TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 7. INSTRUMENTATION AND CONTROL

7.1 INTRODUCTION

Instrumentation and control systems include the Reactor Protective System, the Engineered Safeguards Protective Systems, the Rod Drive Control System, the Integrated Control System, the Nuclear Instrumentation System, the Non-Nuclear Instrumentation System, and the Incore Monitoring System.

7.1.1 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

The protective systems, which consist of the Reactor Protective System and the Engineered Safeguards Protective Systems, perform important control and safety functions. The protective systems extend from the sensing instruments to the final actuating devices, such as circuit breakers and pump or valve motor contactors.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

7.1.2.1 Design Bases

The protective systems are designed to sense plant parameters and actuate emergency actions in the event of abnormal plant parameter values. They meet the intent of the Proposed IEEE "Criteria for Nuclear
9 Power Plant Protection Systems" dated August, 1968. (IEEE No. 279). Protective system equipment
9 located in the Control Room, Cable Room, and Aux Building is designed for a mild environment, not
9 LOCA conditions (i.e. 59 psig, 273°F).

7.1.2.2 Single Failure

The protective options meet the single failure criterion of IEEE No. 279 to the extent that:

1. No single component failure will prevent a protective system from fulfilling its protective functions when action is required.
2. No single component failure will initiate unnecessary protective system action where implementation does not conflict with the criterion above.

7.1.2.3 Redundancy

All Reactor Protective System functions are implemented by redundant sensors, measuring channels, logic, and actuation devices. These elements combine to form the protective channels.

7.1.2.4 Independence

Redundant protective channels are electrically independent and are packaged to provide physical separation.

7.1.2.5 Separation

Protective channels are physically separate and are electrically isolated from regulating instrumentation. Only one string of instrumentation may be selected at a given time for use in a system control function,
7 and electrical isolation is assured through the use of appropriate isolation devices. A fifth channel of
7 regulating instrumentation not associated with protection is employed for additional control purposes.

7.1.2.6 Manual Trip

Manual trip switches, independent of the automatic trip instrumentation, are provided.

7.1.2.7 Testing

Manual testing facilities are built into the protective systems to provide for:

1. Preoperational testing to give assurance that a protective system can fulfill its required protective functions.
2. On-line testing to prove operability and to demonstrate reliability.

5 3. BWNT STAR module provides both manual and automated test capability, and self diagnostic tests
5 performed during start-up and operation. The front panel of the STAR module has LED indicators
5 which indicate module status.

7.1.3 IDENTIFICATION OF PROTECTIVE EQUIPMENT

All safety related sensors, transmitters, transducers, cabinets, etc. located outside the control room are physically identified by placement of a permanent, conspicuous tag on or adjacent to the device. A typical tag bears the wording "Safety Related." The following are examples of equipment that should be tagged:

Swgr 1TC
LD Ctr lX8
MCC lXSl
ESG channel 1, 3, 5, & 7
DC Pnlbd 1DIA
Vital Pwr Pnlbd 1KVIA
RPS Ch A

Swgr 1TD
LD Ctr 1X9
MCC 1XS2
ESG channel 2, 4, 6, & 8
DC Pnlbd 1DIB
Vital Pwr Pnlbd 1KVIB
RPS Ch B

Swgr 1TE
MCC lXS3
DC Pnlbd 1DIC

Vital Pwr Pnlbd 1KVIC

RPS Ch C

ESG Channel Even-Odd

DC Pnlbd 1DID

Vital Pwr Pnlbd 1KVID

RPS Ch D

7.2 REACTOR PROTECTIVE SYSTEM

0 **Note**

0 This section of the FSAR contains information on the design bases and design criteria of this
0 system/structure. Additional information that may assist the reader in understanding the system is
0 contained in the design basis document (DBD) for this system/structure.

The Reactor Protective System (RPS) monitors parameters related to safe operation and trips the reactor to protect the reactor core against fuel rod cladding damage. It also assists in protecting against Reactor Coolant System damage caused by high system pressure by limiting energy input to the system through reactor trip action.

7.2.1 DESIGN BASES

The Reactor Protective System includes all design basis features of Section 7.1.2, "Identification of Safety Criteria" with the following additions:

7.2.1.1 Loss of Power

A loss of power to a reactor protective channel will cause that protective channel to trip.

7.2.1.2 Equipment Removal

The Reactor Protective System initiates a protective channel trip whenever a module or subassembly is removed from the equipment cabinet. Removing a reactor trip module causes the associated control rod breaker to trip.

7.2.1.3 Diverse Means of Reactor Trip

In the unlikely event of a systematic or complete failure of the Reactor Coolant System low pressure signals to trip the reactor following the initiation of emergency core cooling, there is a separate, diverse means of assuring reactor trip. A high pressure in the Reactor Building is independently sensed by four sensors, and independent signals are fed from these sensors to the four Reactor Protective System channels to provide the desired diverse reactor trip signal.

7.2.2 SYSTEM DESIGN

7.2.2.1 System Logic

The system as shown in Figure 7-1 consists of four identical protective channels, each terminating in a trip relay within a reactor trip (RT) Module. In the normal untripped state, each protective channel functions as an AND gate, passing current to the terminating relay and holding it energized as long as all inputs are in the normal energized (untripped) state. Should any one or more inputs become de-energized (tripped), the terminating relay in that protective channel becomes an OR gate.

Each of the four protective channels terminates in a channel trip relay within a reactor trip module. There are four such modules. Each protective channel trip relay has four contacts, each controlling a logic relay in one reactor trip module. Therefore, each reactor trip module has four logic relays controlled by the four protective channels. The four logic relays combine to form a 2-out-of-4 coincidence network in each reactor trip module. The coincidence logics in all reactor trip modules trip whenever any two of the four protective channels trip.

The reactor trip modules are given the same designation as the protective channel whose trip relay they contain and in whose cabinet they are physically located. Thus, the protective channel A reactor trip module is located in protective channel A cabinet, etc. (Figure 7-1). The coincidence logic in each reactor trip module controls one or more breakers in the control rod drive power system.

