm	Trip (3)	
59 Overvoltage	Alarm	Alarm	
Fuel Oil Pressure Low	Alarm	Alarm	
Start failure	Alarm	Alarm	99-01
Barring Device Engaged	Prevent Start	Prevent start	

Note:

1. Trip occurs on actuation of 2 of 4 switches if at least 1 of the 2 actuated switches has setpoint of 60 psi. Setpoints are at 70, 65, 60, and 60 psi.

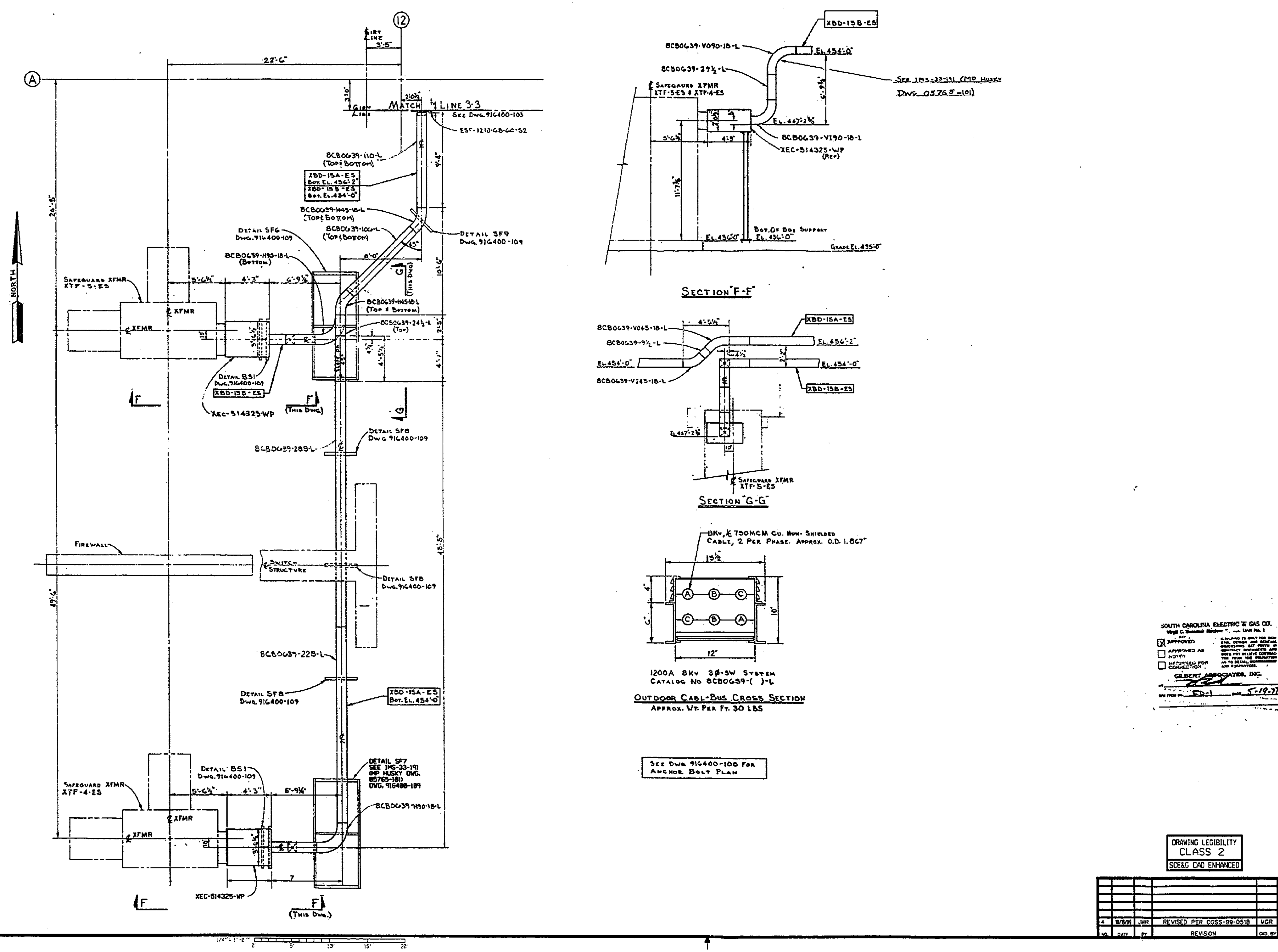
2. Trips Diesel Generator Breaker only.

3. Trips Diesel Generator Breaker and Diesel Generator Engine.

TABLE 8.3-3b

ENGINEERED SAFETY FEATURES BUS INDICATORS

Indicator Type	Function	Location
GE Type AB-40, Frequency Meter	Diesel generator A, frequency	Main Control Board (MCB) panel XCP6117
GE Type AB-40, A-C Wattmeter	Diesel generator A, watts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	Diesel generator A, volts	MCB panel XCP6117
GE Type AB-40, A-C Wattmeter	ESF transformer, watts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	ESF bus 1DA, volts	MCB panel XCP6117
GE Type AB-40, A-C Varmeter	ESF transformer, vars	MCB panel XCP6117
GE Type 180, A-C Ammeter	Diesel generator A, amperes	MCB panel XCP6117
GE Type 180, A-C Ammeter	ESF transformer, amperes	MCB panel XCP6117
GE Type 180, A-C Ammeter	7.2 kV bus 1DA feeder, amperes	MCB panel XCP6117
GE Type AB-40, Frequency Meter	Diesel generator B, frequency	MCB panel XCP6117
GE Type AB-40, A-C Wattmeter	Diesel generator B, watts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	Diesel generator B, volts	MCB panel XCP6117
GE Type AB-40, A-C Voltmeter	7.2 kV bus 1DB, volts	MCB panel XCP6117
GE Type 180, A-C Ammeter	Diesel generator B, amperes	MCB panel XCP6117
GE Type 180, A-C Ammeter	7.2 kV bus 1DB feeder, amperes	MCB panel XCP6117
GE Type AB-40, A-C Ammeter	7.2 kV bus tie 1DX2DX, amperes	MCB panel XCP6117 00-01
GE Type AB-40, A-C Voltmeter	115 kV incoming, volts	MCB panel XCP6117



AMENDMENT 00-01
DECEMBER 2000

DRAWING LEGIBILITY CLASS 2
SCE&G CAD ENHANCED

FSAR Figure 8.3-0b

OUTDOOR CABLE BUS LAYOUT & SECTIONS
SAFEGUARD TRANSFORMER AREA
HUSKY PRODUCTS INC.
916400-102

DESIGN ENGINEERING
V. C. SUMMER NUCLEAR STATION JENKINSVILLE, S.C.

NO.	DATE	BY	REVISION	CKD. BY	APPROVAL
4	10/8/99	JMR	REVISED PER CGSS-99-0518	MGR	DKW

MADE	CHECKED	APPROVAL
JMR	MGR	DKW

1MS-33-009 4

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	1	2	3	4	5	6
1	DG LOW LUBE OIL PRESSURE	DG OVERSPEED TRIP	DG FUEL OIL STORAGE TANK LOW/LOW LEVEL	DG FUEL OIL DAY TANK LOW/LOW LEVEL	NOTE 5	DG ENGINE FAILED START
2	DG NOT READY FOR AUTO START (NOTE 1)	DG AUX NOT IN AUTO POSITION	DG FUEL OIL STORAGE TANK HI/LOW LEVEL	DG FUEL OIL DAY TANK LOW LEVEL	NOTE 5	DG ENGINE RUNNING TROUBLE (NOTE 2)
3	DG STARTING AIR LOW PRESSURE	DG MANUAL VLVS NOT ALIGNED PROPERLY	DG FUEL OIL LOW PRESSURE	DG LOSS OF DC POWER	NOTE 5	DG ENGINE TEMPERATURE TROUBLE (NOTE 3)
4	SPARE	DG DIFF LOCKOUT ENERGIZED	DG GENERATOR TROUBLE (NOTE 4)	NOTE 5	NOTE 5	NOTE 5
5	NOTE 5	DG ENGINE TROUBLE SHUTDOWN	DG SELECT SWITCH IN MAINTENANCE	NOTE 5	SPARE	NOTE 5
6	NOTE 5	DG BARRING DEVICE ENGAGED	DG ANNUNCIATOR GROUND/POWER FAILURE	NOTE 5	NOTE 5	NOTE 5

(SHOWN TYPICAL FOR BOTH ANNUNCIATOR STATIONS XCP0636 & XCP0637.)

NOTE 1 - INCLUDES:

A) STARTING AIR LOW PRESSURE; B) DIFFERENTIAL LOCKOUT ENERGIZED; C) LOW LUBE OIL PRESSURE; D) BARRING DEVICE ENGAGED; E) DIESEL GENERATOR AUXILIARIES NOT IN AUTO POSITION; F) MANUAL VALVES NOT ALIGNED PROPERLY; G) SELECTOR SWITCH 43 IN MAINTENANCE; H) LOSS OF DC POWER; I) ENGINE TROUBLE SHUTDOWN; J) START FAILURE RELAY; K) EXCITER NOT RESET.

NOTE 2 INCLUDES:

A) LOW COOLANT PRESSURE; B) FUEL OIL PUMP RUNNING; C) WATER IN AIR TANKS; D) HIGH AFTER COOLING TEMPERATURE; E) CRANKCASE PRESSURE HIGH; F) ROCKER ARM LUBE OIL LEVEL HIGH; G) ROCKER ARM LUBE OIL PRESSURE LOW; H) LUBE OIL LEVEL LOW; I) COOLANT SYSTEM LEVEL LOW; J) FUEL OIL DAY TANK LEVEL HIGH; K) AIR INTAKE DIFFERENTIAL PRESSURE HIGH.

NOTE 3 INCLUDES:

A) LUBE OIL TEMPERATURE LOW; B) COOLING SYSTEM TEMPERATURE LOW; C) LUBE OIL TEMPERATURE HIGH; D) COOLING SYSTEM TEMPERATURE HIGH

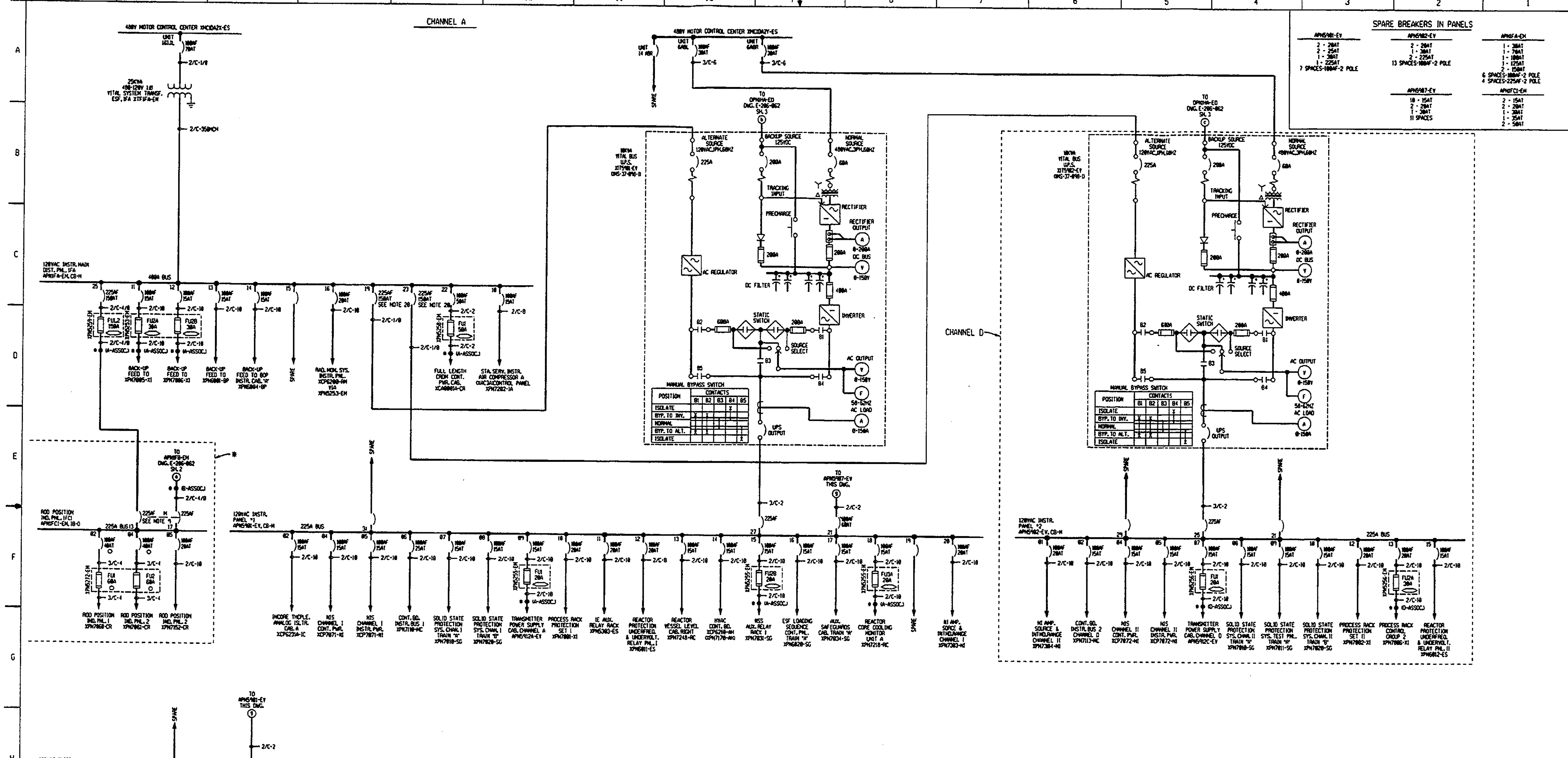
NOTE 4 INCLUDES:

A) OVERVOLTAGE; B) OVERCURRENT 51VDG; C) REVERSE POWER 67DG; D) GEN. STATOR HIGH TEMPERATURE; E) NEG. PHASE SEQUENCE 46DG; F) FIELD GROUND 64DG; G) FIELD FAILURE 40DG; H) SYSTEM GROUND 51DG.

NOTE 5 - ALARMS ASSOCIATED WITH OTHER SYSTEMS

SOUTH CAROLINA ELECTRIC & GAS CO.
VIRGIL C. SUMMER NUCLEAR STATION

MAIN CONTROL BOARD
ANNUNCIATOR STATION
B-804-636 SH.1 & 637 SH. 1
REV. 9
Figure 8.3-0m



NOTES:

1. △ - BREAKERS WITH AUXILIARY CONTACTS FOR INDICATION IN CONTROL ROOM.
2. M - MECHANICALLY INTERLOCKED BREAKERS. 225AF BREAKERS SHOWN WITHOUT TRIP SETTINGS ARE WITHOUT TRIP ELEMENTS.
3. INSTRUMENTS SHOWN ARE LOCATED OR MOUNTED ON ASSOCIATED EQUIPMENT UNLESS OTHERWISE NOTED.
4. ● - INDICATES ITEMS OR AREAS THAT ARE NOT NUCLEAR SAFETY RELATED (NNS).
5. ACB BREAKER RATINGS SHOWN ARE COIL RATINGS WITH 600AF.
6. AVAILABLE SHORT CIRCUIT CURRENT AT BUS 1HA OR 1HB IS 20,600A AT 125VDC.
7. MECHANICALLY INTERLOCKED BREAKERS ARE FOR USE AS DISCONNECT ONLY AND WILL NOT BE USED FOR PROTECTION COORDINATION.
8. THE BREAKERS ARE INTERLOCKED TO ALLOW ONLY THE TWO BREAKERS ASSOCIATED WITH CHANNEL "A" OR THE TWO BREAKERS ASSOCIATED WITH CHANNEL "B" TO CLOSE AT ONE TIME.
9. THE BREAKERS ARE MECHANICALLY INTERLOCKED TO ALLOW ONLY ONE BREAKER CLOSED AT A TIME.
10. ◇ - INDICATES METERING IN THE ESF POWER SYSTEM WHICH IS "NNS". CIRCUITS TO THIS METERING, FROM THE NEAREST PROTECTIVE DEVICE, WILL BE RUN AS ASSOCIATED (XA, XB, OR XC).
11. ⬭ - ISOLATION DEVICE, CLASS 1E TO NON-CLASS 1E.
12. ○ - REACTOR BUILDING PENETRATION PROTECTION DEVICE.
13. USE BUSSMAN LIMITRON OR GOULD-CHASE SHAWMUT FORM 600 FUSES FOR CLASS 1E ISOLATION FUSES AND PENETRATION PROTECTION FUSES ON ALL PANELS, EXCEPT FOR FEEDS FROM PANELS APN5901, 2, 3, 4, 7, AND 8 WHICH REQUIRE GOULD-CHASE SHAWMUT FORM 101 FUSES.
14. BREAKER TO BE SET AT "HIGH" TRIP.
15. DELETED
16. DELETED
17. DELETED
18. PANELS REQUIRE HIGH INTERRUPTING TYPE "FH" BREAKERS.
19. AF = AMP. FRAME
AT = AMP. TRIP
20. BREAKER TO BE SET AT "HIGH" TRIP.