The coincidence logic contained in the Reactor Protective System channel A RT module controls breaker A in the Control Rod Drive System as shown in Figure 7-1, channel B RT module controls breaker B, channel C RT module controls breakers C and E, and channel D RT module controls breakers D and F. Breakers A and B control all the 3 phase primary power to the rod drives; breakers C and D control the DC power to rod groups 1 through 4; and breakers E and F control the gating power to rod groups 5 through 8 and the auxiliary power supplies. The control rod drive circuit breaker combinations that initiate a reactor trip can best be stated in logic notation as: AB + ADF + BCE + CDEF. This is a 1-out-of-2 logic used twice and is referred to as a 1-out-of-2 × 2 logic. It should be noted that when any 2-out-of-4 protective channels trip, all reactor trip module logics trip, commanding all control rod drive breakers to trip.

The undervoltage coils of the control rod drive breakers receive their power from the protective channel associated with each breaker. The manual reactor trip switch is interposed in series between each RT module logic and the assigned breakers undervoltage coil.

In response to NRC Generic Letter 83-28 automatic actuation of the AC and DC breaker shunt trip attachments for the Reactor Trip System and Manual Trip Actuation have been installed. This upgrade improves the reactor trip breaker reliability.

For the reactor trip breakers in each channel a relay is installed with its operating coil in parallel with the existing undervoltage device. The output contacts of these relays controls the power to the shunt trip devices. Thus, when power is removed from the breaker undervoltage trip attachment on either a manual or automatic trip signal, the shunt trip attachment is energized to provide an additional means to trip the breaker. Test switches are installed to permit independent testing of the shunt and undervoltage trip devices and silicon controlled rectifiers. Loss of shunt trip control power is annunciated in the control room indicating that the shunt trip device is not operable.

7.2.2.2 Summary of Protective Functions

The four Reactor Protective System protective channels are identical in their functions, which combine in the system logic to trip the reactor automatically and protect the reactor core for the following conditions:

1. When the reactor power, as measured by neutron flux, exceeds a fixed maximum limit.
2. When the reactor power, as measured by neutron flux, exceeds the limit set by the reactor coolant flow and power imbalance.
3. When the reactor power exceeds the limit set by the number and combination of reactor coolant pumps in operation.
4. When the reactor outlet temperature exceeds a fixed maximum limit.
5. When a specified reactor pressure-outlet temperature relationship is exceeded.
6. When the reactor pressure falls below a fixed minimum limit.

7. When Reactor Building pressure exceeds a fixed maximum limit.
6 8. The RPS automatically trips the reactor to protect the Reactor Coolant System whenever the reactor
6 pressure exceeds a fixed maximum limit.
6 9. The RPS automatically trips the reactor upon main turbine trip or trip of both main feedwater
6 pumps.

The abnormal conditions that initiate a reactor trip are keyed to the above listing and tabulated in Table 7-1.

7.2.2.3 Description of Protective Channel Functions

The functions of the RPS described below apply to each protective channel.

7.2.2.3.1 Over Power Trip

The nuclear instrumentation provides a linear neutron flux signal in the power range as an indication of reactor power to a protective system bistable trip module.

When the neutron flux signal exceeds the trip point of the bistable, the bistable trips, de-energizing the associated protective channel trip relay.

7.2.2.3.2 Nuclear Over Power Trip Based on Flow and Imbalance

Neutron flux and the reactor coolant flow are continuously monitored. A linear neutron flux signal is
received from the nuclear instrumentation and a total reactor coolant flow signal is received from the flow
7 tubes. A power level trip setpoint is established for a STAR module as the percentage reactor coolant
flow rate multiplied by the flux to flow ratio. The reactor power imbalance (power in the top half of the
core minus the power in the bottom half of the core) reduces the power level trip setpoint such that the
four pump power-imbalance boundaries illustrated in Figure 7-2 are not exceeded. Less than four pump
power-imbalance protection is provided by the power level trip setpoint decrease due to flow decrease.
When the neutron flux signal exceeds the power level trip setpoint established by the total reactor coolant
7 flow and the reactor power imbalance the STAR module trips, de-energizing the associated protective
channel trip relay.

All flow ΔP cells for a single loop are connected to common 1-inch "low" and "high" lines from the flow tube in that loop. Severance of the "low" line will result in maximum indicated flow for the loop in all four protective channels. All console indicators for the loop will go to 110 percent full flow. Severance of the "high" line will result in zero indicated flow for the loop and possibly a power/flow reactor trip. See Section 7.4.2.3.1, "Failure in RC Flow Tube Instrument Piping" for more details.

6

7.2.2.3.3 Power/Reactor Coolant Pumps Trip

The reactor coolant (RC) pumps are monitored to determine that they are running. Loss of a single
pump initiates four independent signals, one to each protective channel. This information is received by a
pump monitor logic which counts the number of RC pumps in operation and identifies the coolant loop
in which the pumps are operating. The pump monitor logic output controls the trip point of a
power/pump comparator, and initiates a protective channel trip for the conditions in Table 7-1.
6 Normally, the trip point corresponding to only two pumps in operation is set at approximately 2 percent
6 full power. If two pumps are lost, a reactor trip will be initiated.

7.2.2.3.4 Reactor Outlet Temperature Trip

The reactor outlet temperature is measured by resistance elements. The bridge for each resistance element is considered a part of, and is located within, its associated protective system channel cabinet.

The reactor outlet temperature signal from the temperature bridge passes through a signal converter and then is applied to a bistable trip module. When the temperature exceeds the trip point of the bistable, the
4 bistable trips, de-energizing the protective channel trip relay.