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DECEMBER 2000

THIS IS A NUCLEAR SAFETY RELATED DOCUMENT. NO DEVIATION SHALL BE INITIATED OR PERFORMED WITHOUT PRIOR DOCUMENTATION AND WRITTEN APPROVAL

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SCE&G CAD ENHANCED

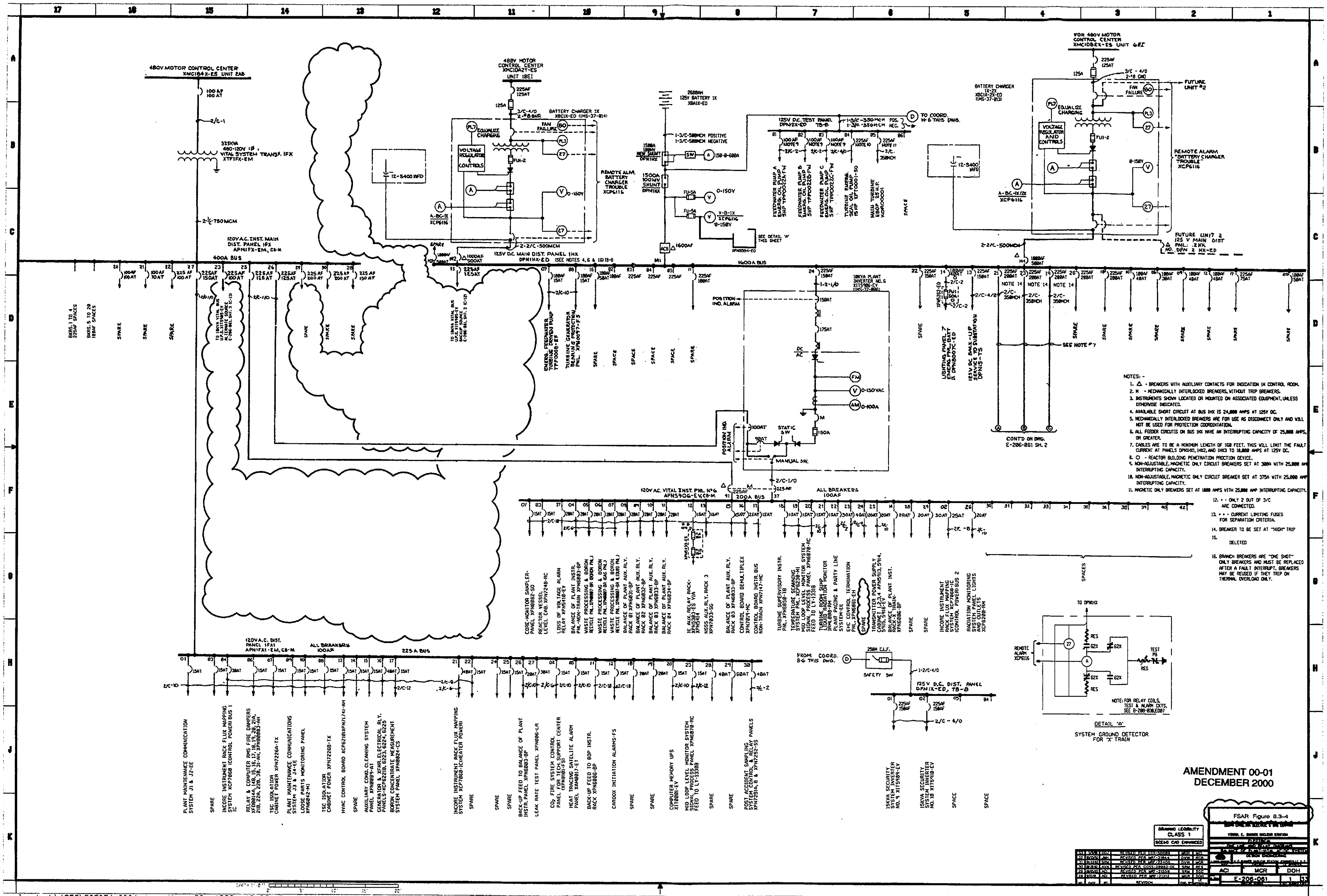
FSAR Figure 8.3-1

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
GILBERT ASSOCIATES, INC.
ELEC. ONE LINE AND RELAY DIAGRAM
ENGINEERED SAFETY FEATURES VITAL AC SYS.
DESIGN ENGINEERING

NO.	DATE	BY	REVISION	CHK. BY	APPROVAL
38	[illegible]	[illegible]	REVISED PER COSS-98-0132	[illegible]	JEO
37	[illegible]	JMH	REVISED PER MRF-21944	DVW	RCB

JMH | DVW | RCB

E-206-062 | 1 | 38


480V MOTOR CONTROL CENTER
480V MOTOR CONTROL CENTER XMC10A2Y-ES UNIT 1BE1
FOR 480V MOTOR CONTROL CENTER
120V A.C. INST. MAIN DIST. PANEL 1FX
125V D.C. MAIN DIST. PANEL 1HX DPN1HX-ED (SEE NOTES 4, 6 & 10 TO 8)
125V D.C. TEST PANEL
120V AC. VITAL INST. PNL. N°6
120V A.C. DIST. PANEL 1FA1
125V D.C. DIST. PANEL
400A BUS
1600A BUS
200A BUS
225 A BUS
ALL BREAKERS 100AF
REMOTE ALARM "BATTERY CHARGER TROUBLE" XCP6116
FUTURE UNIT 2 125 V MAIN DIST PNL. 2HX
CONT'D ON DWG. E-206-061 SH. 2
SEE NOTE 7
POSITION IND. ALARM
MANUAL SW.
STATIC SW
FROM COORD. B-6 THIS DWG.
TO COORD. H-6 THIS DWG.
SAFETY SW
SPARE
SPACE
SPACES
NOTES: -
1. △ - BREAKERS WITH AUXILIARY CONTACTS FOR INDICATION IN CONTROL ROOM.
2. M - MECHANICALLY INTERLOCKED BREAKERS, WITHOUT TRIP BREAKERS.
3. INSTRUMENTS SHOWN LOCATED OR MOUNTED ON ASSOCIATED EQUIPMENT, UNLESS OTHERWISE INDICATED.
4. AVAILABLE SHORT CIRCUIT AT BUS 1HX IS 24,000 AMPS AT 125V DC.
5. MECHANICALLY INTERLOCKED BREAKERS ARE FOR USE AS DISCONNECT ONLY AND WILL NOT BE USED FOR PROTECTION COORDINATION.
6. ALL FEEDER CIRCUITS ON BUS 1HX HAVE AN INTERRUPTING CAPACITY OF 25,000 AMPS, OR GREATER.
7. CABLES ARE TO BE A MINIMUM LENGTH OF 160 FEET. THIS WILL LIMIT THE FAULT CURRENT AT PANELS DPN1H1, 1HX2, AND 1HX3 TO 10,000 AMPS AT 125V DC.
8. ○ - REACTOR BUILDING PENETRATION PROTECTION DEVICE.
9. NON-ADJUSTABLE, MAGNETIC ONLY CIRCUIT BREAKERS SET AT 300A WITH 25,000 AMP INTERRUPTING CAPACITY.
10. NON-ADJUSTABLE, MAGNETIC ONLY CIRCUIT BREAKER SET AT 375A WITH 25,000 AMP INTERRUPTING CAPACITY.
11. MAGNETIC ONLY BREAKERS SET AT 1000 AMPS WITH 25,000 AMP INTERRUPTING CAPACITY.
12. * - ONLY 2 OUT OF 3/C ARE CONNECTED.
13. * * - CURRENT LIMITING FUSES FOR SEPARATION CRITERIA.
14. BREAKER TO BE SET AT "HIGH" TRIP
15. DELETED
16. BRANCH BREAKERS ARE "ONE SHOT" ONLY BREAKERS AND MUST BE REPLACED AFTER A FAULT INTERRUPT. BREAKERS MAY BE REUSED IF THEY TRIP ON THERMAL OVERLOAD ONLY.
DETAIL 'A'
SYSTEM GROUND DETECTOR FOR 'X' TRAIN
NOTE: FOR RELAY COILS, TEST & ALARM CKTS, SEE 6-208-038,E087
AMENDMENT 00-01
DECEMBER 2000
FSAR Figure 8.3-4
DRAWING LEGIBILITY CLASS 1
E-206-061
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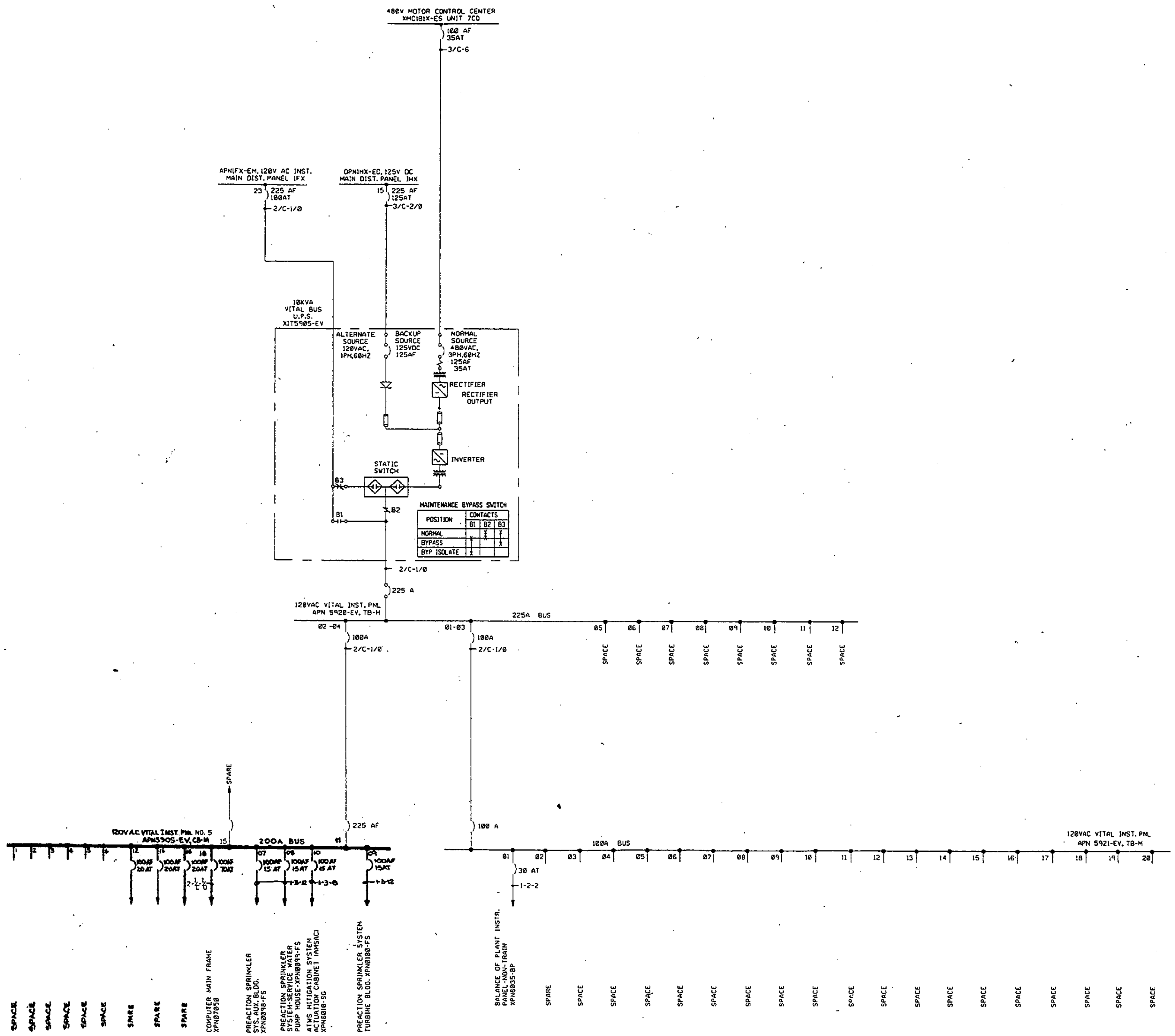

AMENDMENT 00-01
DECEMBER 2000

DRAWING LEGIBILITY CLASS 1
SCE&G CAD ENHANCED

FSAR Figure 8.3-4b

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
ELECTRICAL
ONE LINE AND RELAY DIAGRAMS
BALANCE OF PLANT-VITAL AC-DC SYSTEM
DESIGN ENGINEERING

NO	DATE	BY	REVISION	CHK. BY	APPROVAL
3	5/99	DDJ	ISSUED PER CCR-50089	MGR	MCL

D.D.J. | M.G.R. | T.L.W.

E-206-061 | 3 | 0

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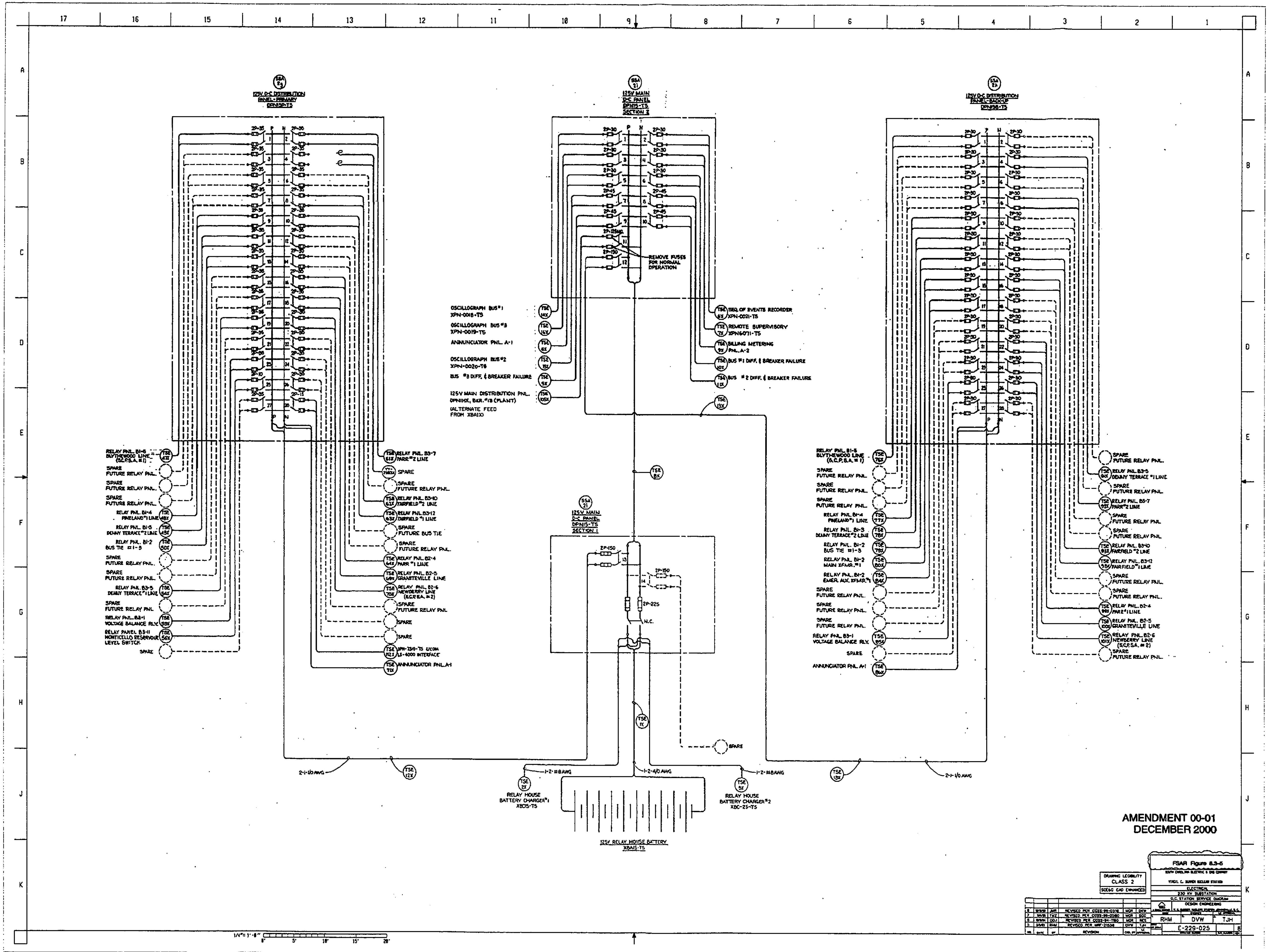

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8.4 STATION BLACKOUT

V. C. Summer Nuclear Station Unit No. 1 conforms to 10CFR50.63 entitled "Loss of All Alternating Current Power" (Station Blackout). V. C. Summer's program meets the guidance provided by Regulatory Guide (RG) 1.155, Station Blackout; Nuclear Management and Resources Council, Inc (NUMARC) 87-00, Guidelines and Technical Bases for NUMARC Initiatives addressing Station Blackout at Light Water Reactors; and NUMARC 87-00 Supplemental Questions/Answers and Major Assumptions dated December 27, 1989. Virgil C. Summer Technical Report TR08200-003 entitled "Compliance to NRC Rule 10CFR50.63" (Station Blackout), documents VCSNS compliance. Additional details are provided in the NRC issued Safety Evaluations References 1 and 2.

8.4.1 STATION BLACKOUT DURATION

NUMARC 87-00 was used to determine an SBO duration of four hours.

The following plant factors were identified in determining the proposed Station Blackout duration:

1. AC Power Design Characteristic Group is P1 based on: 00-01

   a. Independence of offsite power classification of Group "1 1/2"

   b. Severe weather (SW) classification of Group "1"

   c. An extreme severe weather (ESW) classification of Group "3"

2. The emergency AC power configuration group is C based on:

   a. There are two EDGs credited as AC power supplies

   b. One emergency AC power supply is necessary to operate safe shutdown equipment following a loss of offsite power.

3. The target EDG reliability is 0.95.

   a. A target EDG reliability of 0.95 was based on the Virgil C. Summer Station having an average EDG greater than 0.95 over the last 100 demands.

   b. EDG failure statistics for the last 20 and 50 demands, in accordance with the requirements of RG 1.155 was provided, which confirms that the target selection is appropriate.

8.4.2 Coping Method

The V. C. Summer Nuclear Station coping method is in accordance with the "AC-Independent Approach" delineated in NUMARC 87-00 for the required coping duration of four hours and recovery therefrom. In this approach for VCSNS, DC power is required to be available for the coping duration to operate equipment necessary to achieve safe shutdown conditions until offsite or emergency AC power is restored. The following plant systems and components are required to have the availability, adequacy, and capability to achieve and maintain a safe shutdown and to recover from an SBO for a four-hour coping duration.

8.4.2.1 Class 1E Battery Capacity

The V. C. Summer Nuclear Station has sufficient battery capacity and size to support decay heat removal during a Station Blackout for the required four-hour coping duration in accordance with NUMARC 87-00 without load stripping, as discussed in Section 8.3.2.1.2. The battery analysis is documented/maintained in SCE&G Calculation DC08320-005.

8.4.2.2 Condensate Inventory For Decay Heat Removal

00-01

The V. C. Summer plant has adequate condensate inventory for decay heat removal during a Station Blackout for a required duration of four hours. The necessary condensate inventory is assessed by a bounding analysis based on the NUMARC 87-00 Equation. The minimum permissible condensate storage tank level per technical specification requirements provides 172,700 gallons, which exceeds the required quantity for coping with a four-hour Station Blackout per SCE&G Technical Report TR08200-003.

8.4.2.3 Compressed Air

The V. C. Summer air operated valves required for decay heat removal have been evaluated and accepted for manual operation under Station Blackout conditions for the four-hour duration.

8.4.2.4 Effects of Loss of Ventilation

The effects of loss of ventilation within areas of the plant containing equipment necessary to achieve and maintain safe shutdown during a Station Blackout is evaluated per NUMARC 87-00. The dominant areas of concern (DACs) and analysis are documented in SCE&G Technical Report TR08200-003.

8.4.2.5 Containment Isolation

Containment isolation valves that must be operated under SBO conditions must have the ability to be positioned, with indication, independent of the preferred and Class 1E AC power supplies and that no modifications or procedure changes are necessary to ensure containment integrity can be obtained if it is needed under SBO conditions. Containment isolation valve design and operation at VCSNS meet the intent of the guidance described in RG 1.155.

8.4.2.6 Reactor Coolant Inventory

The ability to maintain adequate reactor coolant system (RCS) inventory to ensure that the core is cooled has been assessed for four hours. The generic analysis listed in NUMARC 87-00 was used in this assessment. The expected rates of RCS inventory loss under SBO conditions do not result in core uncovery. 00-01

8.4.3 References

1. USNRC Letter to SCE&G dated January 30, 1992, Subject: Safety Evaluation Regarding Station Blackout Analysis, Virgil C. Summer Nuclear Station, Unit No. 1 (TAC No. M68610).

2. USNRC Letter to SCE&G dated June 1, 1992, Subject: Supplemental Safety Evaluation Regarding Station Blackout, Virgil C. Summer Nuclear Station, Unit No. 1 (TAC No. M68610).

3. U. S. Nuclear Commission Regulatory Guide 1.155, "Station Blackout".

4. NUMARC 87-00, Nuclear Management and Resources Council, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors".

APPENDIX 8A

ADDITIONAL CABLE AND TRAY DESIGN CONSIDERATIONS

8A.1 METHODS EMPLOYED

Sections 8A.1.1 through 8A.1.3 describe methods employed to show sufficient conservatism in the cable and tray design to assure that adequate cable tray hanger strength exists, that cables are sufficiently sized, and that the weight of upper cables in trays does not damage bottom layer cables.

8A.1.1 WEIGHT ON HANGER

Cables are routed in tray in two different configurations (e.g., single lay and random lay). The weight of the cables, tray, tray covers, fire barrier materials on the tray, and any conduits and pipes hung from the tray supports were used to establish the tray support cap ability. The allowable cable weight limit is based on the capability of the cable tray (e.g., 35 lbs/ft^2 of tray bottom area for single lay 4" deep trays and 45 lbs/ft^2 of tray bottom area for random lay 6" deep trays).

For single lay cable tray, percent fill and cable heating were not the deciding factors for limiting tray fill. Engineering determined that the maximum number of cables that a single lay tray can accommodate is based on the cable diameters versus the width of the tray.

The initial design criteria for random lay tray was based on a maximum of 50% fill. 00-01
Engineering performed calculations to ensure that cable heating and cable weight were acceptable whenever the tray fill was less than 50%. Because the tray fill was conservatively calculated based on the square of the cable diameter in lieu of the cross sectional area of the cable, the actual tray fill is less than the calculated tray fill. The cable management system computer program was used to monitor tray fill. The 50% limit originally established was found to be inadequate as cables were added over the life of the plant. Therefore, calculations were performed whenever a random lay cable tray fill exceeded 50%. Subsequently the criteria for random lay power cable trays was changed to weight per tray support with an alarm point of either 50% fill for trays presently less than 50% filled or the last calculated allowable % fill for trays whose fill exceeded 50%. In addition, the criteria and alarm point for instrument and control tray were changed to weight only per tray support only, since heat loading was not a concern.

Whenever a power cable is added to a random lay power tray and the associated tray fill exceeds the previously accepted percent tray fill limit, a calculation is performed. The calculation addresses additional loading from the new power cables to ensure that the combined weight of the new and existing cables is less than the allowable design weight capability of the tray support. Heat loading is also evaluated to ensure that the existing ampacity derating factors are still applicable.

Engineering determined that cable heating was not a concern for the small currents and intermittent operating conditions associated with control and instrument cables and therefore only total cable weight needed to be considered. The design limit for control and instrumentation cable tray fill is based on verifying that the weight of the new and existing cable does not exceed the tray and tray support weight capability. The cable tray fill criteria for control and instrument trays is controlled by the cable management system computer program. This program contains an alarm limit for the maximum weight allowed for each tray size used. Therefore, manual calculations to monitor cable weight are not required because this calculation is performed by the cable management system and an alarm is provided if the tray or tray support weight capability is exceeded. 00-01

8A.1.2 CABLE HEATING

Single layer kV and 480 volt cable trays need not be considered with respect to possible cable overheating since, inherently, the fill is limited to the single layer of cable with appropriate derating factors applied. Rated ampacities are in accordance with ICEA P-46-426[1]; the free air ratings for the applicable ambient temperatures were derated 00-01 for the presence of adjacent power cables. In addition, a load factor of 100 percent was assumed and feeders are sized for 110, 125, or 140 percent of rated current, depending 00-01 upon type of service (resistive loads; motors, power panels and small transformers; and large power transformers, respectively).

No ampacity derating factors are applied to control and instrument cables due to the type of service and low current levels.

For random lay power trays (Reference 2, Table 12), a 3 inch depth was used to determine cable ampacity. Therefore, derating due to tray fill need only be considered for trays with fill greater than 50 percent design objective, since the 50 percent design fill is equivalent to a 3 inch depth. The 100 percent load factor feeder sizing considerations previously noted were also applied, along with appropriate derating where required for higher ambient temperatures.

In selected cases fill above 50% was authorized to larger values after specific evaluation of heat dissipation and weight loading. Heat dissipation was evaluated using the methods described in Reference 3.

From Figure 4 if Reference 3 the following linear approximation can be made for the allowable heat generation versus tray fill:

$$Q_d = \frac{6.5}{d^{1.47}} \qquad (1)$$

Where:

Q_d = Allowable heat generation per unit area of cable cross-section to limit conductor temperature to 90°C

d = Depth of tray fill in inches

Since heat generation in a given cable at a fixed temperature is proportional to the square of the current, the following relationships can be established:

$$Q_d = KI_d^2 \qquad (2)$$

Where:

I_d = Ampacity of cable for tray fill depth d

K = Constant

Combining into equation (1) and developing a ratio: 00-01

$$\frac{Q_{d'}}{Q_d} = \frac{KI_{d'}^2}{KI_d^2} = \frac{(d)^{1.47}}{(d')^{1.47}}$$

Using the relationship, the curve of Figure 4 in Reference 3 was extended to cover larger fills of six inch deep tray. Because Reference 3 was developed for three inch deep tray, the tray fill permitted is one-half the value shown in Figure 4. As long as the tray fill meets this criterion, the cable ampacities of Reference 2 are still permissible.

There is an additional margin of conservatism in the heat dissipation calculation. Tray fill is calculated using diameter squared to represent cable cross-sectional area instead of actual cable area. This represents a margin of 27.3 percent above actual tray fill. In addition, non-continuous current carrying cables are not included in heat density calculations but are included in tray fill and weight calculations, which ensures conservatism.

No ampacity derating of cables has been necessary because of heat dissipation.

8A.1.3 CABLE SIDE WALL PRESSURE

In accordance with manufacture's published information the maximum allowable side wall pressure of typical cables used is considerably higher than the pressure that cables on the bottom of a tray will experience from cables above, even for fills in excess of 50 percent. The minimum allowable side wall pressure is 50 lb/ft, while the maximum loading per cable in a tray filled to the tray support limit, or 100% physical fill, will be less than 7 lb/ft [18]. 00-01 00-01

8A.2 CONCLUSIONS

Tray fill is monitored by computer. Any tray that exceeds the design fill is reported on a separate printout. This printout is used in routing design, and cables are routed through other, less full trays. Late in construction other trays may exceed the maximum values justified in Sections 8A.1.1 through 8A.1.3. When this occurs, the situation will be evaluated and action will be taken to relieve such a condition. Alternatives are to calculate the actual tray load and verify that the load does not exceed the design capacity, enlarge the existing tray, strengthen the existing hangers, or in the case of random lay power trays where the concern is ampacity, each individual circuit application can be evaluated and the total ampacity calculated.

8A.3 REFERENCES

1. Insulated Cable Engineers Association, "Power Cable Ampacities," ICEA P-46-426-1962.

2. Insulated Cable Engineers Association, "Ampacities of Cables in Open-Top Cable Trays," ICEA P-54-440.

3. Stolpe, J. "Ampacities for Cables in Randomly Filled Trays," Institute of Electrical and Electronics Engineers Transaction Paper 70TP557PWR. 00-01

NOTE Appendix 8B Appendix 8B is being retained for historical purposes only.

99-01

APPENDIX 8B

CABLE RACEWAY FIRE BARRIERS DESIGN

8B.1 PURPOSE

This report describes the criteria, assumptions and design used by Gilbert Associates, Inc. (GAI) to locate and construct cable raceway fire barriers on the Virgil C. Summer Nuclear Station for the South Carolina Electric and Gas Company.

8B.2 CRITERIA

Fire barriers were designed to comply with IEEE Standard 384-1977 "Criteria for Independence of Class 1E Equipment and Circuits."

Fire barriers are required to prevent propagation of a fire between two, or more, raceways of redundant divisions or non-class 1E to Class 1E cable trays which do not maintain minimum physical separation. This minimum physical separation is specified in IEEE-384, and in GAI - "Construction Guideline for Electrical Circuit Physical Separation" (GAI Drawing Number S-200-926). In summary, the minimum separation distances are based on open ventilated cable trays and are as follows:

1. Cable spreading area - one foot horizontally and three feet vertically.

2. General plant area - three feet horizontally and five feet vertically.

Where the above separation is not provided the following specified criteria extracted from IEEE-384 are used:

1. The use of physical barriers or enclosed raceways, which qualify as barriers, shall be separated by a minimum distance of one inch.

2. Vertical barriers, separating redundant horizontal tray running parallel requiring horizontal separation will have a minimum of one foot (or to ceiling) extension above the top of the tray at the highest elevation in a stack.

3. Horizontal barriers, separating redundant horizontal trays crossing requiring vertical separation will have a minimum of three feet extension beyond each side of the widest tray (one foot in the cable spreading area).

4. Horizontal barriers, separating redundant horizontal trays running parallel requiring vertical separation will have a minimum of six inches extension beyond each side of the widest tray. 00-01

These barriers are intended to prevent redundant raceway-to raceway fires which are self-initiated only.

Based on the above, the following was extrapolated:

1. Solid tray covers and bottoms, referred to in this report as fire shields, may be added to open ladder tray to quality it as an enclosed raceway. Trays containing power cables (480 volt and higher) may require barriers in lieu of fire shields since fire shields may inhibit ventilation.

2. Channel tray (4 inch open top, solid bottom) will be considered an enclosed, open top tray and may require covers only.

3. Instrument trays, in this plant are installed with solid covers and bottoms and constitute an enclosed raceway.

4. Conduit alone constitutes an enclosed raceway.

5. Conduit installed beneath or alongside of an open tray of a redundant division does not require a barrier.

6. Conduit installed less than five feet (three feet in a cable spreading area) above a tray of a redundant division requires a barrier.

7. Conduits may be wrapped with a flexible fireproof material which will suffice as a barrier. This may be used where space permits installation.

8B.3 MATERIALS AND INSTALLATION

8B.3.1 FIRE SHIELDS

Tray covers and bottoms will be made of 18 gauge steel. They will be attached to the tray by one of several methods described in detail by the tray vendor for other applications in the plant. Basically, the covers are strapped or clamped to the tray. Covers will be peaked to 1 inch, except for covers for fittings which will be flat; bottoms will be flat.

8B.3.2 BARRIERS

Board barriers will be made from Babcock and Wilcox M-Board in one inch thickness. Installation techniques are under development.

8B.3.3 CONDUIT WRAPPING

Conduit wrapping will be done with Johns-Manville Cerablanket, or Babcock and Wilcox Kaowool blanket materials. These are high-temperature fiber blankets in a thickness of one inch and, typically, a width of 24 inches. The blanket will be wrapped around the conduit and fastened with fire resistant tape or by other similar method.

8B.4 ACTUAL CASES

Detailed in Figures 8B-1 through 8B-12 are representatives cases found in the Virgil C. Summer Nuclear Station where physical separation of redundant channels could not be maintained. The type of fire barrier designed for each case and the installation methods are described below. Options are provided for each case and an option may be selected, for individual cases, based on economics, available space and complexity (e.g., it may be more advantageous to use one board barrier rather than many covers and bottoms where several trays are involved).

1. Detail 1 - Redundant Horizontal Trays Crossing, Requiring Vertical separation

    a. Option A - shows the use of fire shields on each tray.

    b. Option B - shows the use of a horizontal board barrier.

2. Detail 2 - Redundant Horizontal Trays Running Parallel Requiring Vertical Separation

    a. Option A - shows the use of fire shields on each tray.

    b. Option B - shows the use of a horizontal board barrier

3. Detail 3 - Redundant Horizontal Trays Running Parallel Requiring Horizontal Separation

    a. Option A - shows the use of fire shields on each tray.

    b. Option B - shows the use of a vertical board barrier.

4. Detail 4 - Horizontal Tray Crossing Redundant Vertical Tray Requiring Horizontal Separation

    a. Option A - shows the use of a fire shield on each tray.

    b. Option B - shows the use of a vertical board barrier.

5. Detail 5 - Horizontal Conduit Crossing Over Redundant Horizontal Tray Requiring Vertical Separation

    a. Option A - shows the use of a fire shield on each tray.

    b. Option B - shows the wrapping of conduit.

    c. Option C - shows the use of a horizontal board barrier

6. Detail 6 - Horizontal Conduit Above Redundant Horizontal Tray Running Parallel Requiring Vertical Separation.

    a. Option A - shows the use of a fire shield on each tray.

    b. Option B - shows wrapping of the conduit

    c. Option C - shows the use of a horizontal board barrier.

7. Detail 7 - Vertical Conduit Crossing Redundant Horizontal Tray Requiring Horizontal Separation

    a. Option A - shows the use of a fire shield on each tray.

    b. Option B - shows wrapping of the conduit.

    c. Option C - shows the use of a vertical board barrier.

8. Detail 8 - Horizontal Conduit Crossing redundant Vertical Tray Requiring Horizontal Separation

    a. Option A - shows the use of a fire shield on each tray

    b. Option B - shows wrapping of the conduit.

    c. Option C shows the use of a vertical board barrier.

APPENDIX 8C

SUMMARY OF ANALYSIS OF SEPARATION BETWEEN TRAY FOR NON-CLASS 1E CIRCUITS AND TRAY FOR CLASS 1E CIRCUITS

8C.1 OBJECTIVE

Perform an analysis in accordance with IEEE 384-1974, Section 5.1.1.2, to ensure acceptable separation between trays for non-class 1E circuits and trays for Class 1E circuits.

8C.2 CRITERIA

Separation shall be sufficient that no single electrically initiated fire can result in the loss of a safety system function. | 00-01

8C.3 BASIS

The Fire Protection Research Program tests performed at Sandia Laboratories for the U.S. Nuclear Regulatory Commission (NRC) were used as a source of data on the characteristics of cable fires. The following conclusions drawn from the reports were used in the analysis of individual situations:

1. It is difficult to initiate a fire from an electrical fault or overload in trays with cables which satisfy the flame retardant criteria of IEEE 384-1974.

2. If a fire can be started and propagated, it spreads through a stack of trays with an angle of spread of approximately 35 degrees from vertical.

3. In horizontal trays, the fire does not propagate horizontally within a given tray.

4. Fire does not propagate downward from one tray to the tray below.

The results of the IEEE 383 flammability tests for cable actually used at Virgil C. Summer Nuclear Station were also used to determine that the flammability of the cable used at Virgil C. Summer Nuclear Station is less than that used for the full scale tests at Sandia Laboratories. | 00-01

8C.4 METHOD

The tray drawings for plant areas containing trays for Class 1E circuits are reviewed and each case where a tray for non-Class 1E circuits approaches a tray for Class 1E circuits is noted and given an identification number. Each case is then clarified with sections and details as necessary to determine separation distances and to categorize the situation. The cases are then individually reviewed using the basis given above to determine the adequacy of the separation. If the criteria stated above are not satisfied by the existing design, suitable barriers are added to the raceway system design so that the final design satisfies the criteria.

1. Tray for non-Class 1E circuits parallel to tray for Class 1E circuits. Subcategories include: above, below, and between.

2. Tray for non-Class 1E circuits crossing tray for Class 1E circuits. Subcategories include: above, below, and between.

3. Tray for non-Class 1E circuits bridging between routes of trays for redundant Class 1E circuits. Subcategories include: above, below, and between.

4. Trays for non-Class 1E circuits diagonally parallel trays for Class 1E circuits. Subcategories include: above and below.

5. Trays for non-Class 1E circuits vertical. Subcategories include: parallel to or crossing tray for class 1E circuits.

8C.5 ANALYSIS

A listing of cases analyzed is provided by Section 8C.6. In addition, detailed analyses for three typical cases are presented in Sections 8C.5.1 through 8C.5.3.

8C.5.1 CASE NO. 041-C

8C.5.1.1 Description

1. Location

   Control Building, Elevation 425'-0

2. Figure

   Figure 8C-1

3. Type of Area

   Cable spreading room

4. General Description

   A tray for non-Class 1E (channel X) control circuits passes over a vertical stack of trays for Class 1E, channel A circuits and further north passes over a vertical stack of trays for Class 1E, channel B circuits.

5. Category

   Bridging - above

6. Types of Trays

   All trays shown in Figure 8C-1 are open ventilated ladder type, except tray 5144 (A) which is the totally metal enclosed type.

7. Number of Circuits

   Tray 4290 (x) - 316 control circuits

   Tray 4351 (x) - 103 control circuits

   Tray 4650 (x) - 38 control circuits

   Tray 4314 (A) - 337 control circuits

   Tray 4284 (A) - 182 control circuits

   Tray 5144 (A) - 124 instrument circuits

   Tray 4326 (B) - 435 control circuits

   Tray 4325 (B) - 209 control circuits

8. Significant Circuits

   Both the channel A and B trays contain a number of circuits for the component cooling water, emergency feedwater, safety injection, and service water systems; as well as circuits for other safety systems.

8C.5.1.2 Analysis

All circuits are for control or instrumentation and have very low internal energy levels. Therefore, energy is not available to initiate a fire.

Any fire which might start in the trays for non-class 1E circuits will not propagate to either of the stacks of trays for the Class 1E circuits since tests have demonstrated that cable fires do not propagate downward. In addition, the tests have shown that a cable fire will not propagate horizontally over the 5 foot-8 inch distance between the stacks of trays for the Class 1E circuits.

A fire which might start in the trays for the Class 1E circuits could propagate to trays for the non-Class 1E circuits but, as stated above, tests have shown that the fire would not propagate horizontally to the trays for the redundant Class 1E circuits nor would the fire propagate downward to the other stack. 00-01

Although the preceding analysis documents that a fire barrier is not required, a barrier was installed in the Channel B control trays in compliance with the licensing commitment to provide barriers for multiple separation violations as describe in paragraph 8.3.1.4.1, Item 4. 00-01

8C.5.2 CASE NO. 102-A

8C.5.2.1 Description

1. Location

   Reactor Building Elevation, 436'-0"

2. Figure

   Figure 8C-2

3. Type of Area

   General plant area

4. General Description

   Trays for Class 1E circuits, channels A and D, run parallel to trays for non-Class 1E (channel X) circuits throughout this elevation of the Reactor Building. No trays of other channels are present.

5. Category

   Parallel – beside

6. Types of Trays

   The trays, as shown by Figure 8C-2, consist of both open ventilated ladder trays and totally metal enclosed trays.

7. Number of Circuits

   Tray 3098 (X) - 13 480 volt random layed power circuits

   Tray 4168 (X) - 33 control circuits

   Tray 5063 (X) - 22 instrument circuits

   Tray 4174 (A) - 62 control circuits

   Tray 5069 (A) - 3 instrument circuits

   Tray 5077 (D) - 3 instrument circuits

8. Significant Circuits

   Tray 4174 contains a number of circuits from the chemical and volume control system, reactor coolant system, and safety injection system; as well as from other systems.

8C.5.2.2 Analysis

The Class 1E, channel D circuits are in a totally metal enclosed raceway at the bottom of the stack. Therefore they are adequately separated from other trays.

The lower of the two trays for Class 1E channel A circuits is totally metal enclosed and therefore, is adequately separated. Any fires which might start in the upper of the two trays for Class 1E channel A circuits would not propagate to the tray for the channel D circuits nor to the trays for non-Class 1E circuits. | 00-01

The bottom tray for non-Class 1E circuits is totally metal enclosed and therefore, is adequately separated from other trays.

The middle tray for non-Class 1E circuits contains control circuits which do not have adequate energy to initiate a fire. Should a fire occur, it could propagate to the top tray for the Class 1E, channel A circuits and to the top tray for non-Class 1E circuits. However, this is acceptable because only one channel of Class 1E circuits would be affected and, therefore, system safety functions would be maintained.

The top tray for non-Class 1E circuits contains power circuits which potentially could initiate a fire. However, the tests have shown that such a fire is very unlikely and should such a fire occur, it would not propagate to any other trays in this configuration.

Although the preceding analysis documents that a fire barrier is not required, a barrier was installed in the Channel D control trays in compliance with the licensing commitment to provide barriers for multiple separation violations as describe in paragraph 8.3.1.4.1, Item 4. 00-01

8C.5.3 CASE NO. 073-A

8C.5.3.1 Description

1. Location

   Auxiliary Building Elevation, 338'-0"

2. Figure

   Figure 8C-3

3 Type of Area

   General plant area

4. General Description

   Trays for Class 1E circuits, channels A and B, run parallel to trays for non-Class 1E circuits, channel X. This situation exits for a distance of 20 feet.

5. Category

   Parallel - above and beside

6. Types of Trays

   Both trays for Class 1E circuits contain control circuits. Trays for non-Class 1E circuits include instrument, control, and random layed power circuits.