7.2.2.3.5 Pressure-Temperature Trip

7 Figure 7-2 shows typical operating reactor coolant pressure-temperature boundaries formed by the combined reactor high temperature, high pressure, low pressure, and the pressure-temperature comparator trip settings. The pressure-temperature comparator trips whenever the specified reactor pressure-outlet
7 temperature relationship is exceeded. The comparator forms the boundary line A-B in Figure 7-2.

7.2.2.3.6 Reactor Coolant Pressure Trip

The reactor coolant pressure signal from the pressure transmitter is received by an isolation module in the associated protective channel cabinet. This module acts as a signal conditioner and isolation unit.

Pressure signals go to a high pressure bistable trip module and a low pressure trip module. When the pressure exceeds the trip point of the high pressure bistable, the bistable trips de-energizing the protective channel trip relay.

The low pressure bistable trips when the pressure falls below the trip point, tripping the protective channel trip relay.

7.2.2.3.7 Main Turbine Trip

Pressure switches monitoring the hydraulic fluid pressure in the Turbine Emergency Trip System header will input an open indication to the RPS on turbine trip. Contact buffers located in each RPS channel provide isolation for the RPS System from the field contacts. Upon sensing field contact change state, the contact buffer will initiate an RPS trip when a turbine trip is indicated. This trip is bypassed below a predetermined flux level for unit startup.

7.2.2.3.8 Loss of Main Feedwater Trip

6 Control oil pressure switches for each feedwater pump will input an open indication to the RPS on feedwater pump trip. Isolation contact buffers in the RPS sense the field contact inputs and initiate an RPS trip when both pumps have tripped. This trip is bypassed below a predetermined flux level for unit startup.

7.2.2.3.9 Reactor Building Pressure Trip

Each of the four protective channels receives Reactor Building pressure information from an independent pressure switch. A contact buffer in each protective channel continuously monitors the state of the associated pressure switch. When the state of the pressure switch changes to that corresponding to a Reactor Building pressure exceeding the trip point specified in Table 7-1, the contact buffer de-energizes the protective channel's trip relay.

7.2.2.4 Setpoint Adjustments for Single Loop Operation

Following amendments 165/165/162 to the facility operating license, single loop power operation is prohibited.

7.2.2.5 Availability of Information

The modules, logic, and analog equipment associated with a single protective channel are contained
5 wholly within two Reactor Protective System cabinets. Within these cabinets, there is a meter for most of
5 the analog signals employed by the protective channel, and a visual indication of the state of every logic
5 element. The exceptions to having local meters for indication of the analog signals are the Units 2 and 3
5 RC flow and flux imbalance signals. This information may be obtained by connecting the calibration test
5 computer to the cabinet hardware. At the top of one cabinet, and easily visible at all times, is a protective channel status panel. Lamps on this panel give a quick visual indication of the trip status of the particular protective channel and of the RT module associated with it. Additional lamps on the panel give visual indication of a channel bypass or a fan failure.

In addition to the visual indications and readouts within the protective channel cabinets, each trip function, power supply, and analog signal is monitored by the plant computer. Separate from the computer, trip actions are sequence-annunciated in the plant status annunciator. Such sequencing permits the operator to identify readily the protective channel trip actions. Process instrumentation including power, imbalance, flow, temperature, and pressure is indicated on the main control console.

Plant annunciator windows provide the operator with immediate indications of changes in the status of the Reactor Protective System. The following conditions are annunciated for each Reactor Protective System channel:

1. channel trip
2. fan failure in channel
3. channel on test
4. shutdown bypass initiated
5. manual bypass initiated
6. dummy bistable installed

Any time a test switch is in other than the operate position, annunciator (3) will be lit and the associated protection channel will be tripped. Under this condition, annunciator (1) will be lit unless annunciator (5) is lit (i.e., the channel is bypassed).

7.2.3 SYSTEM EVALUATION

7.2.3.1 System Logic

The RPS is a four-channel, redundant system in which the four protective channels are brought together in four identical 2-out-of-4 logic networks of the RT modules. A trip in any 2 of the 4 protective channels initiates a trip of all four logic networks. The system to this point has the reliability and advantages of a pure 2-out-of-4 system.

Each of the reactor trip modules (2-out-of-4 logic networks) controls a control rod drive breaker or contactor. Thus, a trip in any 2 of the 4 protective channels initiates a trip of all the breakers and
9 contactors. The breakers and contactors, however, are arranged in what is effectively a 1-out-of-2 logic

(Figure 7-4). This system combines the advantages of the 2-out-of-4 and the 1-out-of-2 × 2 system alone. The combination results in a system that is considered superior to either of the basic systems alone.

In evaluating system performance, it is arbitrarily assumed that "failure" can either prevent a trip from occurring or can initiate trip action.

The redundant Reactor Protective System inputs operate in a true 2-out-of-4 logic mode so that the failure of an input leaves the system in either a 2-out-of-3 or a 1-out-of-3 logic mode, with either state providing sufficient redundancy for reliable performance.

The system can tolerate several input function failures without a reduction in performance capability provided the failures occur in unlike variables in different protective channels, or are of a different mode in different protective channels, or all occur within one protective channel. When a single protective channel fails, the system is left in either a 2-out-of-3 or 1-out-of-3 logic mode as explained below.

The protective channel trip relay of each channel is located in the reactor trip module associated with the channel. Within each reactor trip module, there is a logic relay for each protective channel. These combine in each module to form the 2-out-of-4 logic. A Failure Mode and Effects analysis of the reactor trip module has demonstrated that single failures within the module or in its interconnections can produce only the following effects:

1. Trip the breaker associated with the module.
2. Place the system in a 2-out-of-3 mode, as if the associated protective channel had a cannot trip failure.
3. Place the system in a 1-out-of-3 mode, as if the associated protective channel had tripped.

The combination of reactor trip modules and control rod drive breakers and contactors form a 1-out-of-2 × 2 logic. At this level the system will tolerate a "cannot trip" type of failure of one reactor trip module, or of the breaker and/or contactors associated with one reactor trip module without degrading the system's ability to trip all control rods. The failure analysis demonstrates that no single failure involving a reactor trip module will prevent its associated breakers and contactors from opening.