7. Number of Circuits

   Tray 4062 (A) - 28 control circuits

   Tray 4064 (B) - 27 control circuits

   Tray 5022 (X) - 38 instrument circuits

   Tray 4059 (X) - 106 control circuits

   Tray 3033 (X) - 49 random layed power circuits

8. Significant Circuits

   Both trays 4062 and 4064 contain circuits for the chemical and volume control system and the leak detection system, as well other systems.

8C.5.3.2 Analysis

Tray 4064 for Class 1E, channel B circuits is separated by considerably more than 5 feet vertically and 3 feet horizontally from all other trays and, therefore, is adequately separated.

Tray 4062 for Class 1E, channel A circuits is 14 inches away from tray 5022 for non-Class 1E, channel X circuits. However, tray 5022 is totally metal enclosed and, therefore, is not a hazard to tray 4062. Tray 4062 is more than 5 feet horizontally and 3 feet vertically from all other trays and therefore, is adequately separated.

8C.6 CASES ANALYZED

The following pages list the cases analyzed.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION UNIT #1

ELECTRICAL
TRAY SEPARATION ANALYSIS
CONTROL BUILDING
ABOVE 425'-0"

MADE ROB | CHKD HMS | DRAWING NO. 04 4461 SS-200-941 | SH. NO. 041-1 | REV D

SQ LDR RWP | ENG INTERF | GILBERT ASSOCIATES, INC. ENGINEERS AND CONSULTANTS READING, PA.

SCALE | W O 044461-020 | ENGINEER APPROVAL DEPT. DATE

REV	MADE	CH	SQL	APP	DATE	REV	MADE	CH	SQL	APP	DATE
C	Q4	-	-	E	[illegible]	D	PF				

LEGEND
B = BRIDGING
C = CROSSING
D = DIAGONAL
P = PARALLEL
V = VERTICAL

NOTES:-
1. FIRST 3 DIGITS ARE LAST 3 DIGITS OF CABLE TRAY DRAWING NUMBER; SERIES E-214-XXX.
2. FOR DEFINITION OF CIRCUIT CHANNEL DESIGNATIONS, SEE FSAR TABLE 8.3-4.
3. * - THESE BARRIERS WERE INCLUDED IN ORIGINAL TRAY SYSTEM DESIGN.
4. ◯ INDICATES SPECIAL NOTES - SEE SHEET SN-1.

CASE NUMBER (NOTE 1)	DRAWING COORDINATES	CATEGORY SEE LEGEND	SITUATION (NOTE 2) (LETTERS REPRESENT CHANNEL OF CIRCUITS IN CABLE TRAYS)	VERTICAL DISTANCE	HORIZONTAL DISTANCE	BARRIER REQUIRED (NOTE 3)	REMARKS
041-A	E-11	P	N ABOVE B	2'-7"	-	YES*	
041-B	G-11	P	L ABOVE A	2'-7"	-	YES*	
041-C	F-6	P,C	B BELOW X	12"	-	NO	1 G
041-D	H-7	C	D ABOVE X	12"	-	NO	2
		C	D ABOVE A	2'-7"	-	YES*	
041-E	E-5	P	B ABOVE E	12"	-	NO	E TOTALLY ENCLOSED
		D	B BELOW E	1'-1"	12"	NO	B TOTALLY ENCLOSED
		C	B BELOW E	1'-11"	-	YES*	
041-F	D-3	P	B BELOW X	12"	-	NO	1
041-G	H-8	P	D NEXT TO X	-	6"	NO	1
		P	D ABOVE X	12"	-	NO	2
041-H	H-12	C	B BELOW X	12"	-	NO	1
041-J	E-8	P	E BELOW X	12"	-	NO	1
041-K	C-3	P	B ABOVE X	12"	-	NO	2, (3) G
041-L	E-3	P	B ABOVE E	1'-2"	-	NO	E TOTALLY ENCLOSED
041-M	H-6	P,V	D NEXT TO X	-	6"	NO	2 · D TOTALLY ENCLOSED
041-N	E-10	C	B BELOW X	4'-2"	-	NO	1
041-P	E-9	C	N ABOVE B	2'-7"	-	YES*	

D
D

RELEASED FOR BIDDING PURPOSES CONSTRUCTION
ENGR.
DATE

APPENDIX 8D

ANALYSIS OF THE ACCEPTABLE VOLTAGE RANGE TO BE APPLIED TO THE ESF SYSTEM

8D.1 CRITERIA

This calculation was based on two criteria:

- The voltage at each piece of safety related equipment must be within the safe operating range for that piece of equipment.
- The voltage of the offsite sources must be sufficient to operate the required loads in the event of an accident without actuating the degraded voltage relays.

NOTE 8D.2
This section is being retained for historical purposes only.

00-01

8D.2 METHOD

In preparation for the development of the calculations, a "Feeder/Load Data Base" was developed and verified. This data base contains information on the characteristics of the safety related loads and their feeder circuits, including the demand load for various plant operating conditions. The characteristics for the system equipment and materials, such as transformers and cables, were taken from the "as-built" data for the specific equipment and materials.

The system calculations were performed using the DAPPER program. The first calculation established a base case model of the electrical power distribution system. This model includes the existing transformer tap settings which include a 2.5% boost for the 480 volt unit substation transformers 1DA1, 1DA2, 1DB1, and 1DB2. For unit substations, 1EA1 and 1EB1 and for the emergency auxiliary and safeguards transformers, the taps are set at the nominal position. Throughout the calculation process, the transformer tap settings were reviewed to determine if revised settings could improve the overall performance of the system. (Reference calculation DC-820-001.)

The next calculation modified the base case system model to evaluate the system under the worst case loading conditions. This condition results from the large break LOCA accident during the injection phase. The source voltage in this model was manually reduced and the system was repeatedly analyzed in an iterative process until the worst case motor terminal voltage was reduced to 90% of its rated voltage. The motors in V. C. Summer Station were specified and designed for steady state operation with a terminal voltage in the range of ± 10% of their rated voltage. The voltage at the motor control center (MCC) buses was also checked and found to exceed 420 volts.

This ensures that there is sufficient voltage for the pick-up of the MCC contactors. The resulting system model established that a voltage equal to or greater than 90.2% on 7.2 kV buses 1DA and 1DB is sufficient to ensure adequate voltage at the terminals of the safety related motors. Since the purpose of this part of the evaluation is to determine the minimum 7.2 kV bus voltage to provide adequate terminal voltage for all Class 1E loads, the number of buses connected to the offsite source and the voltage of the offsite source are not significant. The results of this model are summarized in Table 7.3.3 of Calculation DC-820-001. 00-01

With the minimum 7.2 kV bus voltage established, the next effort determined the minimum setpoint for the degraded voltage relays. Since these relays have a tolerance on both their calibration and operation, a detailed evaluation of the total tolerance band was performed. This determined a total tolerance band of ± 0.328%. Since the relay must operate before the 7.2 kV buses reach the minimum acceptable voltage, the setpoint value must exceed the minimum value by an amount at least equal to the tolerance. To provide both a margin and consistency with the previous settings, the setpoint was established at 91.34% of rated voltage. (Reference calculation DC-820-001.)

Based on the degraded voltage relay setting, the tolerance on the relay calibration and operation, and the response of the SCE&G transmission system to a trip of the V. C. Summer Nuclear Station, the next part of the effort determined the minimum acceptable offsite source voltages during normal plant operation.

Studies of the transmission system under extreme loading and system configuration conditions have determined that 230 kV system voltage will dip to 97.2% of the pre-trip voltage in the event of a unit trip. After less than 3 seconds, the system voltage will recover to 98.6% of the pre-trip voltage. Similarly, the 115kV system voltage will dip to 95.7% of the pre-trip voltage in the event of a unit trip and will recover in less than 3 seconds to 96.8% of the pre-trip voltage.

The DAPPER program was used to model the effects of the motor starting conditions in the event of an accident loading sequence on the 115 kV and 230 kV offsite sources. Based on the tolerance band of the relays and the motor inrush conditions, the 7.2 kV bus voltage must be at least 93.9% of rated voltage prior to motor starting to avoid relay actuation (including a 1% margin which was determined to be unnecessary subsequent to the completion of the calculation). The minimum pre-accident voltage is also dependent on the number of plant buses connected to each offsite source. In a further evaluation, the capabilities of the various combinations of safeguard transformers and the voltage regulating transformer were determined and combined with the worst case voltage dip resulting from a unit trip. The results of these evaluations are summarized in Table 8.2-2. (Reference calculation DC-820-00l.)

The final part of the analysis determined the maximum allowable offsite system voltages. Additional system models were developed with the DAPPER program for plant operation in modes 5 or 6, cold shutdown or refueling. One model evaluated the system using the emergency auxiliary transformer, XTF-31, as the source and the second model used the safeguard transformers, XTF-4 and 5, as the source. The loading consisted of the minimum set of equipment that would be expected to be operational during plant shutdown and only one of the two trains of ESF equipment was supplied from each offsite source. The models were repeatedly analyzed with increased source voltages until the worst case motor terminal voltage reach 110% of motor rated voltage. The results of these models are summarized in Table 8D-2, and the maximum voltage limits are included in Table 8.2-2.

8D.3 CONCLUSION

As described above, the 7.2 kV bus voltage must be at least 90.2% of rated voltage to ensure the voltage at motor terminals exceeds the rated minimum motor voltage for steady state operation. This voltage is also sufficient to ensure MCC contactor pick-up. (Reference calculation DC-876-007.)

The setpoint for the degraded voltage relays must be at least 90.528% of rated voltage to ensure that the relays actuate when the 7.2 kV bus voltage reaches the minimum defined above. The actual relay setpoint is 91.34% of rated voltage.

The offsite system voltages must exceed the minimum values listed in Table 8.2-2 (Reference DC-820-001) in order to ensure that the degraded voltage relays will reset 00-01 after the first loading step and will not (inadvertently) drop-out on subsequent steps in the event of an accident. These minimum voltages are dependent on the number of buses connected to each offsite source, the arrangement of transformers, and on whether the voltage regulator is in service.

The voltage of the offsite sources must not exceed 104.2% of rated in order to avoid excessive voltage on motor terminals. The 115 kV line voltage can be higher than this if the voltage regulator is in service.

No improvement in overall system performance can be obtained with alternative transformer tap settings.

TABLE 8D-1 (Deleted per RN 99-087)

Intentionally deleted. (Calculated Minimum Voltage Levels on Motors and Buses provided in Calculation DC-820-001, Table 7.3.3) 00-01

TABLE 8D-2

CALCULATED MOTOR VOLTAGES FOR MAXIMUM OFFSITE VOLTAGE

Two (2) cases, BLLXTF45 (115 kV source) and BLLXTF31 (230 kV source), were created to determine the maximum offsite system voltage allowable without producing excessive voltages at the motor terminals. Since "A" train was chosen as the worst case bus (heaviest load), "B" train was chosen as the bus to study under light load conditions (Mode 6). The criterion for evaluating worst case conditions was a running motor reaching 110% of rated terminal voltage (NEMA standard maximum).

The source used for the evaluation of the 230 kV system was an emergency auxiliary transformer, XTF-31. The source used for the evaluation of the 115 kV system was 2 ESF transformers, XTF-4 and 5, in parallel.

The offsite voltage was decreased by small increments of voltage from 1.0 per unit until the worst case motor was found.

DAPPER BUS #	OPERATING "B" TRAIN MOTORS	MAXIMUM ALLOWABLE VOLTAGE	MAXIMUM OFFSITE VOLTAGE 115kV SOURCE CASE BLLXTF45 120 kV (1.042 pu)	MAXIMUM OFFSITE VOLTAGE 230 kV SOURCE CASE BLLXTF31 240 kV (1.042 pu)
55	XPP1B	7590	7477	7476
72	XPP39B	7590	7472	7471
502	XHX1B	506	506 *	506 *
504	XPP31B	506	504	504
509	MFN97B	506	501	501
601	XPP48B	506	497	497
602	XFN23B	506	495	495
604	XPP32B	506	496	496
5004	ALOP2	506	497	497
5007	XFN36B	506	496	496
5504	XFN46B	506	496	496
5507	XFN133	506	498	498
5509	XFN32B	506	497	497
6002	XPP4B	506	498	498
6003	XPP141B	506	498	498
6004	XFN45B	506	497	497
6006	XPN48	506	497	497
6007	XFN45A	506	497	497
7006	XFN80B	506	494	494
9003	XFN38B	506	498	498
9005	XFN39B	506	499	499
9013	XFN83B	506	498	498

* Worst Case Motor

Reformatted Per
Amendment 00-01

TABLE 8D-3

(Deleted per RN 99-007) 00-01

APPENDIX 8E

ANALYSIS OF THE VOLTAGE DROPS ON THE ESF SYSTEM WHEN STARTING A 6900 OR 460 VOLT MOTOR WITH THE DIESEL GENERATOR AS THE SOURCE

8E.1 CRITERIA

The criteria was to determine (1) the voltage at the terminals of the largest safety related 6900 and 460 volt motors when they are started and (2) the voltage at the other Safety Related buses during the same period. The power source was considered to be the diesel generator with the safety injection signal loads operating on the buses.

8E.2 BACKGROUND

The 6900 volt charging/safety injection (CH/SI) pump motors and the 460 volt service water booster pump (SWBP) motors are the largest safety related motors for their respected voltages. Therefore, their characteristics were used in the calculations.

The DAPPER computer program was used to simulate the restart of the largest motors and to determine the effect on system voltages. The diesel generator can be modeled as "an infinite source" with zero impedance when modeling the system under steady state conditions since the generator voltage regulator will hold the terminal voltage to within ± 1/2% of the setting. However, for transient conditions, the diesel generator model needs to include an internal impedance since the voltage regulator can not respond immediately to changes in loading. The source impedance for the transient model was based on the short circuit impedance of the generator as described below in section 8E.3. To obtain the internal source voltage, the source voltage of the model was manually adjusted to produce a machine terminal voltage of 0.945 per unit (under steady state conditions) with the generator load equal to the maximum system load, minus the load of the motor to be restarted. A terminal voltage of 0.945 per unit was used because the lower administrative limit for setting the voltage regulator is 95% and the regulator has a tolerance of ± 1/2%. To find the voltage levels during the initial 00-01
inrush for motor starting, the source voltage was held constant and the starting load of the motor was added to the system. The system voltages were then calculated.

As described in Section 8D.2, the safety injection signal load is the largest load to be applied to the ESF system buses at any one time. Thus, this load was used as the running load on the buses.

8E.3 METHOD

A DAPPER model (from calculation DC-836-008, case DSTEP8S) of the diesel generator steady state full load condition was used as a base case for developing the large motor restart model (Reference calculation DC-8360-012). This DSTEP8S case 99-01 model determines the voltage at the "A" train buses when the Safety Injection loads are operating and when the Diesel Generator is supplying the load.

To evaluate the restart of large motors on the diesel generator, the steady state DAPPER model was modified to incorporate a source impedance and to create two new cases. The first DAPPER model, case DS825R, simulates the restart of the 6900 Volt Charging/SI pump (XPP43, 900 HP) and the second, case DS8101R, simulates the 00-01 restart of the 480 volt service water booster pump (XPP45, 350 HP).

The source impedance was taken as equal to the short circuit impedance of the 00-01 generator. This short circuit impedance was based on the generator test data which includes the following information:

Generator rating:	5845 KVA
Generator X/R ratio:	16
Short circuit reactance:	0.13 per unit

The steady state DAPPER model was copied and modified by adding the source impedance and turning pumps XPP43A and XPP45A off-line in order to simulate the pumps tripping. The source voltage for the model was manually adjusted until the generator terminal voltage was equal to 0.945 per unit. This is the lowest value allowed by the combination of the regulator setting limit of 95% and the $\pm$ 1/2% tolerance of the regulator. The resulting source voltage was then held constant and the starting load for each of the two motors was added into each of the two respective models. The following are the load values used:

DAPPER BUS	TAG	KW	KVAR
25	XPP43A	485	2992
101	XPP45A	231	1074

The resulting bus voltage from the two new DAPPER model cases DS825R and DS8101R were then evaluated to determine the following: 00-01

a. Acceptance of the motor starting voltage by comparing the DAPPER model case voltage with the motor's minimum required starting voltage.

b. Verification that the motor control center (MCC) contactors do not drop out during large motor restart.

The 6900 volt safety related motors were designed to start at 70% of rated voltage and, therefore, have a minimum starting voltage of 4830 volts. The 460 volt safety related motors were designed to start at 80% of rated voltage and, therefore, have a minimum starting voltage of 368 volts.

The contactors in the SQUARE D motor control centers have a dropout of 65% of nominal voltage. A value of 5% was added to account for voltage drop within the control circuit. Since the 480/120 Volt power transformers are wound to produce 120 volts on the secondary when fully loaded, a value of 70% of 480 volts (336V) on the MCC busses was used in the evaluation.

8E.4 CONCLUSION

Considering the diesel generator as the power source, the calculated voltage at the terminals of the 6900 volt CH/SI pump motor and 460 volt SWBP motor is above the minimum design starting voltage as mentioned in Section 8.3.1.1.4.2 and listed below: 00-01

		VOLTAGE		
DAPPER BUS	TAG	MIN START	CALCULATED	MARGIN
25	XPP43A	4830	6323	31%
101	XPP45A	368	415	13%

Since other safety related motors are smaller than the CH/SI pump motor and the SWBP motor for their respective voltage levels, the motor terminal voltage during the starting of all safety related motors will be above the design starting voltage for these motors.

The following table lists the voltages at each MCC bus for each of the two restart conditions. The table shows that all voltages are substantially above the 336 volt criteria and, therefore, verifies that the energized contactors will not drop out during large motor restart.

DAPPER BUS	TAG	START XPP43A	START XPP45A
1000	XMC1DA1X-P	410	431
1500	XMC1DA2X-S	409	430
2000	XMC1DA2Y-P	408	429
2500	XMC1DA2Y-S	409	430
3000	XMC1DA2Z	407	438
4000	XMC1EA1X	418	438
8000	XMC1EC1X*	418	438

* Loads on this MCC are not energized. Therefore, the voltages are the same as for bus 4000.

Tables 8E-1 and 2 list the calculated voltages of the ESF system buses and the motor terminals.

TABLE 8E-1

CALCULATED VOLTAGE LEVEL OF ESF SYSTEM BUSES AND MOTOR TERMINALS WITH A DIESEL GENERATOR AS A SOURCE AND STARTING THE 6900 VOLT CHARGING/SAFETY INJECTION PUMP MOTOR

Condition:

Initial voltage:	6804 (94.5% of 7200 volts at diesel generator terminals prior to starting motor)
Initial Load:	3505 KW
Power Source:	Diesel Generator
Motor:	Charging/Safety Injection Pump Mtr. (6900 Volt)

Resulting Voltages:

ESF System Points	Voltages	Percent of Nominal Bus Voltage
Diesel Generator	6339	88.04
7200 Volt Bus 1DA	6328	87.88
6900 Volt CH/SI Pump	6323	91.63 of motor nominal rating
480 Volt Bus 1DA1	418	87.08
480 Volt Bus 1DA2	410	85.41
480 Volt MCC 1DA2Z	407	84.79
7200 Volt Bus 1EA	6322	87.8
480 Volt MCC 1EA1X	418	87.08

APPENDIX 8F

STARTING SEQUENCE OF ESF EQUIPMENT FOLLOWING AN ACCIDENT COINCIDENT WITH A DEGRADED VOLTAGE CONDITION

8F.1 INTRODUCTION

The following study identifies the timed sequence of starting the ESF system equipment for an accident coincident with degraded voltage on the offsite power system. The accidents considered are (1) Loss of Coolant Accident (LOCA) and (2) Main Steam Line Break (MSLB). The study compares the equipment starting times during accident conditions, with a degraded voltage to the starting times assumed in the accident analyses with total loss of voltage. See Tables 8F-1 and 2.

8F.2 DISCUSSION

During these two accident scenarios, the diesel generator will start when safety injection is initiated at time zero. A maximum of 10 seconds is then required for the generator to reach the speed and voltage necessary to connect to the ESF buses.

The degraded voltage relays are set to actuate at 91.34% of nominal voltage. If the voltage drops below 80% of nominal, the undervoltage relays will actuate. A time delay of 3 seconds is provided before the degraded voltage relays signal a start to the diesel to allow for voltage dips caused by a large motor starting. However, it should be noted that for these accidents the diesel was started at time zero by safety injection; therefore the signal to start the diesel generated by the degraded voltage relay is duplicative. If the degraded voltage condition persists for 4 more seconds (now a total of 7 seconds), the 7.2 kV ESF buses are cleared. An additional time delay of 3 seconds is then provided to allow residual motor voltage to decay.

8F.3 CONCLUSION

Under the accidents discussed here, a maximum of 10 seconds is required before the diesel generator can be connected to the ESF buses. However, if there is no accident and a degraded voltage condition exists, a maximum of 13 seconds would be required before the diesel is connected.

TABLE 8F-1

DEGRADED GRID VOLTAGE COINCIDENT WITH LOCA

TIME (SECONDS)	DESCRIPTION OF EVENT	
0	Degraded voltage condition on 7.2 kV ESF Buses Loss of Coolant Accident (SI Signal - Start Diesel Generator signal).	
3	Degraded voltage detection signal.	
7	Clear 7.2 kV ESF bus (Trip incoming and feeder breakers).	
10	Close Diesel Generator breaker. Start load block #1 (Start SI/Charging Pump, Start opening valves).	
12 Note 1	SI/Charging Pump at full speed (~2 sec starting time).	98-01
15	Start RHR Pump.	
19 Note 1	RHR Pump at full speed (~4 sec starting time).	98-01
20	Start SW Pump. Start Chilled Water Pump.	00-01
24.5 Note 2	SW Pump at full speed (~4.5 sec starting time).	98-01
25	Start Component Cooling Pump.	
	Component Cooling Pump at full speed (~4 sec starting time).	
27 Note 1	Safety Injection related valves at their final position (27 sec. includes EDG start time, valve stroke time, and signal processing time).	00-01
30	Start Emergency Feedwater Pump.	
35	Start Reactor Building Cooling Units. Start Fuel Handling Building Exhaust Fan.	

TABLE 8F-1 (Continued)

DEGRADED GRID VOLTAGE COINCIDENT WITH LOCA

TIME (SECONDS)	DESCRIPTION OF EVENT	
40	Start SW Booster Pump.	
42	Emergency Feedwater Pump at Full Speed. (~12 sec starting time).	
43 Note 4	Reactor Building Cooling Units at full speed and air flow has reached operating values (8 sec delay from time of starting the fans to the time of having reached operating values of air flow per FSAR, Section 6.2.2.2.2.2).	98-01
45	Start HVAC Chiller. SW Booster Pump at full speed (5 sec starting time per FSAR, Section 6.2.2.2.2.2).	

NOTES:

1.) See FSAR Table 15.4-1. 98-01

2.) Critical case is the requirement to provide cooling water to the Diesel Generator within 1 minute from the time of starting.

3.) See FSAR, Section 15.4.2.2.2.1. 98-01

4.) See FSAR, Section 6.2.1.3.4.3.

TABLE 8F-2

DEGRADED GRID VOLTAGE COINCIDENT WITH MSLB

TIME (SECONDS)	DESCRIPTION OF EVENT	
0	Degraded voltage condition on 7.2 kV ESF Bus on Main Steam Line Break Accident (SI Signal - Start Diesel Generator signal).	
3	Degraded voltage detection signal.	
7	Clear 7.2 kV ESF bus (Trip incoming and feeder breakers).	
10	Close Diesel Generator breaker. Start load block #1 (Start SI/Charging Pump, Start opening valves).	
12 Note 1	SI/Charging Pump at full speed (~2 sec starting time).	98-01
15	Start RHR Pump.	
19 Note 1	RHR Pump at full speed (~4 sec starting time).	98-01
20	Start SW Pump. Start Chilled Water Pump.	
24.5 Note 2	SW Pump at full speed (~4.5 sec starting time).	00-01 98-01
25	Start Component Cooling Pump.	
27 Note 1	Safety Injection related valves at their final position (27 sec. includes EDG start time, valve stroke time, and signal processing time).	00-01
29	Component Cooling Pump at full speed (~4 sec starting time).	
30	Start Emergency Feedwater Pump.	
35	Start Reactor Building Cooling Units. Start Fuel Handling Building Exhaust Fan.	

TABLE 8F-2 (Continued)

DEGRADED GRID VOLTAGE COINCIDENT WITH MSLB 00-01

TIME (SECONDS)	DESCRIPTION OF EVENT
40	Start SW Booster Pump.
42 (60) Note 3	Emergency Feedwater Pump at Full Speed. (~12 sec starting time). 00-01
43 Note 4	Reactor Building Cooling Units at full speed and air flow has reached operating values 98-01 (8 sec delay from time of starting the fans to the time of having reached operating values of air flow per FSAR, Section 6.2.2.2.2.2).
45	Start HVAC Chiller. SW Booster Pump at full speed (5 sec starting time per FSAR, Section 6.2.2.2.2.2).

NOTES:

1.) See FSAR Section 15.4.2.1.2.1. 98-01

2.) Critical case is the requirement to provide cooling water to the Diesel Generator within 1 minute from the time of starting.

3.) See FSAR, Section 15.4.2.2.2.1. 98-01

4.) See FSAR, Section 6.2.1.3.4.3.

TYPICAL PROCESS USED TO SIZE A PENETRATION PROTECTION DEVICE

A COMPARISON OF THE TIME VERSUS CURRENT WITHSTANDABILITY (I^2t) OF THE PENETRATION ASSEMBLY CONDUCTORS AND THE ASSOCIATED PROTECTIVE DEVICES SHALL BE PERFORMED TO ENSURE THAT BOTH PRIMARY AND BACKUP OVERCURRENT PROTECTIVE DEVICES ARE DESIGNED TO CLEAR A FAULT CONDITION PRIOR TO REACHING THE (I^2t) CAPABILITY OF THE ASSOCIATED PENETRATION ASSEMBLY CONDUCTORS.

STEP 1. PLOT THE (I^2t) WITHSTANDABILITY OF THE PENETRATION ASSEMBLY CONDUCTOR ON A LOG-LOG TIME-CURRENT CURVE USING INFORMATION OBTAINED FROM TABLE 1.

STEP 2. CALCULATE THE MAXIMUM AVAILABLE SHORT CIRCUIT CURRENT THAT COULD BE EXPERIENCED IF A BOLTED FAULT WERE TO OCCUR BETWEEN CONDUCTORS AT THE CONDUCTOR END OF THE PENETRATION ASSEMBLY. NOTE THAT THIS STEP NEED NOT BE PERFORMED IF THE OVERCURRENT PROTECTIVE DEVICE TIME-CURRENT CHARACTERISTICS INDICATE A CLEARING TIME WHICH IS LESS THAN THE TIME REQUIRED TO REACH THE (I^2t) CURVE PLOTTED IN STEP 1 REGARDLESS OF THE SHORT CIRCUIT CURRENT VALUE (SEE NOTE 4).

STEP 3. PLOT A VERTICAL LINE TO DISPLAY THE MAXIMUM AVAILABLE SHORT CIRCUIT CURRENT CALCULATED IN STEP 2, IF APPLICABLE.

STEP 4. CHOOSE AN OVERCURRENT PROTECTIVE DEVICE WHOSE MANUFACTURER'S TIME-CURRENT CHARACTERISTICS COORDINATE WITH THE (I^2t) CURVE OF THE PENETRATION ASSEMBLY CONDUCTOR AS ESTABLISHED IN STEP 1 AND THE AVAILABLE SHORT CIRCUIT CURRENT PLOTTED IN STEP 2, IF APPLICABLE.

STEP 5. PLOT THE TIME-CURRENT CHARACTERISTICS OF THE PRIMARY AND BACKUP OVERCURRENT PROTECTIVE DEVICES AS SPECIFIED BY THE RESPECTIVE DEVICE MANUFACTURER. THE MAXIMUM BAND VALUES DISPLAYED BY THE MANUFACTURER'S OVERCURRENT PROTECTIVE DEVICE TIME-CURRENT CHARACTERISTIC CURVE SHOULD BE USED FOR CONSERVATISM.

NOTES:-

1. THIS PROCESS IS NOT THE ONLY METHOD USED TO SIZE OVERCURRENT PROTECTIVE DEVICES.
2. THIS PROCESS DOES NOT ADDRESS OVERCURRENT PROTECTION OF LOAD EQUIPMENT OR ASSOCIATED FIELD CABLING. IN MOST CASES THE ABOVE PROCEDURE IS USED TO DETERMINE WHETHER THE B/C PROTECTIVE DEVICES DESIGNED FOR LOAD EQUIPMENT AND FIELD CABLING PROTECTION PROVIDE ADEQUATE PROTECTION FOR ASSOCIATED PENETRATION CONDUCTORS.
3. PRIMARY AND BACKUP OVERCURRENT DEVICES USED FOR PENETRATION PROTECTION MAY OR MAY NOT BE COORDINATED WITH EACH OTHER OR UPSTREAM SYSTEM PROTECTION.
4. ALTHOUGH NOT A REQUIREMENT OF NRC REGULATORY GUIDE 1.63, WHICH ADDRESSES ONLY PENETRATION PROTECTION, THE PROTECTIVE DEVICE SHALL HAVE AN INTERRUPTING RATING SUFFICIENT FOR THE SYSTEM VOLTAGE AND THE MAXIMUM SHORT CIRCUIT CURRENT WHICH IS AVAILABLE AT THE LINE TERMINALS OF THE PROTECTIVE DEVICE.

TABLE 1

THE FOLLOWING AMPERE VALUES WERE OBTAINED BY CALCULATION USING ICEA P-32-382 FORMULA AND D.G.O'BRIEN'S TEST REPORT NO. ER-262. INFORMATION/ACTUAL CALCULATIONS ARE DOCUMENTED IN G/C CALCULATION NO. DC-350001/56, WHICH HAS BEEN REPLACED BY CALCULATION NOS. DC08470-006 AND DC08470-013.

ITEM	CONDUCTOR SIZE	I^2t	IF t=0.1 SECONDS, I1	IF t=75 SECONDS, I1	IF t=100 SECONDS, I1	IF t=200 SECONDS, I1	IF t=300 SECONDS, I1
1	#16 AWG	50,563.93	711.22	25.97	22.49	15.90	12.99
2	#12 AWG	321,848.91	1,608.11	65.73	56.92	40.25	32.87
3	#4 AWG	13,229,718	11,586.79	420.15	363.86	257.29	210.08
4	*1/0 AWG	64,742,538	29,138.57	1,062.47	920.56	650.93	531.18
5	250 MCM	474,956,258	68,917.87	2,510.58	2,174.35	1,541.83	1,258.25

THE FOLLOWING AMPERE VALUES WERE OBTAINED FROM D.G. O'BRIEN REPORT NO. ER-262:

ITEM	CONTINUOUS CURRENT	1000 SECOND CURRENT	60 SECOND SHORT TIME OVERLOAD
1	5 AMPS		
2	20 AMPS*	21	45 AMPS*
3	70 AMPS*	129	490 AMPS*
4	125 AMPS*	231	903 AMPS*
5	275 AMPS*	471	1925 AMPS*

* CONFIRMED BY D.G. O'BRIEN TESTS

NOTES:

1. THE 60 SECOND VALUE FOR #12 AWG CONDUCTORS IS LESS THAN 7X CONTINUOUS CURRENT RATING (FAILURES EXPERIENCED AT 140 AMPS).
2. 1000 MCM PENETRATION ASSEMBLY CONDUCTORS ARE USED SOLELY FOR 7.2 KV REACTOR COOLANT PUMPS XPP-30A, B, AND C. THE (I^2t) WITHSTANDABILITY OF 1000 MCM PENETRATION ASSEMBLY CONDUCTORS WAS PLOTTED ON A LOG-LOG TIME CURRENT CURVE USING INFORMATION SPECIFIED BY D.G. O'BRIEN. SINCE ALL EXISTING 1000 MCM PENETRATION ASSEMBLY CONDUCTORS ARE USED (i.e., NO SPARES) AND SINCE FUTURE REQUIREMENTS FOR 1000 MCM PENETRATION ASSEMBLY CONDUCTORS ARE NOT ANTICIPATED, TIME-CURRENT VALUES ESTABLISHING (I^2t) WITHSTANDABILITY OF THE 1000 MCM CONDUCTORS WILL NOT BE IDENTIFIED.
3. CALCULATED CURRENT VALUES FOR TIMES OVER 100 SECONDS ARE CONSERVATIVE SINCE THE ICEA STANDARD P-32-382 FORMULA DOES NOT COMPENSATE FOR HEAT DISPERSION TO THE ENVIRONMENT.

TYPICAL METHODOLOGY USED TO ESTABLISH TEST SETPOINTS AND RESPONSE TIMES OF PENETRATION PROTECTION DEVICES

TEST SETPOINT AND ASSOCIATED RESPONSE TIME VALUES ARE ESTABLISHED TO ENSURE THAT THE PROTECTION DEVICES WILL OPERATE IN ACCORDANCE WITH MANUFACTURER'S DESIGN CHARACTERISTICS AND THAT THE OPERATION WILL OCCUR PRIOR TO REACHING THE (I^2t) CAPABILITY OF THEIR ASSOCIATED PENETRATION ASSEMBLY CONDUCTORS, WITH ADEQUATE MARGIN (i.e., THE POINT ESTABLISHED BY THE TEST SETPOINT/RESPONSE TIME VALUE SHOULD AS A MINIMUM BE EQUAL TO THAT ESTABLISHED BY THE MAXIMUM BAND OF THE PROTECTIVE DEVICE, AND SHOULD AS A MAXIMUM BE LESS THAN THE VALUE OF PENETRATION ASSEMBLY CONDUCTOR (I^2t) CAPABILITY ESTABLISHED BY CALCULATION AS PLOTTED ON A TIME VERSUS CURRENT CURVE).

480V SWITCHGEAR POWER CIRCUIT BREAKERS

THE METHOD USED TO ESTABLISH TEST SETPOINTS AND RESPONSE TIMES ASSOCIATED WITH 480V SWITCHGEAR POWER CIRCUIT BREAKERS IS AS FOLLOWS:

ESTABLISH TEST SETPOINTS AND ASSOCIATED RESPONSE TIMES IN ACCORDANCE WITH GOULD/ITE SWITCHGEAR INSTRUCTION MANUAL BULLETIN 10-3.1-3 TABLE 4, PAGE 9 AND THE APPROPRIATE SHEETS OF E/K, THE RELAY AND BREAKER SETTING DWG. SS-205-XXX.

EXAMPLE:

TEST SET POINT

LONG-TIME DELAY = 3 X LONG-TIME P.U. AMP SETTING
SHORT-TIME DELAY = 1.5 X SHORT-TIME P.U. AMP SETTING
INSTANTANEOUS RELAY = 1.5 X INSTANTANEOUS P.U. AMP SETTING

RESPONSE TIME

LONG-TIME RELAY ≤ 3 X HIGH RANGE OF DEVICE BAND SETTING
SHORT-TIME DELAY ≤ 3 X HIGH RANGE OF DEVICE BAND SETTING
INSTANTANEOUS ≤ X 0.05 SECONDS (0.79 SECONDS)

NOTE:

SOLID STATE TRIP DEVICE TYPE/AMPS SELECTION, AND RELAY SETTING INFORMATION SHOULD BE OBTAINED FROM E/K, THE DRAWING SS-205-XXX.

480V AC, 120V AC, AND 125V DC MOLDED CASE CIRCUIT BREAKERS

THE METHOD USED TO ESTABLISH TEST SETPOINTS AND RESPONSE TIMES OF MOLDED CASE CIRCUIT BREAKERS LOCATED IN MOTOR CONTROL CENTERS AND POWER DISTRIBUTION PANELS IS AS FOLLOWS:

ESTABLISH TEST SETPOINTS AND ASSOCIATED RESPONSE TIMES FOR THERMAL-MAGNETIC CIRCUIT BREAKERS IN ACCORDANCE WITH NEMA STANDARD AB-2.

EXAMPLE:

TEST SET POINT: 3 X BREAKER AMPERE RATING

RESPONSE TIME: MAXIMUM TRIPPING TIME (SECONDS) AS IDENTIFIED IN NEMA STANDARD AB-2 1980, PART 2, TABLE 2-1.

ESTABLISH TEST SETPOINTS AND ASSOCIATED RESPONSE TIMES FOR MAGNETIC CIRCUIT BREAKERS IN ACCORDANCE WITH MANUFACTURER'S RECOMMENDATIONS.

EXAMPLE:

TEST SET POINT: 1.5 X BREAKER AMPERE RATING

RESPONSE TIME: INSTANTANEOUS TRIPPING IN THE REGION OF ½ CYCLE (0.0083 SECONDS) IS REPRESENTED BY OVAL ON THE FUSE CHART. RESPONSE TIME MEASUREMENT IS NOT REQUIRED SINCE FAILURE OF THE BREAKER TO TRIP INSTANTANEOUSLY WOULD CAUSE DAMAGE TO THE UNIT AND CONSEQUENT REPLACEMENT.

FUSES

THE METHOD USED TO ESTABLISH TEST SETPOINTS AND RESPONSE TIMES OF FUSES IS AS FOLLOWS:

ESTABLISH TEST SETPOINTS OF FUSES IN ACCORDANCE WITH VENDOR SUPPLIED RESISTANCE VALUES WHICH HAVE BEEN OBTAINED FOR EACH SPECIFIC TYPE AND SIZE OF FUSE USED. RESISTANCE VALUES AT 40°C WERE DERIVED BY CALCULATION USING 25°C VALUES PROVIDED BY THE FUSE MANUFACTURER.