7.2.3.2 Redundancy

The design redundancy of the Reactor Protective System would allow physically removing all the components associated with a single protective channel. Doing so would have all the remaining components and protective channels operational in a 1-out-of-3 system.

7.2.3.3 Electrical Isolation

All signals leaving the Reactor Protective System are isolated from the system either by the use of
5 isolation amplifiers for analog signals, by relay contacts (in the case of digital signals), or by optical
5 isolators for the BWNT STAR hardware and relay contacts. The effect of this isolation is to prevent faults occurring to signal lines outside of the Reactor Protective System cabinets from being reflected into more than one Protective channel. The isolation thus provided also assures that two or more protective channels cannot interact through the cross-coupling or faulting of related signal lines.

Faults such as short, open, or grounded circuits and cross-coupling of analog output signals from two or more channels have no effect upon the protective channels or their functions.

The isolation amplifier circuits have been prototype tested to assess their effectiveness to isolate the input signal from output circuit faults. They are capable of blocking a direct connection (i.e., a hot short)

across their output of 410 vdc (300 v rms) without affecting the input source. The redundancy and coincidence logic of the system permits the system to tolerate failures and thus reduces the chance of an
7 inadvertent reactor trip. The BWNT STAR hardware for the Flux/imbalance/flow trip string uses optical
5 isolators rated at 500 VAC, ± 700 VDC galvanic isolation.

7.2.3.4 Periodic Testing and Reliability

The use of 2-out-of-4 logic between protective channels permits a channel to be tested on-line without initiating a reactor trip. Maintenance to the extent of removing and replacing any module within a protective channel may also be accomplished in the on-line state without a reactor trip.

To prevent either the on-line testing or maintenance features from creating a means for unintentionally negating protective action, a system of interlocks initiates a protective channel trip whenever a module is placed in the test mode or is removed from the system. However, provisions are made in each protective channel to supply an input signal which leaves the channel in a non-tripped condition for testing or maintenance.

The test scheme for the Reactor Protective System is based upon the use of comparative measurements between like variables in the four protective channels, and the substitution of externally introduced digital
5 and analog signals as required, together with measurements of actual protective function trip points.

On-line testing may be performed at different intervals and levels within the system consistent with satisfactory system reliability characteristics. The reliability of the system for random failures has been assured by careful selection of components, failure testing of logic elements, environmental testing of the system's modules, and long-term prototype proof-testing with the Babcock and Wilcox Test Reactor (BAWTR).

The reliability of the system logic, primarily the relays and coincidence networks in the RT modules, has been made very high so as to eliminate the need for frequent tests of the logic. The logic relays are of two classes; one class designed for high speed, light electrical loads, and more than 10^7 operations under load; and the other class for switching electric loads of up to 10 amperes and than 10^6 operations. Confirmation tests of operational reliability of these two types of relays, operated under load as they are used in the RPS, have been performed with no sign of failure or wear to 5×10^6 and 1.2×10^6 operations respectively.

The system test scheme includes frequent visual checks and comparisons within the system on a regular schedule in which all protective channels are checked at one time, together with less frequent electrical tests conducted on a rotational plan in which tests are conducted on different protective channels at different times.

A regular check of all Reactor Protective System indications is required. The check includes such things as comparing the value of the analog variables between protective channels and observing that the equipment status is normal. In addition, power-range protective channel readings are compared with a thermal calculation of reactor power. These checks are designed to detect the majority of failures that might occur in the analog portions of the system as well as the self-annunciating type of failure in the digital portions of the system. The electrical tests are designed to detect more subtle failures that are not
5 self-evident or self-annunciating and are detectable only by testing.

Electrical tests are conducted on a rotational basis in accordance with a preliminary test scheme as follows:

5 1. Prior to startup (following a refueling outage), all Reactor Protective System channels, logic, and
5 control rod drive power breakers are electrically trip tested to prove their operability. Testing is
5 performed on a 45 day staggered test bases, for example:

5 2. 45 days after startup, protective channel A is electrically trip tested for every input up to and including
5 the channel trip relay.

5 3. 90 days after startup, protective channel B is similarly tested.

5 4. 135 days after startup, protective channel C is similarly tested.

5 5. 180 days after startup, protective channel D is similarly tested.

5 6. 225 days after startup, protective channel A is similarly tested.

5 The rotational cycle is repeated so that a different protective channel is electrically trip tested every 45
5 days.

The control rod drive power breaker with a reactor trip module is tested monthly.

Rotational testing has several advantages. It significantly reduces the probability of system failure as compared to testing all protective channels at one time. It also reduces the chance of systematic errors entering the system.

7.2.3.5 Physical Isolation

The need for physical isolation has been met in the physical arrangement of the protective channels within separate cabinets and wiring within the cabinets separating power and signal wiring so as to reduce the possibility of some physical event impairing system functions. The systems sensors are separated from each other. There are four pressure taps for the reactor coolant pressure measurements to reduce the likelihood of a single event affecting more than one sensor. Outside the Reactor Protective System cabinets, vital signals and wiring are separated and physically protected to preserve protective channel independence and maintain system redundancy against physical hazards.