TEST SET POINT RESISTANCE VALUES ARE AS FOLLOWS:

MANUFACTURER	TYPE AND SIZE	MATERIAL FUSE LINK	RESISTANCE IN MILLIOHMS (MINIMUM) AT 25°C (77°F)	(MINIMUM) (AT 40°C (104°F))	(MAXIMUM) (AT 25°C (77°F))	(MAXIMUM) (AT 40°C (104°F))
BUSS	ABC-3	COPPER	≥ 41.0	≥ 43.30	49.0	51.84
	ABC-5	ZINC	≥ 24.0	≥ 25.41	33.0	35.05
	ABC-8	ZINC	≥ 20.5	≥ 21.71	25.0	26.55
	P/N2432859	CUILOING METAL	≥ 33.5	N/A	82.5	N/A
	NON-3	AG PLATED CU	≥ 45.0	≥ 41.7	57.0	65.72
	NON-6	ZINC	≥ 18.0	≥ 19.72	24.0	25.49
	NON-15 (CLASS H)	ZINC	≥ 6.05	≥ 6.42	8.03	8.53
	(CLASS K5)	COPPER	≥ 14.10	≥ 14.69	16.5	17.46
	FNM-3.2	CONSTANTAN	≥ 65.0	≥ 65.0	88.0	88.82
	FRN-3.2 OR FRN-12.7	COPPER	≥ 100.0	≥ 105.9	135.0	142.8
	FNM-20	COPPER	≥ 35.0	≥ 19.35	84.0	88.87
	FNM 810	CONSTANTAN	≥ 30.0	≥ 30.0	30.0	30.81
	FRN-R15	65% CU, 18% NI, 17% ZN	≥ 14.0	≥ 15.07	17.0	18.24
	FRN-5	COPPER	≥ 33.0	≥ 34.91	45.0	47.61
	FRN-R20	UNKNOWN	≥ 1.0	N/A	1.3	N/A
GOULD	OT-3	UNKNOWN	≥ 86.8	N/A	128.8	N/A
	OT-6	ZINC	≥ 19.8	≥ 20.7	25.4	26.97
	OT-10	ZINC	≥ 14.0	≥ 14.97	17.4	18.48
	OT-15	COPPER	≥ 6.79	≥ 6.55	7.8	8.25
	TRS150R	COPPER	> 0.169	> 0.695	0.720	0.762
	TRS200R	COPPER	> 0.401	> 0.433	0.460	0.487
	A2SX50-4	COPPER	> 1.62	> 1.71	1.97	2.06
	A2Y6-1	[illegible]	> 22.4	N/A	26.6	N/A
	A2Y15-1	ZINC	> 8.13	> 8.61	1.10	9.66
	A2Y20-1	SILVER	> 4.37	> 4.53	4.24	5.82
	A2Y50-1	SILVER	> 1.66	> 1.76	1.81	1.92
	A2Y60-1	SILVER	> 1.76	> 1.34	1.46	1.55
	A2Y6R	UNKNOWN	> 20.6	N/A	25.9	N/A
	A2X15R	UNKNOWN	≥ 7.7	N/A	9.8	
	A2X20R	UNKNOWN	≥ 7.65	N/A	8.7	
	A2X50R	UNKNOWN	≥ 1.5	N/A	1.73	
	A2X60R	UNKNOWN	≥ 1.21	N/A	1.5	
	TR3.2R	UNKNOWN	≥ 197.0	N/A	277.0	
	TR6R	UNKNOWN	≥ 23.4	N/A	30.6	
	TR10R	UNKNOWN	≥ 21.0	N/A	31.5	
	TR15R	UNKNOWN	≥ 18.8	N/A	22.5	
	TR30R	UNKNOWN	≥ 1.7	N/A	1.36	N/A
BUSS	ABS5	ZINC	≥ 35.0	≥ 26.55	34.0	36.11
	FWX-10	CUILOING METAL	≥ 37.5	N/A	52.5	N/A
	NON-10	ZINC	≥ 11.0	≥ 11.50	18.0	19.12
	KTN 25	AG PLATED CU	≥ 24.5	≥ 25.97	30.0	31.8
	KTN-R15	AG PLATED CU	≥ 6.5	≥ 6.89	8.05	8.53
	KTN-R20	AG PLATED CU	≥ 5.7	≥ 6.04	7.1	7.53
	KTK-R50	AG PLATED CU	≥ 1.63	≥ 1.72	2.1	2.23
	KTK-R60	AG PLATED CU	≥ 1.1	≥ 1.12	1.4	1.48
	KTN 8G	AG PLATED CU	≥ 31.5	≥ 33.39	37.5	39.75
	KTN-R15	AG PLATED CU	≥ 8.0	≥ 8.45	9.2	9.75
	KTK-R20	AG PLATED CU	≥ 3.75	≥ 3.98	4.5	4.77
	KTK-R50	AG PLATED CU	≥ 1.5	≥ 1.58	1.85	1.96
	KTK-R60	AG PLATED CU	≥ 1.2	≥ 1.27	1.5	1.59
	JJS-50	SILVER	≥ 2.3	≥ 2.44	2.8	2.97
	FNQ-15	BRASS	≥ 5.50	≥ 5.77	7.30	7.52
LITTELFUSE	313301	UNKNOWN	> 318.75	≥ 334.50	431.25	452.81
	313035	UNKNOWN	> 20.47	≥ 21.01	28.18	29.59
	314003	UNKNOWN	> 31.02	N/A	48.38	N/A
	314005	UNKNOWN	> 20.75	N/A	35.95	N/A
	314006	UNKNOWN	> 21.56	N/A	27.44	N/A

RESPONSE TIMES ARE NOT APPLICABLE AND ARE REPRESENTED BY (N/A) ON THE FUSE CHART.

NOTES:

1. FUSES WHICH HAVE BEEN IN SERVICE SHALL BE ALLOWED TO COOL TO ROOM TEMPERATURE BEFORE RESISTANCE TEST MEASUREMENTS ARE MADE. FOR CONSERVATISM THE 40°C RESISTANCE VALUES ARE APPLICABLE FOR ESTABLISHING TEST SETPOINTS. (EXCEPTIONS: BUSS 2432859, FWX-10 FRN-R80; GOULD A2K6R, A2X15R, A2K20R, A2K50R, A2K60R, A2Y6-1 OT-3, TR3.2R, TR6R, TR10R, TR15R, TR30R; LITTELFUSE 314003, 314005, 314006 FUSES SHALL BE TESTED AT 25°C (77°F ±5°F).
2. THE APPROPRIATE FUSE MANUFACTURER SHALL CONFIRM THAT THE MINIMUM RESISTANCE VALUES AT 25°C AND THE FUSE LINK MATERIAL OF APPLICABLE FUSES INSTALLED COMPLIES WITH THE ABOVE INFORMATION.
3. THE 25°C RESISTANCE VALUE CAN BE SUBSTITUTED FOR ITS CORRESPONDING 40°C RESISTANCE VALUE (TEST SETPOINT VALUE) AS LONG AS THE AMBIENT TEMPERATURE IS VERIFIED TO BE 25°C (77°F ± 5°F).
4. BUSS FUSE PART NO. 2432859 IS A SPECIAL FUSE RECOMMENDED BY WESTINGHOUSE BUT PROCURED FROM BUSSMAN. SEE WESTINGHOUSE LETTER NSD-78-12, DATED 12-19-78 FOR FURTHER DETAILS.

GENERAL NOTES:-

1. THIS DRAWING IDENTIFIES OVERCURRENT PROTECTION DEVICES ASSIGNED TO PROTECT CONTAINMENT PENETRATION ASSEMBLY CONDUCTORS IN ACCORDANCE WITH THE REQUIREMENTS OF NRC REGULATORY GUIDE 1.63, REVISION 1, DATED MAY 1977, AS INTERPRETED BY G/C INC.
2. THIS DRAWING IS IDENTIFIED AS NUCLEAR SAFETY RELATED SINCE IT CONTAINS INFORMATION FOR BOTH NON-CLASS 1E AND CLASS 1E PROTECTION DEVICES.
3. ALTHOUGH NRC REGULATORY GUIDE 1.63 REQUIRES THE USE OF TWO PROTECTIVE DEVICES WHEN PENETRATIONS CANNOT WITHSTAND THE MAXIMUM FAULT CURRENT INDEFINITELY, IT PERMITS THE USE OF NON-CLASS 1E PROTECTIVE DEVICES FOR PROTECTION OF NON-CLASS 1E CIRCUITS. HOWEVER, TO ENSURE THE CONTINUITY OF POWER TO CLASS 1E CIRCUITS, THE FAULT CURRENT PROTECTION DEVICES FOR CLASS 1E CIRCUITS MUST ALSO BE CLASS 1E.
4. THE 125-TRIP ENERGY OF THE PROTECTIVE DEVICE SHALL NOT EXCEED THE SHORT CIRCUIT CURRENT WITHSTANDABILITY OF THE CONDUCTOR BEING PROTECTED.
5. THE SPECIFIC TEST SETPOINT AND ASSOCIATED RESPONSE TIME FOR EACH LISTED PROTECTIVE DEVICE WAS ESTABLISHED BY VENDOR SUPPLIED RECOMMENDATIONS AND/OR ENGINEERING EVALUATION.
6. EXCEPTIONS TO THE METHODOLOGY USED TO ESTABLISH SPECIFIC TEST SETPOINTS AND ASSOCIATED RESPONSE TIMES MAY EXIST. SPECIFIC TEST SETPOINT AND ASSOCIATED RESPONSE TIME VALUES MAY NOT ALWAYS BE CONSISTENT WITH VALUES DERIVED BY USING THE STANDARD METHODS.
7. CONTAINMENT PENETRATION ASSEMBLIES USED ON V.C. SUMMER NUCLEAR STATION WERE TESTED IN ACCORDANCE WITH IEEE 317 AND NRC REGULATORY GUIDE 1.63 USING MAXIMUM SHORT CIRCUIT CURRENT VALUES AND TIME REQUIREMENTS ESTABLISHED IN ACCORDANCE WITH ICEA STANDARD P-32-382 FORMULA.
8. AN EVALUATION TO ENSURE THAT ADEQUATE PRIMARY AND BACKUP OVERCURRENT PROTECTION AND/OR JUSTIFICATION EXISTS TO CONFIRM V.C. SUMMER NUCLEAR STATION COMPLIANCE TO NRC REGULATORY GUIDE 1.63 REQUIREMENTS IS DOCUMENTED IN CALCULATION NO. DC-350001/56 WHICH HAS BEEN REPLACED BY CALCULATION NOS. DC08470-006 AND DC08470-013.
9. G/C INC. SHOULD REVIEW ANY DESIGN CHANGES INVOLVING SIZING, TEST SETPOINTS, AND RESPONSE TIMES OF EXISTING AND NEW PENETRATION PROTECTIVE DEVICES FOR CONCURRENCE WITH NRC REGULATORY GUIDE 1.63 PRIOR TO COMPLETION OF THOSE DESIGN CHANGES.
10. CALCULATION NO. DC-350001/56 * WAS REPLACED BY CALCULATION NOS. DC08470-006 AND DC08470-013. CALCULATION NO. DC08470-006 PROVIDES THE DESIGN BASES FOR ESTABLISHING THE PENETRATION PROTECTION DEVICE TEST SETPOINTS. CALCULATION NO. DC08470-013 EVALUTES THE PRIMARY AND BACKUP PROTECTION FOR EACH SET OF PINS FEED THROUGH THE PENETRATION BASED ON THE DEVICE SIZES AND SETTINGS TO ENSURE COMPLIANCE WITH THE REQUIREMENTS OF NRC REGULATORY GUIDE 1.63. THESE CALCULATIONS SHALL BE REVISED AS REQUIRED WHENEVER ANY INFORMATION AS SHOWN ON THIS DRAWING IS CHANGED OR NEW INFORMATION ADDED.
11. PERIODIC TESTING AND SURVEILLANCE OF CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES SHALL BE PERFORMED IN ACCORDANCE WITH THE REQUIREMENTS ESTABLISHED BY TECHNICAL SPECIFICATION, SECTION 3/4.8.4.
12. ACCEPTABLE REPLACEMENT FUSES IDENTIFIED ON TABLE 1 OF S-200-961 (CLASS 1E AND PENETRATION PROTECTION FUSE LIST) MAY BE USED IN LIEU OF THOSES SHOWN ON SHEETS 5 THROUGH 10 OF THIS DRAWING PROVIDING THAT THE APPLICABLE TEST SETPOINT (RESISTANCE VALUES) ARE USED.

MANUFACTURER	TYPE	MATERIAL FUSE LINK	(MINIMUM) AT 25°C (77°F)	(MAXIMUM) AT 25°C (77°F)	(MINIMUM) AT 40°C (104°F)	(MAXIMUM) AT 40°C (104°F)
* BUSSMAN	KTS-R80	UNKNOWN	≥ 1.0 MILLIOHM	1.3 MILLIOHMS		
BUSSMAN	JJS-500	UNKNOWN	≥ 120 MICROHMS	150 MICROHMS		
BUSSMAN	KTU-800	SILVER	≥ 76 MICROHMS	90 MICROHMS		
GOULD	A6K-R80		≥			
GOULD	A6T-500		≥			
GOULD	A4BY-800		≥			
BUSSMAN	NON-2	COPPER	≥ 72.5 MILLIOHMS	92.5 MILLIOHMS	≥ 76.7 MILLIOHMS	97.8 MILLIOHMS
BUSSMAN	NON-1½	COPPER	≥ 115.0 MILLIOHMS	150.0 MILLIOHMS	≥ 121.6 MILLIOHMS	158.7 MILLIOHMS

THIS IS A NUCLEAR SAFETY RELATED DOCUMENT

FSAR Figure 8O-1

AMENDMENT 00-01
DECEMBER 2000

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7.2 KV SWITCHGEAR

OVERCURRENT PROTECTION DEVICE									PENETRATION		LOAD	
LOCATION		APPLICATION		CLASS								
PARENT DEVICE NO.	UNIT NO. OR TAG NO.	PRI	BACK-UP	1E	NON-1E	TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP	CONDUCTOR SIZE	EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS
XSW1A	3		X	X		7 KV G.E. BREAKER 1AC66A2A 1AC77AB03A	LONG TIME 5544 AMPS LONG TIME 17,000 AMPS	≤15.33 SEC ≤2.0 SEC	0106	1000 MCM	XPP0030A-RC REACTOR COOLANT PUMP A	BUS 1A EMERGENCY FEED
XSW1A	5		X	X		7 KV G.E. BREAKER 1AC66A2A 1AC77AB03A	LONG TIME 5544 AMPS LONG TIME 17,000 AMPS	≤15.33 SEC ≤2.0 SEC	0106	1000 MCM	XPP0030A-RC REACTOR COOLANT PUMP A	BUS 1A NORMAL FEED
XSW1A	6	X		X		7 KV G.E. BREAKER 1AC66K2A	LONG TIME 3000 AMPS INSTANT 5660 AMPS	≤15.73 SEC N/A	0105	1000 MCM	XPP0030A-RC REACTOR COOLANT PUMP A	
XSW1B	3		X	X		7 KV G.E. BREAKER 1AC66A2A 1AC77AB03A	LONG TIME 5544 AMPS LONG TIME 17,000 AMPS	≤15.33 SEC ≤2.0 SEC	0003	1000 MCM	XPP0030B-RC REACTOR COOLANT PUMP B	BUS 1B EMERGENCY FEED
XSW1B	5		X	X		7 KV G.E. BREAKER 1AC66A2A 1AC77AB03A	LONG TIME 5544 AMPS LONG TIME 17,000 AMPS	≤15.33 SEC ≤2.0 SEC	0003	1000 MCM	XPP0030B-RC REACTOR COOLANT PUMP B	BUS 1B NORMAL FEED
XSW1B	3	X		X		7 KV G.E. BREAKER 1AC66K2A	LONG TIME 3060 AMPS INSTANT 5660 AMPS	≤15.73 SEC N/A	0503	1000 MCM	XPP0030B-RC REACTOR COOLANT PUMP B	
XSW1C	3	X		X		7 KV G.E. BREAKER 1AC66K2A	LONG TIME 3060 AMPS INSTANT 3660 AMPS	≤15.73 SEC N/A	0031	1000 MCM	XPP0030C-RC REACTOR COOLANT PUMP C	
XSW1C	6		X	X		7 KV G.E. BREAKER 1AC66A2A 1AC77AB03A	LONG TIME 5544 AMPS LONG TIME 17,000 AMPS	≤15.33 SEC ≤2.0 SEC	0031	1000 MCM	XPP0030C-RC REACTOR COOLANT PUMP C	BUS 1C NORMAL FEED
XSW1C	11		X	X		7 KV G.E. BREAKER 1AC66A2A 1AC77AB03A	LONG TIME 5544 AMPS LONG TIME 17,000 AMPS	≤15.33 SEC ≤2.0 SEC	0031	1000 MCM	XPP0030C-RC REACTOR COOLANT PUMP C	BUS 1C EMERGENCY FEED

480V SWITCHGEAR

OVERCURRENT PROTECTION DEVICE									PENETRATION		LOAD	
LOCATION		APPLICATION		CLASS								
PARENT DEVICE NO.	UNIT NO. OR TAG NO.	PRI	BACK-UP	1E	NON-1E	TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP	CONDUCTOR SIZE	EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS
XSW1A3	1C	X		X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 540 AMPS SHORT TIME 2700 AMPS INSTANT 3375 AMPS	≤86 SEC ≤0.17 SEC ≤0.09 SEC	0019	250 MCM	XFN0087A-AH CRDM COOLING SYSTEM FAN A	SEE NOTE 1
XSW1A3	2A	X		X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 263 AMPS SHORT TIME 1313 AMPS INSTANT 1800 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0013	250 MCM	XFN0085A-AH RB REACTOR COMPARTMENT COOLING FAN A	SEE NOTE 1
XSW1A3	2C	X		X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 744 AMPS SHORT TIME N/A INSTANT 4050 AMPS	≤86 SEC N/A ≤0.09 SEC	0015	250 MCM	XCR0004-FH RB POLAR CRANE	SEE NOTE 1
XSW1A3	3A	X		X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 540 AMPS SHORT TIME 2700 AMPS INSTANT 3375 AMPS	≤90 SEC ≤0.17 SEC ≤0.09 SEC	0019	250 MCM	XFN0087D-AH CRDM COOLING SYSTEM FAN D	SEE NOTE 1
XSW1A3	4B		X	X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 4800 AMPS SHORT TIME 7200 AMPS INSTANT N/A	≤17 SEC ≤0.50 SEC N/A	0015 0019	250 MCM	XFN0087A, 0087D, 0085A-AH, XCR0004-FH	XSW1A3 MAIN INCOMING SEE NOTE 1
XSW1A3	4C		X	X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 3000 AMPS SHORT TIME 4500 AMPS INSTANT N/A	≤12 SEC ≤0.32 SEC N/A	0013 0019	250 MCM	XFN0087A, 0087C, 0087D, 0085A-AH, XCR0004-FH	BUS TIE TO XSW1C3 SEE NOTE 1
XSW1B3	2B	X		X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 525 AMPS SHORT TIME 2230 AMPS INSTANT 3000 AMPS	≤90 SEC ≤0.17 SEC ≤0.09 SEC	0018	250 MCM	XFN0087B-AH CRDM COOLING SYSTEM FAN B	SEE NOTE 1
XSW1B3	2A	X		X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 525 AMPS SHORT TIME 1125 AMPS INSTANT 1500 AMPS	≤12 SEC ≤0.17 SEC ≤0.09 SEC	0015	250 MCM	XFN0085B-AH RB REACTOR COMPARTMENT COOLING FAN B	SEE NOTE 1
XSW1B3	3B		X	X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 4800 AMPS SHORT TIME 8000 AMPS INSTANT N/A	≤12 SEC ≤0.32 SEC N/A	0019	250 MCM	XFN0087B-AH CRDM COOLING SYSTEM FAN B	EMERGENCY FEED FROM XSW1DB1 SEE NOTE 1
XSW1B3	4B		X	X		480V ITE POWER CIRCUIT BREAKER	LONG TIME N/A SHORT TIME 8000 AMPS INSTANT N/A	≤12 SEC ≤0.34 SEC N/A	0018	250 MCM	XFN0087B-AH CRDM COOLING SYSTEM FAN B	XSW1B3 MAIN INCOMING SEE NOTE 1
XSW1C3	2B	X		X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 540 AMPS SHORT TIME 2700 AMPS INSTANT 3375 AMPS	≤84 SEC ≤0.17 SEC ≤0.09 SEC	0019	250 MCM	XFN0087C-AH CRDM COOLING SYSTEM FAN C	SEE NOTE 1
XSW1C3	3B		X	X		480V ITE POWER CIRCUIT BREAKER	LONG TIME 4800 AMPS SHORT TIME 7200 AMPS INSTANT N/A	≤12 SEC ≤0.50 SEC N/A	0019	250 MCM	XFN0087C-AH CRDM COOLING SYSTEM FAN C	XSW1C3 MAIN INCOMING SEE NOTE 1
XSW1DA1	4B		X		X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 8300 AMPS SHORT TIME 8000 AMPS INSTANT N/A	≤12 SEC ≤0.33 SEC N/A	0010 0011	250 MCM	XFN0096C, 0097C, 0096A, 0097A-AH	XSW1DA1 MAIN INCOMING SEE NOTE 1
XSW1DA1	5B	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 1260 AMPS SHORT TIME 3400 AMPS INSTANT 7200 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0010	250 MCM	XFN0096C-AH RB COOLING UNIT XFN65A NORMAL MOTOR	SEE NOTE 1
XSW1DA1	5C	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 825 AMPS SHORT TIME 1500 AMPS INSTANT 2250 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0011	250 MCM	XFN0097A-AH RB COOLING UNIT XFN64A EMERGENCY MOTOR	SEE NOTE 1
XSW1DA1	6B	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 1260 AMPS SHORT TIME 5400 AMPS INSTANT 7200 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0017	250 MCM	XFN0096A-AH RB COOLING UNIT XFN64A NORMAL MOTOR	SEE NOTE 1
XSW1DA1	6C	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 825 AMPS SHORT TIME 1500 AMPS INSTANT 2250 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0010	250 MCM	XFN0097C-AH RB COOLING UNIT XFN65A EMERGENCY MOTOR	SEE NOTE 1
XSW1DA2	4B		X		X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 4800 AMPS SHORT TIME 7200 AMPS INSTANT N/A	≤17 SEC ≤0.50 SEC N/A	0010	250 MCM	XHR0004A-HR H_2 RECOMBINER POWER PANEL	XSW1DA2 MAIN INCOMING SEE NOTE 1
XSW1DA2	5C	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 315 AMPS SHORT TIME N/A INSTANT 900 AMPS	≤17 SEC N/A ≤0.09 SEC	0011	250 MCM	XHR0004A-HR H_2 RECOMBINER POWER PANEL	SEE NOTE 1
XSW1DB1	4B		X		X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 8300 AMPS SHORT TIME 8000 AMPS INSTANT N/A	≤12 SEC ≤0.36 SEC N/A	0007 0014	250 MCM	XFN0096B, 0097B, 0096D, 0097D-AH	XSW1DB1 MAIN INCOMING SEE NOTE 1
XSW1DB1	6C	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 825 AMPS SHORT TIME 1500 AMPS INSTANT 2250 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0014	250 MCM	XFN0097C-AH RB COOLING UNIT XFN65B EMERGENCY MOTOR	SEE NOTE 1
XSW1DB1	6D	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 825 AMPS SHORT TIME 1500 AMPS INSTANT 2250 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0007	250 MCM	XFN0097B-AH RB COOLING UNIT XFN64B EMERGENCY MOTOR	SEE NOTE 1
XSW1DB1	7B	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 1260 AMPS SHORT TIME 3400 AMPS INSTANT 7200 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0007	250 MCM	XFN0096B-AH RB COOLING UNIT XFN64B NORMAL MOTOR	SEE NOTE 1
XSW1DB1	7C	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 1260 AMPS SHORT TIME 5400 AMPS INSTANT 7200 AMPS	≤30 SEC ≤0.17 SEC ≤0.09 SEC	0014	250 MCM	XFN0096D-AH RB COOLING UNIT XFN65B NORMAL MOTOR	SEE NOTE 1
XSW1DB2	4B		X		X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 4800 AMPS SHORT TIME 7200 AMPS INSTANT N/A	≤12 SEC ≤0.50 SEC N/A	0007	250 MCM	XHR0004B-HR H_2 RECOMBINER POWER PANEL	XSW1DB2 MAIN INCOMING SEE NOTE 1
XSW1DB2	5C	X			X	480V ITE POWER CIRCUIT BREAKER	LONG TIME 315 AMPS SHORT TIME N/A INSTANT 900 AMPS	≤12 SEC N/A ≤0.09 SEC	0014	250 MCM	XHR0004B-HR H_2 RECOMBINER POWER PANEL	SEE NOTE 1