Redundant detectors and transmitter applied in the Reactor Protective System are located to provide physical separation. Redundant out of core nuclear detectors are located in separate quadrants around the reactor vessels. Two resistance thermometers assigned to the RPS are located on each reactor coolant outlet header. Cables approach redundant temperature detectors from opposite directions. Redundant pressure transmitters are located outside the secondary shield in four separate quadrants of the Reactor Buildings. Two reactor coolant pressure transmitters for RPS are connected to each of the two loops. Separate flow transmitters for each RPS channel are applied to sense the flow in each loop. This arrangement results in detectors and transmitters associated with one RPS channel being located in essentially (the reactor vessels are not in the center of the Reactor Buildings) the same quadrant of a Reactor Building, and with redundant detectors and transmitters located in another quadrant of the Reactor Building. Since each RPS channel receives a flow signal from both loops, one of the flow transmitters for each channel is not located with the other RPS transmitters for that channel. Location and cable routing for these transmitters is such that separation of at least seven feet is provided between redundant channels inside the Reactor Buildings. Cables for redundant RPS and ES detectors and transmitters are routed in separate directions to four separate Reactor Building penetrations in trays carrying only nuclear instrumentation, RPS, ES, and accident monitoring instrumentation. These penetration assemblies are assigned to nuclear instrumentation, ES instrumentation, accident monitoring instrumentation, and RPS cables exclusively. Two of these penetration assemblies are located sixty feet apart in separate quadrants of each Reactor Building. One is used for RPS and ES channel A instrumentation; the other for RPS and ES channel B instrumentation. A penetration assembly for RPS and ES channel C instrumentation and one for RPS and ES channel D are located on the opposite side of the Reactor Buildings thirty feet apart. Located under the control rooms between the outside of the Reactor Buildings and the cable and equipment rooms, four separate trays are provided per unit which carry nothing but nuclear, RPS, ES, and accident monitoring instrumentation cables. Three separate routes are followed by these trays. RPS channel C and RPS channel D follow the same route but are separated vertically by 1-1/2 feet. A detailed review of cable tray and pipe routing in this area indicates that no more than two RPS channels could be damaged by a single pipe failure or missile. Equipment locations in the Auxiliary Building provide the basis for vertical arrangement of trays following the same route from the Reactor Buildings. Switchgear for power equipment is located at lower elevations and instrumentation cabinets are located at higher elevations. Therefore, vertical separation of classes of cables in trays is as follows from top trays down:

1. Instrumentation cable trays
2. Control cable trays
3. Power and control cable trays
4. Power cable trays

Inside the cable rooms, cables from each protective channel are routed in trays separate from those carrying cables from any other protective channel. Included in these trays are instrumentation cables from the Reactor Building, control and interconnecting cables associated with that protective channel, and non-protective instrumentation and control cables. Both protective and non-protective cables are individually armored and are flame retardant.

Reactor trip cables from the four RPS cabinets are routed separately to a reactor trip switch located on the main control board. From the trip switch, the cables follow four separate paths to the reactor trip breakers and the control rod drive cabinets.

7.2.3.6 Primary Power

The primary source of 120V ac power for the Reactor Protective System comes from four vital buses, one for each protective channel, as described in Section 8.3.2.1.4, "120 Volt AC Vital Power Buses."

7.2.3.7 Manual Trip

Manual trip may be accomplished from the control console by a trip switch. This trip is independent of the automatic trip system. Power from the control rod drive power breakers' undervoltage coils comes from the RT modules. The manual trip switches are between the reactor trip module output and the breaker undervoltage coils. Opening of the switches opens the lines to the breakers, tripping them. There is a separate switch in series with the output of each reactor trip module. All switches are actuated through a mechanical linkage from a single pushbutton.

7.2.3.8 Bypassing

Each protective channel is provided with two key-operated bypass switches, a channel bypass switch and a shutdown bypass switch.

The channel bypass switch enables a protective channel to be bypassed without initiating a trip. Actuation of the switch initiates a visual alarm on the main console which remains in effect during any channel bypass. The key switch will be used to bypass one protective channel during on-line testing. Thus, during on-line testing, the system will operate in 2-out-of-3 coincidence. The use of the channel bypass key switch is under administrative control.

The shutdown bypass switch enables the power/imbalance/flow, power/RC pumps, low pressure, and pressure-temperature trips to be bypassed allowing control rod drive tests to be performed after the reactor has been shut down and depressurized below the low reactor coolant pressure trip point. Before the bypass may be initiated, a high pressure trip bistable, which is incorporated in the shutdown bypass circuitry, must be manually reset. The setpoint of the high pressure bistable (associated with shutdown bypass) is set below the low pressure trip point. If pressure is increased with the bypass initiated, the channel will trip when the high pressure bistable (associated with shutdown bypass) trips. The use of the shutdown bypass key switch is under administrative control.

For maintenance purposes, a bistable may be removed from the system and a dummy bistable inserted in
5 its place, thus bypassing the original function. Installing a dummy bistable forces the protective channel
5 into a trip state upon removal of the bistable. Thus, the removal and substitution cannot be performed
7 without passing through a tripped condition. The installation of the BWNT STAR hardware in the
5 flux/imbalance/flow (fif) trip string requires the use of jumpers to bypass the trip string. The installation
5 of jumpers to bypass the fif trip does not require the removal of the STAR processor module, therefore,
5 the protective channel is not forced into a tripped condition. The use of dummy bistable modules and
5 jumpers is under administrative control.

7.2.3.9 Post Trip Review

9 Post trip review data and information capabilities are provided by use of time history and sequence of
9 events recording equipment. Time history data is provided by the transient monitoring application of the
9 Process Monitoring Computer system (PMC). Sequence of events is determined by data from the
9 sequence of events recorder (SER), the OAC, and the PMC system. This equipment, along with OAC
9 input and operator interviews, provides sufficient information on plant parameters to assure that the
9 course of the reactor trip can be reconstructed as well as provide root cause determination. In the event of
9 failure of the PMC system, information necessary to conduct a post-trip review or transient investigation
9 can be retrieved from other independent sources, such as the OAC and control room chart recorders. See
9 Reference 1 and Section 7.7.2, "Information Display and Control Functions."

7.2.4 REFERENCES

1. H. B. Tucker letters to H. R. Denton (NRC), November 4, 1983 and February 27, 1986. Response to Generic Letter 83-28 Item 1.2.

7.3 ENGINEERED SAFEGUARDS PROTECTIVE SYSTEM

0 **Note**

0 This section of the FSAR contains information on the design bases and design criteria of the
0 system/structure. Additional information that may assist the reader in understanding the system is
0 contained in the design basis document (DBD) for this system/structure.

The Engineered Safeguards Protective System (ESPS) monitors parameters to detect the failure of the Reactor Coolant System and initiates operation of the High and Low Pressure Injection Systems, the Building Isolation, the Reactor Building Cooling and the Reactor Building Spray Systems. In addition, the signal is used to start the standby power source and initiate a transfer to the standby power source when required as described in Section 8.3.1.1.3, "4160 Volt Auxiliary System."

7.3.1 DESIGN BASES

The design basis of the system includes the items of Section 7.1.2, "Identification of Safety Criteria" with the following additions:

7.3.1.1 Loss of Power

1. The loss of vital bus power to the instrument strings will, with the exception of Reactor Building Spray, initiate a trip of that portion of the logic associated with the affected instrument string.
2. The loss of vital bus power to the system logic will not initiate system actuation.

7.3.1.2 Equipment Removal

1. Removing modules from an instrument string will, with exception of Reactor Building Spray, initiate a trip in that portion of the logic associated with the affected instrument string.
2. Removing logic modules from one protective channel does not affect any other protective channel and does not initiate system action.

7.3.1.3 Control Logic of ESF Systems

All systems receiving the ES signal remain in the emergency mode required by the ES actuation after the signal is reset. A separate deliberate action is required to shut off the ES systems and power supplies.

The following systems have been modified to conform to the above requirement of I.E. Bulletin 80-06:

1. HPI Pumps
2. Penetration room exhaust fans
3. Reactor Building Cooling Unit fans
4. Keowee Start

7.3.2 SYSTEM DESIGN

7.3.2.1 System Logic

The Engineered Safeguards Protective System is a basic 2-out-of-3 coincidence logic system. Each input variable is measured three times, the three redundant signals terminate in three bistables as shown in Figure 7-5.

The Engineered Safeguards Protective System consists of eight 2-out-of-3 coincidence logic networks for actuating the equipment in four safeguards systems, thus each system is actuated by a pair of 2-out-of-3 logic and its outputs are referred to as an Engineered Safeguards Protective System channel. Each safeguards system is therefore actuated by two redundant coincidence logics or protective channels.

The coincidence logic output is normally de-energized. Trip action consists of closing the electrical path through the logic.

The output of the protective channel coincidence logic is connected to the channel's unit control module (UC modules). There is one UC module for every item, (pump, valve, etc.) controlled by the protective channel. A protective channel's UC modules are connected in parallel with the output of the coincidence logic.

The output of the coincidence logic follows a normally closed path in each UC module, finally terminating in an output relay, R_0, within each module. The R_0 relays of a protective channel's UC modules are driven in parallel with the output of the protective channel coincidence logic.

The contacts of the R_0 relay are normally open across a control line terminating in a control relay, CR, in the controller of the equipment assigned to the individual UC module. Power for operating the CR relay is taken from the equipment controller in series with the R_0 relay contacts. Trip action involves energizing the R_0 relay, closing its contacts which in turn energizes the CR relay actuating the assigned equipment.

Each protective channel is equipped with a logic test module (LT module). The LT module, together with the UC module, provides the necessary circuitry to permit trip testing of an individual protective device without tripping an entire protective system or channel.

The UC module also provides a means whereby following a system trip, an individual protective device may be removed from the control of the Engineered Safeguards Protective System and returned to manual control. This block action cannot be initiated prior to a system trip.

The design of the system's logic can be summarized in terms of the systems operation as follows:

1. Each protective action is initiated by either of two protective channels with 2-out-of-3 coincidence between input signals.
2. Protective action is initiated by applying power from the protective channel logic to the individual R_0 relays in the UC modules, which in turn energize the CR relays in each protective device controller.
3. There is a UC module for every safeguards system component (valve, pump, etc.)

7.3.2.2 High and Low Pressure Injection and Reactor Building Non-Essential Isolation Systems

The instrumentation, logic, and actuation of the High and Low Pressure Injection Systems are identical in design. The systems differ only in their actuation set point.

There are three independent reactor coolant pressure sensors. The output of each sensor terminates in an isolation amplifier which provides individually isolated outputs. One output of each pressure measurement goes to the plant computer for monitoring. One output goes to bistables, for initiating high pressure injection and Reactor Building non-essential isolation action and for low pressure injection action. The bistables are identical except for their set point. Bistable action is initiated when the low reactor coolant pressure set points are reached.

The output of the three high pressure injection and Reactor Building Non-Essential Isolation System bistables is combined in series with the trip outputs of three Reactor Building pressure bistables. The combination of reactor coolant pressure and Reactor Building pressure bistables outputs allows either variable to initiate high pressure injection and Reactor Building non-essential isolation.

The series outputs of the bistables are brought together in two identical 2-out-of-3 coincidence logics which form two Engineered Safeguards Protective System channels. Either of the two protective channels is independently capable of initiating the required protective action through redundant high pressure injection and Reactor Building Non-Essential Isolation System equipment.

The outputs of the three Low Pressure Injection System bistables are also combined in series with the independent trip outputs of the three Reactor Building pressure bistables. The combination functions in identically the same way as described for the High Pressure Injection System, with two 2-out-of-3 coincidence logics and protective channels.

7.3.2.3 Reactor Building Cooling and Reactor Building Essential Isolation System

There are three Reactor Building pressure sensors. The output of each sensor terminates in an input isolation amplifier, which provides individually isolated outputs. One isolated output of each pressure measurement goes to the plant computer for monitoring. One output of each pressure measurement goes to a bistable which initiates action when its high building pressure trip point is exceeded. Each input isolation amplifier module contains an analog meter for indicating the measured pressure. Each of the three bistables has contact outputs that are combined in series with the output of the High and Low Pressure Injection System bistables as previously described.