480V MOTOR CONTROL CENTERS

OVERCURRENT PROTECTION DEVICE									PENETRATION		LOAD	
LOCATION		APPLICATION		CLASS								
PARENT DEVICE NO.	UNIT NO. OR TAG NO.	PRI	BACK-UP	1E	NON-1E	TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP	CONDUCTOR SIZE	EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS
XMC1A3X	1AC	X		X		SQUARE D FAL36080	240 AMPS	≤200 SEC	0053	#4 AWG	XTF0003-ED/ RECEPTACLE TRANSFORMER 3	
XMC1A3X	1AC		X	X		SQUARE D 1FL34080	240 AMPS	≤200 SEC	0053	#4 AWG	XTF0003-ED/ RECEPTACLE TRANSFORMER 3	
XMC1A3X	3IC	X		X		SQUARE D FAL36015	40 AMPS	≤100 SEC	0018	#4 AWG	XDD 0001-IC TERMINAL BOX	
XMC1A3X	3IC		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0018	#4 AWG	XDD 0001-IC TERMINAL BOX	
XMC1A3X	4AD	X		X		SQUARE D FAL36015-13M	225 AMPS	N/A	0053	#4 AWG	XPP0059A-WD/ INCORE INSTRUMENT CHASE SUMP PUMP A	
XMC1A3X	4AD		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0053	#4 AWG	XPP0059A-WD/ INCORE INSTRUMENT CHASE SUMP PUMP A	
XMC1A3X	4EH	X		X		SQUARE D FAL3607-12M	195 AMPS	N/A	0053	#4 AWG	XPP0115A-WD/ RB SUMP PUMP A	
XMC1A3X	4EH		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0053	#4 AWG	XPP0115A-WD/ RB SUMP PUMP A	
XMC1A3X	4IL	X		X		SQUARE D FAL36015-13M	225 AMPS	N/A	0018	#4 AWG	XPP0138-WD/ LEAK DETECTION SUMP PUMP	
XMC1A3X	4IL		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0018	#4 AWG	XPP0138-WD/ LEAK DETECTION SUMP PUMP	
XMC1A3X	6CC	X		X		SQUARE D FAL36070-16M	750 AMPS	N/A	0053	#1/0 AWG	XPP0051A-WL/ RC DRAIN TANK - PUMP A	
XMC1A3X	6CC		X	X		SQUARE D 1FL34070	210 AMPS	≤200 SEC	0053	#1/0 AWG	XPP0051A-WL/ RC DRAIN TANK - PUMP A	
XMC1A3X	8AD	X		X		SQUARE D FAL36050-16M	750 AMPS	N/A	0053	#1/0 AWG	XFN0078A-AH/ SECONDARY COMPT (LOOP C) COOLING FAN A	
XMC1A3X	8AD		X	X		SQUARE D 1FL36050	150 AMPS	≤200 SEC	0053	#1/0 AWG	XFN0078A-AH/ SECONDARY COMPT (LOOP C) COOLING FAN A	
XMC1A3X	9IR	X		X		SQUARE D FAL3603-11M	45 AMPS	N/A	0053	#4 AWG	XVT0593A-CC/ NOV REACTOR COOLANT PUMP A THERMAL BARRIER	
XMC1A3X	9IR		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0053	#4 AWG	XVT0593A-CC/ NOV REACTOR COOLANT PUMP A THERMAL BARRIER	
XMC1A3X	10CF	X		X		SQUARE D FAL36050-16M	750 AMPS	N/A	0053	#1/0 AWG	XFN0084-AH/ SECONDARY COMPT (LOOP B) COOLING FAN A	
XMC1A3X	10CF		X	X		SQUARE D 1FL36050	150 AMPS	≤200 SEC	0053	#1/0 AWG	XFN0089A-AH/ SECONDARY COMPT (LOOP B) COOLING FAN A	
XMC1A3X	10EK	X		X		SQUARE D FAL36100-16M	1500 AMPS	N/A	0018	#1/0 AWG	XFN0088A-AH/AB CHARCOAL CLEANUP UNIT FAN A	
XMC1A3X	10EK		X	X		SQUARE D 1FL36070	210 AMPS	≤200 SEC	0018	#1/0 AWG	XFN0088A-AH/AB CHARCOAL CLEANUP UNIT FAN A	
XMC1A3X	11AC	X		X		SQUARE D FAL36015-13M	225 AMPS	N/A	0053	#4 AWG	XPP0140-SW/DHP1 COOLING UNIT BOOSTER PUMP	
XMC1A3X	11AC		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0053	#4 AWG	XPP0140-SW/DHP1 COOLING UNIT BOOSTER PUMP	
XMC1A3X	11EH	X		X		SQUARE D FAL36050-16M	750 AMPS	N/A	0053	#1/0 AWG	XFN0086A-AH/ SECONDARY COMPT (LOOP A) COOLING FAN A	
XMC1A3X	11EH		X	X		SQUARE D 1FL34050	150 AMPS	≤200 SEC	0053	#1/0 AWG	XFN0086A-AH/ SECONDARY COMPT (LOOP A) COOLING FAN A	
XMC1B2X	3AE	X		X		SQUARE D FAL36015-13M	225 AMPS	N/A	0033	#4 AWG	XVC0503-CC/NOT GATE EXCESS LETDOWN HX	
XMC1B2X	3AE		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0033	#4 AWG	XVC0503-CC/NOT GATE EXCESS LETDOWN HX	
XMC1B2X	5IB	X		X		SQUARE D FAL36015-13M	225 AMPS	N/A	0033	#4 AWG	XVC0578-CC/NOT, ISOLATION RCDT	
XMC1B3X	6IB		X	X		SQUARE D 1FL34020	80 AMPS	≤100 SEC	0033	#4 AWG	XVC0578-CC/NOT, ISOLATION RCDT	
XMC1B3X	3EH	X		X		SQUARE D FAL34015-13M	225 AMPS	N/A	0018	#4 AWG	XPP0059B-WD/ INCORE INSTR CHASE SUMP PUMP B	
XMC1B3X	3EH		X	X		SQUARE D 1FL34015	45 AMPS	≤100 SEC	0018	#4 AWG	XPP0059B-WD/ INCORE INSTR CHASE SUMP PUMP B	

NOTES:-

1. REFER TO E/C DRAWING SS-203-877 FOR 480V AC LOAD CENTER BREAKER TRIP DEVICE TYPE AND ASSOCIATED RELAY SETTINGS.

AMENDMENT 00-01
DECEMBER 2000

NUCLEAR SAFETY RELATED

FSAR Figure 8D-2

DRAWING LEGIBILITY CLASS 2

SCE&G CAD ENHANCED

SOUTH CAROLINA ELECTRIC & GAS COMPANY

VIRGIL C. SUMMER NUCLEAR STATION

ELECTRICAL CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTION DEVICES

DESIGN ENGINEERING

JMR | MCR | DKW

E-224-532 | 2 | 3

3 | [illegible] | REVISED PER [illegible] | MCR | DKW

REVISION

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MISCELLANEOUS PANELS – FUSES (AC)

OVERCURRENT PROTECTION DEVICE – LOCATION – PARENT DEVICE NO.	UNIT NO. OR TAG NO.	APPLICATION – PRI	BACK-UP	CLASS I	CLASS II	TYPE	TEST SET POINT	RESPONSE TIME	PENETRATION – NO. XRP	CONDUCTOR SIZE	LOAD EQUIPMENT NO. – SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
[illegible]	FU25		X	X		BUSS [illegible]-15	≥6.47 BILLIONS	N/A	[illegible]	#4 AWG	[illegible] TRANSFORMER PUBLIC SUPPLY CABINET 3	[illegible]
[illegible]	[illegible]	X		X		BUSS FNM-[illegible]	≥[illegible] BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X	X		BUSS FNM-[illegible]	≥[illegible] BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU	X		X		GOULD SHAWMUT [illegible]	≥6.29 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS FRN-[illegible]	≥19.35 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X			X	BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X			X	BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		GOULD SHAWMUT OT-6	≥20.2 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	FU-[illegible]	X			X	BUSS [illegible]-3	≥47.7 BILLIONS	N/A	[illegible] [illegible]	#12 AWG	120V CONTROL	[illegible] [illegible]
[illegible]	FU-[illegible]	X		X		BUSS FRN-1.2	≥105.0 BILLIONS	N/A	[illegible] [illegible]	#12 AWG	120V CONTROL	[illegible] [illegible] [illegible]

MISCELLANEOUS PANELS – FUSES (AC)

OVERCURRENT PROTECTION DEVICE – LOCATION – PARENT DEVICE NO.	UNIT NO. OR TAG NO.	APPLICATION – PRI	BACK-UP	CLASS I	CLASS II	TYPE	TEST SET POINT	RESPONSE TIME	PENETRATION – NO. XRP	CONDUCTOR SIZE	LOAD EQUIPMENT NO. – SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
[illegible]	[illegible]	X		X		LITTELFUSE [illegible]	≥27.07 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X		X		LITTELFUSE [illegible]	≥[illegible] BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X	X		BUSS [illegible]	≥5.92 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X	X		BUSS [illegible]	≥5.92 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X		X		BUSS [illegible]	≥5.92 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X	X		BUSS [illegible]	≥5.92 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	1FU	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	FHF22X
[illegible]	2FU		X	X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	FHF22X
[illegible]	1FU	X		X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	FHF21X
[illegible]	2FU		X	X		BUSS NON-6	≥19.12 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	FHF21X
[illegible]	[illegible]	X		X		GOULD SHAWMUT [illegible]	≥6.01 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X	X		GOULD SHAWMUT [illegible]	≥6.34 BILLIONS	N/A	[illegible]	#4 AWG	[illegible]	[illegible]
[illegible]	[illegible]		X	X		GOULD SHAWMUT [illegible]	≥6.34 BILLIONS	N/A	[illegible]	#4 AWG	[illegible]	[illegible]
[illegible]	[illegible]		X	X		GOULD SHAWMUT [illegible]	≥4.53 BILLIONS	N/A	[illegible]	#12 AWG	LOOP A REACTOR BUILDING SMOKE DETECTION	[illegible]
[illegible]	[illegible]		X	X		GOULD SHAWMUT [illegible]	≥4.53 BILLIONS	N/A	[illegible]	#12 AWG	LOOP B REACTOR BUILDING SMOKE DETECTION	[illegible]
[illegible]	[illegible]		X	X		GOULD SHAWMUT [illegible]	≥4.53 BILLIONS	N/A	[illegible]	#12 AWG	LOOP C AND D REACTOR BUILDING SMOKE DETECTION	[illegible]
[illegible]	[illegible]		X	X		GOULD SHAWMUT [illegible]	≥9.433 BILLIONS	N/A	[illegible]	[illegible]	[illegible]	[illegible]

MISCELLANEOUS PANELS – FUSES (AC)

OVERCURRENT PROTECTION DEVICE – LOCATION – PARENT DEVICE NO.	UNIT NO. OR TAG NO.	APPLICATION – PRI	BACK-UP	CLASS I	CLASS II	TYPE	TEST SET POINT	RESPONSE TIME	PENETRATION – NO. XRP	CONDUCTOR SIZE	LOAD EQUIPMENT NO. – SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
[illegible]	[illegible]		X		X	BUSS [illegible]	≥15.03 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X		X	BUSS [illegible]	≥15.03 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X			X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X			X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X			X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X		X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X		X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X		X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X			X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X		X	BUSS [illegible]	≥5.97 BILLIONS	N/A	[illegible]	#16 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X		X		BUSS ABC-3	≥43.38 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X	X		BUSS [illegible]	≥9.92 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]	X		X		BUSS ABC-3	≥43.38 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]
[illegible]	[illegible]		X	X		BUSS [illegible]	≥9.92 BILLIONS	N/A	[illegible]	#12 AWG	120V CONTROL	[illegible]

NUCLEAR SAFETY RELATED

AMENDMENT 00-01
DECEMBER 2000

DRAWING LEGIBILITY CLASS 2
SCE&G CAD ENHANCED

4	[illegible]	TGB	REVISED PER ECR-50084	MCR	RAT
NO.	DATE	BY	REVISION	CHD. BY	LC APPROVAL

FSAR Figure 8G-5

SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
ELECTRICAL
CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTION DEVICES
DESIGN ENGINEERING
V. C. SUMMER NUCLEAR STATION JENKINSVILLE S.C.

TGB | MCR | RAT

E-224-532 | 5 | 4

1/4" = 1'-0" 0 5' 10' 15' 20'

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MISCELLANEOUS PANELS - FUSES (DC)

OVERCURRENT PROTECTION DEVICE									PENETRATION		LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS
LOCATION		APPLICATION		CLASS								
PARENT DEVICE NO.	UNIT NO. OR TAG NO.	PRI	BACK-UP	I	A X P	TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP	CONDUCTOR SIZE		
XCA29-CR	A61-FU51	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0025	#1/0 AWG	SHUTDOWN BANK A GROUP 2 MECHANISM 3	CRDM-H3 125V DC
XCA29-CR	A61-FU52	X			X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0026	#1/0 AWG	SHUTDOWN BANK A GROUP 2 MECHANISM 4	CRDM-J3 125V DC
XCA29-CR	A51-FU1	X			X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 1	CRDM-C6 125V DC
XCA29-CR	A51-FU2	X			X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 2	CRDM-F12 125V DC
XCA29-CR	A52-FU1	X			X	GOULD SHAWMUT A25353-4	≥1.71 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 3	CRDM-M10 125V DC
XCA29-CR	A52-FU2	X			X	GOULD SHAWMUT A25353-4	≥1.71 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 4	CRDM-L4 125V DC
XCA29-CR	A53-FU1	X			X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 1	CRDM-F6 125V DC
XCA29-CR	A53-FU2	X			X	GOULD SHAWMUT A25353-4	≥1.71 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 2	CRDM-F10 125V DC
XCA29-CR	A54-FU1	X			X	GOULD SHAWMUT A25353-4	≥1.71 MILLIOHMS	N/A	0056	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 3	CRDM-K10 125V DC
XCA29-CR	A54-FU2	X			X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0056	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 4	CRDM-K6 125V DC
XCA29-CR	A55-FU1	X			X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 1	CRDM-C3 125V DC
XCA29-CR	A55-FU2	X			X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 2	CRDM-C9 125V DC
XCA29-CR	A56-FU1	X			X	GOULD SHAWMUT A25353-4	≥1.71 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 3	CRDM-J9 125V DC
XCA29-CR	A56-FU2	X			X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 4	CRDM-J7 125V DC
XCA29-CR	A57-FU1		X		X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0055 0056	#1/0 AWG	CONTROL BANK B,D SHUTDOWN BANK B GROUP 2 MECHANISM 1	CRDM-B8,F8,C7 125V DC
XCA29-CR	A57-FU2		X		X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0055 0058	#1/0 AWG	CONTROL BANK B,D SHUTDOWN BANK B GROUP 2 MECHANISM 2	CRDM-F12,F10,G8 125V DC
XCA29-CR	A58-FU1		X		X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0055 0056	#1/0 AWG	CONTROL BANK B,D SHUTDOWN BANK B GROUP 2 MECHANISM 3	CRDM-M10,K10,J9 125V DC
XCA29-CR	A58-FU2		X		X	GOULD SHAWMUT A25350-4	≥1.71 MILLIOHMS	N/A	0055 0058	#1/0 AWG	CONTROL BANK B,D SHUTDOWN BANK B GROUP 2 MECHANISM 4	CRDM-K4,K6,J7 125V DC
XCA29-CR	A59-FU13	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 1	CRDM-C6 125V DC
XCA29-CR	A59-FU14	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 2	CRDM-F12 125V DC
XCA29-CR	A59-FU15	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 3	CRDM-M10 125V DC
XCA29-CR	A59-FU16	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 4	CRDM-K4 125V DC
XCA29-CR	A59-FU17		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 1	CRDM-D6 125V DC
XCA29-CR	A59-FU18		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 2	CRDM-F12 125V DC
XCA29-CR	A59-FU19		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 3	CRDM-M10 125V DC
XCA29-CR	A59-FU20		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 4	CRDM-K4 125V DC
XCA29-CR	A59-FU21	X			X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 1	CRDM-D6 125V DC
XCA29-CR	A59-FU22	X			X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 2	CRDM-F12 125V DC
XCA29-CR	A59-FU23	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 3	CRDM-M10 125V DC
XCA29-CR	A59-FU24	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 4	CRDM-K4 125V DC
XCA29-CR	A60-FU25	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 1	CRDM-F6 125V DC
XCA29-CR	A60-FU26	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 2	CRDM-F10 125V DC
XCA29-CR	A60-FU27	X			X	BUSS P/N 2432853	≥37.5 MILLIOHMS	N/A	0056	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 3	CRDM-K10 125V DC
XCA29-CR	A60-FU28	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0056	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 4	CRDM-K6 125V DC
XCA29-CR	A60-FU29		X		X	BUSS P/N 2432856	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 1	CRDM-F6 125V DC