The outputs of the three bistables are brought together in two identical 2-out-of-3 coincidence logics which provide two Engineered Safeguards Protective System channels. Either of the two channels is independently capable of initiating the required protective action. Each protective channel uses redundant
7 protective system devices. The bistable for Channel A Reactor Building Pressure Sensor provides a
7 contact output to the ICS to denote degraded containment conditions.

7.3.2.4 Reactor Building Spray System

The Engineered Safeguards Protective System channels of the Reactor Building Spray System are formed by two identical 2-out-of-3 logic networks with the active elements originating in six Reactor Building pressure sensing pressure switches.

Three independent pressure switches containing normally open contacts form one protective channel's 2-out-of-3 logic inputs. Three other identical pressure switches form the 2-out-of-3 logic inputs of the second protective channel. Either of the two protective channels is capable of initiating the required protective action.

7.3.2.5 Availability of Information

All system analog signals are indicated within the system cabinets and are monitored by the plant computer. All bistable outputs are indicated within the cabinets. Logic outputs are indicated within the cabinets and their state monitored by the plant computer.

Plant annunciators provide the operator with immediate indication of changes in the status of the ESPS. Included are all test switches, except those that are spring loaded to return to the operate position.

7.3.2.6 Summary of Protective Action

Actions initiated by the Engineered Safeguards Protection System are tabulated in Table 7-2. The devices actuated by the Engineered Safeguards Protection System are listed in Table 7-3. Channels indicated may be referred to applicable systems as shown in Figure 7-5. All actuated devices remain in their emergency modes after the reset of an engineered safeguards actuation signal until the devices are reset by operator action.

7.3.3 SYSTEM EVALUATION

The ESPS is a basic three-channel redundant system employing 2-out-of-3 coincidence between measured variables.

The system will tolerate the failure of one of three variables among either the reactor coolant pressure measurements or Reactor Building pressure measurements without losing its ability to perform its intended functions.

The High and Low Pressure Injection and Reactor Building Non-Essential Isolation Systems are actuated by either reactor coolant pressure or Reactor Building pressure, thus providing diversity in actuation. The system will tolerate single or multiple failures within one protective channel without affecting the operation of other protective channels. This is the result of keeping each of the protective channel logics independent of every other protective channel. The independence is carried through the protective channel logic and up to the final actuating CR control relay. This is best illustrated by considering the actuation arrangement for the high pressure injection pumps (Figure 7-5).

There are three High Pressure Injection System pumps which operate in the event of an accident. HP-P1A is under the control of protective channel 1, HP-P1C is under the control of protective channel 2, while HP-P1B is under the control of both channels. Within the motor controller of HP-PlA and HP-PlC there is a single CR control relay controlled by the R_0 relay in the pump's associated Test and Block module. The operation of the protective channel logic, the R_0 relay in relation to the CR relay, was described previously. Should any two of the three reactor coolant pressure variables drop below their bistable set point, both protective channel 1 and 2 logics will trip, energizing the appropriate CR relays, and start the pumps.

Within the motor controller of HP-P1B there are two independent CR relays, each controlled by separate R_0 relays in separate Test and Block modules, one in channel 1 and one in channel 2. The arrangement is identical to the way a channel would control any device since all elements are independent and duplicated through the CR relay. The only common element is the power source for the CR relays which is common to the motor controller. Loss of this power prevents the motor control from operating as well as the pump. Relays that monitor actuator coils for each motor or valve control detect either an open coil or a loss of control power.

The example just presented shows the independence and redundancy of the system. There is redundancy of sensors, logic, and equipment. The redundancy is preserved and kept effective by independence of sensors, instrument strings, logic, and control elements in the final actuator. These characteristics enable the system to tolerate single failures at all levels.

The system protective devices (pumps, valves, etc.) require electrical power in order to operate and perform their functions. The power for operating the CR relays is taken from the power source of the associated device. Loss of power to a CR relay or device does not impair the system functions since there is a second redundant device for each required function. The power for the R_0 relays, logic, and instruments is taken from the plant's system of battery backed vital buses since loss of power at this level could affect the performance capability of the system. The system will tolerate the loss of one vital bus without loss of protective capability.

7.3.3.1 Redundancy and Diversity

The system as evaluated above is shown to have sufficient diversity and redundancy to withstand single failures at every level.

7.3.3.2 Electrical Isolation

The use of isolation amplifiers will effectively prevent any faults (shorts, grounds, or cross connection of signals) on any analog signal leaving the system from being reflected into or propagating through the system. The direct connection of any analog signal to a source of electrical power can, at worst, negate information from the measured variable involved. The use of individual R_0 relays for each controlled device effectively preserves the isolation of each device and of elements of one protective channel from another. Faults in the control wiring between an R_0 relay and its CR relay in the controller of a protective device will not affect any other device or protective channel action.

Separation of redundant Engineered Safeguards (ES) functions is accomplished by assigning the eight actuation channels (Table 7-2) to three groups. Isolation for power, control, equipment location, and cable routing is maintained throughout. Channels 1, 3, 5 and 7 are assigned to one group (odd actuation channels). Channels 2, 4, 6 and 8 are assigned to a second group (even actuation channels). Equipment which is actuated by both the even and odd actuation channels is assigned to a third group. All equipment required to perform a specific ES function is assigned to the same group. For example, a pump motor and all valves required for that pump to perform its function are assigned to the same group.

For Oconee 1, AC power for equipment controlled by the odd numbered actuation channels is supplied from Switchgear Group 1TC (4KV), motor control center 1XSl (600 and 208 volts), actuation power from Vital Power Panelboard 1KVIA and DC control power from DC Panelboard 1DIA. ES functions which are redundant to those controlled by the odd numbered actuation channels are controlled by the even numbered actuation channels. AC power for this equipment in Oconee 1 is supplied from Switchgear Group 1TD (4KV), Motor Control Center 1XS2 (600 and 208 volts), from Vital Power Panelboard 1KVIB, and DC control power from DC Panelboard 1DIB. Where a third unit of ES equipment is used to provide additional redundancy, it is actuated by both the even and odd actuation channels. AC power for this equipment in Oconee 1 is supplied from Switchgear Groups 1TE or 2TC (4KV), Motor Control Center 1XS3 (600 and 208 volts), actuation power from either Vital Power Panelboard 1KVIA for odd channel actuation or Vital Power Panelboard 1KVIB for even channel actuation, and DC power from DC Panelboard 1DIC. Similar arrangements are employed for ES equipment in Oconee 2 and 3 with different power and control sources for each unit. These are described in Section 8.3, "Onsite Power Systems."