MISCELLANEOUS PANELS - FUSES (DC)

OVERCURRENT PROTECTION DEVICE									PENETRATION		LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS
LOCATION		APPLICATION		CLASS								
PARENT DEVICE NO.	UNIT NO. OR TAG NO.	PRI	BACK-UP	I	A X P	TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP	CONDUCTOR SIZE		
XCA29-CR	A60-FU31		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 2	CRDM-F12 125V DC
XCA29-CR	A60-FU32		X		X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0056	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 3	CRDM-K10 125V DC
XCA29-CR	A60-FU33		X		X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK D GROUP 2 MECHANISM 4	CRDM-K6 125V DC
XCA29-CR	A60-FU34	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 1	CRDM-F6 125V DC
XCA29-CR	A60-FU35	X			X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0055	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 2	CRDM-F10 125V DC
XCA29-CR	A60-FU36	X			X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0056	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 3	CRDM-K10 125V DC
XCA29-CR	A60-FU37		X		X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0056	#1/0 AWG	CONTROL BANK B GROUP 2 MECHANISM 4	CRDM-K6 125V DC
XCA29-CR	A60-FU38		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 1	CRDM-C3 125V DC
XCA29-CR	A60-FU39		X		X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 2	CRDM-C9 125V DC
XCA29-CR	A60-FU40		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 3	CRDM-J9 125V DC
XCA29-CR	A60-FU41		X		X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 4	CRDM-J7 125V DC
XCA29-CR	A61-FU41	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 1	CRDM-C3 125V DC
XCA29-CR	A61-FU42	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 2	CRDM-C9 125V DC
XCA29-CR	A61-FU43	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 3	CRDM-J9 125V DC
XCA29-CR	A61-FU44	X			X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 4	CRDM-J7 125V DC
XCA29-CR	A61-FU45		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055 0055	#1/0 AWG	CONTROL BANK B,D SHUTDOWN BANK B GROUP 2 MECHANISM 1	CRDM-C6,F6,G7 125V DC
XCA29-CR	A61-FU46		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055 0056	#1/0 AWG	CONTROL BANK B,D SHUTDOWN BANK B GROUP 2 MECHANISM 2	CRDM-F12,F10,G8 125V DC
XCA29-CR	A61-FU47		X		X	BUSS P/N 2432858	≥37.5 MILLIOHMS	N/A	0055 0056	#1/0 AWG	CONTROL BANK B,D SHUTDOWN BANK B GROUP 2 MECHANISM 3	CRDM-M10,K10,J9 125V DC
XCA29-CR	A61-FU48		X		X	BUSS P/N 2432859	≥37.5 MILLIOHMS	N/A	0055 0056	#1/0 AWG	CONTROL BANK B,C SHUTDOWN BANK B GROUP 2 MECHANISM 4	CRDM-K4,K6,J7 125V DC
XCA29-CR	A61-FU49	X			X	BUSS P/N 2432853	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 1	CRDM-G7 125V DC
XCA29-CR	A61-FU50	X			X	BUSS P/N 2432853	≥37.5 MILLIOHMS	N/A	0056	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 2	CRDM-G9 125V DC
XCA29-CR	A61-FU53	X			X	BUSS P/N 2432853	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 3	CRDM-F3 125V DC
XCA29-CR	A61-FU57	X			X	BUSS P/N 2432853	≥37.5 MILLIOHMS	N/A	0058	#1/0 AWG	SHUTDOWN BANK B GROUP 2 MECHANISM 4	CRDM-J7 125V DC
XCP6101-BC (XCP6100 SUBPNL 1)	FU-RR25	X	X		X	GOULD SHAWMUT OT-4	≥20.2 MILLIOHMS	N/A	0029	#12 AWG	125V CONTROL	OUTBOARD CIRCUIT NO. XRR25A
XCP6101-BC (XCP6100 SUBPNL 1)	FU-RR27	X	X		X	GOULD SHAWMUT OT-4	≥20.2 MILLIOHMS	N/A	0029	#12 AWG	125V CONTROL	OUTBOARD CIRCUIT NO. XRR27A
XCP6101-BC (XCP6100 SUBPNL 1)	FU-RR28	X	X		X	BUSS NON-6	≥19.12 MILLIOHMS	N/A	0026	#12 AWG	125V CONTROL	OUTBOARD CIRCUIT NO. XRR28A

MISCELLANEOUS PANELS - FUSES (DC)

OVERCURRENT PROTECTION DEVICE									PENETRATION		LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
LOCATION		APPLICATION		CLASS								
PARENT DEVICE NO.	UNIT NO. OR TAG NO.	PRI	BACK-UP	I	A X P	TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP	CONDUCTOR SIZE		
XCP6132-BC (XCP6100 SUBPNL 1)	FU-SS01	X	X		X	GOULD SHAWMUT OT-8	≥23.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	SSX2A SSY2A
XCP6132-BC (XCP6100 SUBPNL 1)	FU-SS33	X	X		X	GOULD SHAWMUT OT-8	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	SSX27A SSY27A
XCP6132-BC (XCP6133 SUBPNL 1)	FU-SS07	X	X		X	GOULD SHAWMUT OT-8	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	SS043A
XCP6102-BC (XCP6100 SUBPNL 1)	FU-SS08	X	X		X	GOULD SHAWMUT OT-10	≥14.07 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	SSX53A
XCP6102-BC (XCP6100 SUBPNL 1)	FU-SS10	X	X		X	GOULD SHAWMUT OT-8	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	SSY33A
XCP6102-BC (XCP6100 SUBPNL 1)	FU-SS11	X	X		X	GOULD SHAWMUT OT-3	≥[illegible] MILLIOHMS @ 25°C	N/A	0028	#12 AWG	125V CONTROL	SSX83A
XCP6134-BC (XCP6100 SUBPNL 2)	FU-RR2E	X	X		X	BUSS NON-6	≥19.12 MILLIOHMS	N/A	0030	#12 AWG	125V CONTROL	RRX11B
XCP6134-BC (XCP6130 SUBPNL 2)	FU-IX51	X	X		X	GOULD SHAWMUT OT-8	≥20.2 MILLIOHMS	N/A	0030	#12 AWG	125V CONTROL	IAV13B
XCP6134-BC (XCP6100 SUBPNL 2)	FU-SS44	X	X		X	GOULD SHAWMUT OT-8	≥20.2 MILLIOHMS	N/A	0030	#12 AWG	125V CONTROL	SSX184B
XCP6106-BC (XCP6100 SUBPNL 3)	FU-RR50	X	X		X	BUSS NON-2	≥ 76.7 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	RCV1A
XCP6106-BC (XCP6130 SUBPNL 3)	FU-S115	X	X		X	BUSS NON-1½	≥ 126.6 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	SIB1A

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FSAR Figure 8G-8

[illegible]
VIRGIL C. SUMMER NUCLEAR STATION
[illegible]

NO.	DATE	BY	REVISION	CHK'D BY	APPROVAL
5	5/20/00	RHM	REVISED PER CGSS-99-0311	MCR	SGS
4	1/29/00	DOJ	REVISED PER ECR-50144	RHM	GJR

DOJ | RHM | GJR
E-224-532 | 8 | 5

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MISCELLANEOUS PANELS - FUSES (DC)

PARENT DEVICE NO. (LOCATION)	UNIT NO. OR TAG NO. (LOCATION)	PRI (APPLICATION)	BACK-UP (APPLICATION)	CLASS		TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP (PENETRATION)	CONDUCTOR SIZE (PENETRATION)	LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
XCP6107-NC (XCP6103 SUBPNL 3)	FU-C333A	X	X		X	BUSS [illegible]	≥ [illegible] MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CSV513A
XCP6107-NC (XCP6103 SUBPNL 3)	FU-C160A	X	X		X	BUSS [illegible]	≥ [illegible] MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CSV713A
XCP6107-NC (XCP6100 SUBPNL 3)	FU-C301	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CSV1013A
XCP6107-NC (XCP6103 SUBPNL 3)	FU-C302	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CSV1313A
XCP6107-NC (XCP610C SUBPNL 3)	FU-C333A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CSV2013A
XCP6107-NC (XCP6100 SUBPNL 3)	FU-C334A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CSV2113A
XCP6107-NC (XCP6100 SUBPNL 3)	FU-C335A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CSV2213A
XCP6107-NC (XCP6100 SUBPNL 3)	FU-RC31	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	RC300A
XCP6107-NC (XCP610C SUBPNL 3)	FU-RC32	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	RC301A
XCP6107-NC (XCP610C SUBPNL 3)	FU-RC36	X	X		X	BUSS [illegible]	≥ [illegible] MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	RC351A
[illegible] (SUBPNL 4)	[illegible]	X	X		X	BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 4)	[illegible]	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 4)	[illegible]	X	X	X		BUSS [illegible]	≥ [illegible] MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 4)	[illegible]	X	X		X	BUSS [illegible]	≥ [illegible] MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 3)	[illegible]	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 4)	[illegible]	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 3)	[illegible]	X	X		X	BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 4)	[illegible]	X	X		X	BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 4)	[illegible]	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 5)	[illegible]	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 5)	[illegible]	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 5)	[illegible]	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 5)	[illegible]	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 4)	[illegible]	X	X	X		BUSS [illegible]	≥ [illegible] MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 5)	[illegible]	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible] (SUBPNL 5)	[illegible]	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]

MISCELLANEOUS PANELS - FUSES (DC)

PARENT DEVICE NO. (LOCATION)	UNIT NO. OR TAG NO. (LOCATION)	PRI (APPLICATION)	BACK-UP (APPLICATION)	CLASS		TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP (PENETRATION)	CONDUCTOR SIZE (PENETRATION)	LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
XCP6109-NC (XCP6100 SUBPNL 5)	FU-RC54	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0034	#12 AWG	125V CONTROL	RC951X
XCP6109-NC (XCP610C SUBPNL 5)	FU-RC55	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	0034	#12 AWG	125V CONTROL	RC981X
XCP6109-NC (XCP6109 SUBPNL 5)	FU-RC56	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0034	#12 AWG	125V CONTROL	RC971X
XCP6109-NC (XCP6100 SUBPNL 5)	FU-S160	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1924X
XCP6109-NC (XCP610C SUBPNL 5)	FU-S161	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1925X
XCP6109-NC (XCP6108 SUBPNL 5)	FU-S162	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1934X
XCP6109-NC (XCP6103 SUBPNL 5)	FU-S163	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1935X
XCP6109-NC (XCP610C SUBPNL 5)	FU-S164	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1944X
XCP6109-NC (XCP6105 SUBPNL 5)	FU-S165	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1945X
XCP6109-NC (XCP6106 SUBPNL 5)	FU-S166	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1954X
XCP6109-NC (XCP6101 SUBPNL 5)	FU-S167	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1955X
XCP6109-NC (XCP610C SUBPNL 5)	FU-S168	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1964X
XCP6109-NC (XCP6103 SUBPNL 5)	FU-S169	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1965X
XCP6109-NC (XCP6100 SUBPNL 5)	FU-S170	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1974X
XCP6109-NC (XCP6100 SUBPNL 5)	FU-S171	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	S1975X
XCP6110-NC (XCP6104 SUBPNL 7)	[illegible]	X	X	X		BUSS [illegible]	≥ [illegible] MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
XCP6110-NC (XCP6104 SUBPNL 7)	[illegible]	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
XCP6112-NC (XCP6103 SUBPNL 5)	[illegible]	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0033	#12 AWG	125V CONTROL	[illegible]

MISCELLANEOUS PANELS - FUSES (DC)

PARENT DEVICE NO. (LOCATION)	UNIT NO. OR TAG NO. (LOCATION)	PRI (APPLICATION)	BACK-UP (APPLICATION)	CLASS		TYPE	TEST SET POINT	RESPONSE TIME	NO. XRP (PENETRATION)	CONDUCTOR SIZE (PENETRATION)	LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
[illegible]	[illegible]	X	X	X		BUSS FRN-R	≥9.35 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X		X	BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X		X	BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	[illegible]	X	X		X	BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	LF-2	X	X	X		BUSS FRN-R 2	≥5 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	LF-3	X	X	X		BUSS FRN-R 2	≥5 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	LF-4	X	X	X		BUSS FRN-R 2	≥5 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	LF-5	X	X	X		BUSS FRN-R 2	≥5 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F01	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F02	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F03	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F04	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F05	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F06	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F07	X	X	X		GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F08	X	X	X		BUSS NON-6	≥10.12 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]
[illegible]	F09	X	X	X		BUSS FRN-R	≥25.35 MILLIOHMS	N/A	[illegible]	#12 AWG	125V CONTROL	[illegible]

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NUCLEAR SAFETY RELATED

FSAR Figure 8G-9

DDJ RHM CJR

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MISCELLANEOUS PANELS-FUSES (DC)

OVERCURRENT PROTECTION DEVICE – LOCATION – PARENT DEVICE NO.	UNIT NO. OR TAG NO.	APPLICATION – PRI	BACK-UP	CLASS I	CLASS II	TYPE	TEST SET POINT	RESPONSE TIME	PENETRATION – NO. XRP	CONDUCTOR SIZE	LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS (OUTBOARD CKT NO.)
XPN0282	FU1		X	X		GOULD SHAWMUT A3T3C-1	≥1.70 MILLIOHMS	N/A	0053	#1/0 AWG	XPN0007C-EI EMERGENCY LIGHTING PANEL	125V DC
XPN5494-AN	FU1, 2	X	X		X	GOULD SHAWMUT TRS150R	≥.855 MILLIOHMS	N/A	0011	250 MCM	ECB ON RBCU MOT XFN0038A	-48V DC
XPN5494-AN	FU3, 4	X	X		X	GOULD SHAWMUT TRS150R	≥.855 MILLIOHMS	N/A	0010	250 MCM	ECB ON RBCU MOT XFN0038C	-48V DC
XPN5495	FU1, 2	X	X		X	GOULD SHAWMUT TRS150R	≥.855 MILLIOHMS	N/A	0007	250 MCM	ECB ON RBCU MOT XFN0038B	-48V DC
XPN5495	FU3, 4	X	X		X	GOULD SHAWMUT TRS150R	≥.855 MILLIOHMS	N/A	0014	250 MCM	ECB ON RBCU MOT XFN0038D	-48V DC
XPN5517-PS	FU1		X	X		GOULD SHAWMUT A2Y15-1	≥8.81 MILLIOHMS	N/A	RB302 CONAX	#14 AWG	RB303-PS PERSONNEL AIRLOCK	PS83X
XPN5517-PS	FU2		X	X		GOULD SHAWMUT A2Y15-1	≥8.81 MILLIOHMS	N/A	RB202 CONAX	#14 AWG	RB202-PS PERSONNEL AIRLOCK	PS84X
XPN7834-SG	FU41	X	X		X	BUSS ABC-6	≥21.77 MILLIOHMS	N/A	0023	#12 AWG	125V CONTROL	CS148A
XPN7834-SG	FU43	X	X		X	BUSS ABC-6	≥21.77 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS158A
XPN7834-SG	FU45	X			X	BUSS ABC-6	≥21.77 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS168A
XPN7834-SG	FU49		X		X	BUSS ABC-6	≥21.77 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS165A
XPN7200A-CE	FU-CS58A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0024	#12 AWG	125V CONTROL	CS581XA
XPN7200A-CE	FU-CS62A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS721XA
XPN7200A-CE	FU-CS83A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS4201XA
XPN7200A-CE	FU-CS13C	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS143A
XPN7200A-CE	FU-CS64A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS721XA
XPN7200A-CE	FU-CS64C	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS129A
XPN7200A-CE	FU-CS63A	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS2213A
XPN7200A-CE	FU-CS65C	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	CS185A
XPN7200A-CE	FU-RC51	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0028	#12 AWG	125V CONTROL	RC433A
XPN7200B-CE	FU-RC53	X	X		X	GOULD SHAWMUT OT-6	≥20.2 MILLIOHMS	N/A	0030	#12 AWG	125V CONTROL	RC426B

MISCELLANEOUS PANELS-FUSES (DC)

OVERCURRENT PROTECTION DEVICE – LOCATION – PARENT DEVICE NO.	UNIT NO. OR TAG NO.	APPLICATION – PRI	BACK-UP	CLASS I	CLASS II	TYPE	TEST SET POINT	RESPONSE TIME	PENETRATION – NO. XRP	CONDUCTOR SIZE	LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS
XPN5333-AN DSV-A	FU1 FU2	X	X	X		BUSS FRN-R60	≥1.0 MILLIOHMS	N/A	0011	250 MCM	ECB ON CRDM COOLING SYSTEM FAN XFN67A	-6V DC
XPN5333-AN DSV-B	FU1 FU2	X	X	X		BUSS FRN-R60	≥1.0 MILLIOHMS	N/A	0010	250 MCM	ECB ON CRDM COOLING SYSTEM FAN XFN67B	-6V DC
XPN5333-AN DSV-C	FU1 FU2	X	X	X		BUSS FRN-R60	≥1.0 MILLIOHMS	N/A	0019	250 MCM	ECB ON CRDM COOLING SYSTEM FAN XFN67C	-6V DC
XPN5333-AN DSV-D	FU1 FU2	X	X	X		BUSS FRN-R60	≥1.0 MILLIOHMS	N/A	0018	250 MCM	ECB ON CRDM COOLING SYSTEM FAN XFN67D	-6V DC

OVERCURRENT PROTECTION DEVICE – LOCATION – PARENT DEVICE NO.	UNIT NO. OR TAG NO.	APPLICATION – PRI	BACK-UP	CLASS I	CLASS II	TYPE	TEST SET POINT	RESPONSE TIME	PENETRATION – NO. XRP	CONDUCTOR SIZE	LOAD EQUIPMENT NO. - SYSTEM DESCRIPTION	REMARKS

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NUCLEAR SAFETY RELATED

DRAWING LEGIBILITY CLASS 2
SCE&G CAD ENHANCED

FSAR Figure 8G-10
SOUTH CAROLINA ELECTRIC & GAS COMPANY
VIRGIL C. SUMMER NUCLEAR STATION
ELECTRICAL
CONTAINMENT PENETRATION CONDUCTOR
OVERCURRENT PROTECTION DEVICES
DESIGN ENGINEERING

NO.	DATE	BY	REVISION	CHK. BY	LE APPROVAL
2	9/13/99	JMR	REVISED PER CGSS-99-0489	MGR	DKW

JMR | MGR | DKW

E-224-532 | 10 | 2

1/4" = 1'-0" 0' 5' 10' 15' 20'

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