7.3.3.3 Physical Isolation

The arrangement of modules within the system cabinets is designed to reduce the chance of physical events impairing system operation. Control wiring between the UC modules and the final actuating devices is physically separated and protected against damage which could impair system operation.

Separation between redundant channels of equipment, control cables, and power cables provides independence of redundant ES functions. Power and control cables for each group of ES equipment are routed in cable trays that contain no cable for redundant equipment. Cables for Reactor Building cooling units enter each Reactor Building through three separate penetrations located at least 25 feet apart and are routed in three different directions to the cooling units. The only other ES equipment located inside the Reactor Buildings are electric motor operated isolation valves which are all common to the odd numbered actuation group discussed above.

7.3.3.4 Periodic Testing and Reliability

The number of elements which can fail in a single instrument string is small as the system coincidence logic is not complex. The redundancy of the logic and the division of protective devices between logics forms a system having two parallel protective channels either of which is capable of performing the required functions. These characteristics are basic to an inherently reliable system. Logic elements are relays which have been selected for reliability and subjected to confirming tests under loads identical to those encountered in the system. The resultant calculated probability of logic failure is several orders of magnitude less than the known or estimated probability of failure of all other system elements.

The built-in test facilities permit an electrical trip test of each analog instrument string by the substitution of signals at the isolation amplifiers.

When an analog instrument string is placed in test, all associated analog subsystem outputs go to the trip state. This assures that protective action cannot be defeated by placing analog instrument strings in test.

To avoid a full protective channel or system trip, the logic is tested in parts, one element at a time. The continuity of the electrical connections from the output of the coincidence logic up to each R_0 relay is tested by means of the LT and UC modules. A LT module can neither prevent a trip of the associated protective channel when protective action is called for nor initiate a trip of the associated protective channel.

An individual protective device may be actuated by means of the UC module manual switch. Operating this switch energizes the R_0 relay as if the protective channel has tripped actuating the associated final device. The module lamp confirms that the module test relay returned to its normal state upon release of the manual switch.

On-line checks of the system will confirm the normal state of the system, principally by comparative readings of similar analog indications between redundant measurements and by the status lamps on bistables and logic modules.

The set points of the pressure switches used for ESPS channels 7 and 8 may be checked by connecting a
7 source of pressure and a pressure gauge to test connections provided. The design provides access for this
check at all reactor power levels.

7.3.3.5 Manual Trip

A manual trip switch is provided in each Engineered Safeguards Protective System channel. There are eight manual trip pushbuttons on the control console, one for each protective channel.

7.3.3.6 Bypassing

The trip functions of the High and Low Pressure Injection and Reactor Building Non-Essential Isolation Systems are bypassed whenever the reactor is to be depressurized below the trip point of the systems. Bypassing must be initiated manually within a fixed pressure band above the protective system trip point. The High Pressure Injection and Reactor Building Non-Essential Isolation System may be bypassed only when the reactor pressure is 1,750 psi or less, and the Low Pressure Injection System may be bypassed only when the reactor pressure is 900 psi or less. The bypass is automatically removed when the reactor pressure exceeds the 1,750 and 900 psi values. This is in accordance with IEEE 279, Section 4.12. The removal set points are above the trip points in order to obtain a pressure band in which the trips may be bypassed during a normal cooldown. The bypasses do not prevent actuation of the HP and LP Injection and Reactor Building Non-Essential Isolation Systems on high Reactor Building pressure. Bypassing is under administrative control. Since the ESPS incorporates triple redundancy in its analog input subsystems, there are three HP injection bypass switches and three LP injection bypass switches. Two of the three switches must be operated to initiate a bypass. Once a bypass has been initiated, the condition is indicated by the plant annunciator and by lamps associated with the bypass switches. The switches are backlighted. No provisions are made for manual removal of a bypass before its automatic removal set point is reached.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

7.4.1 NUCLEAR INSTRUMENTATION

The nuclear instrumentation system is shown in Figure 7-6. The system meets the intent of the Proposed IEEE "Criteria for Nuclear Power Plant Protection Systems," dated August, 1968, (IEEE No. 279), for those elements associated with the Reactor Protective Systems.

7.4.1.1 Design Bases

The nuclear instrumentation (NI) system is designed to supply the reactor operator with neutron information over the full operating range of the reactor and to supply reactor power information to the RPS and to the Integrated Control System (ICS).

The system sensors and instrument strings are redundant in each range of measurement. Measurement ranges are designed to overlap to provide complete and continuous information over the full operating range of the reactor.

7.4.1.2 System Design

The nuclear instrumentation has nine channels of neutron information divided into three ranges of
4 sensitivity: source range, wide range, and power range. The three ranges combine to give a continuous
4 measurement of reactor power from source level to approximately 200 percent of rated power or ten +
decades of information. A minimum of one decade of overlapping information is provided between successive higher ranges of instrumentation. The relationship between instrument ranges is shown in Figure 7-7.

4 The source range instrumentation has four redundant count rate channels originating in four high
4 sensitivity fission chambers. These channels are used over a counting range of 0.1 to 10^5 counts/sec as
displayed on the operator's control console in terms of log counting rate. The channels also measure the
4 rate of change of the neutron level as displayed for the operator in terms of startup rate from -1 to +7
4 decades/min.

4 The wide range instrumentation has four log N channels originating in four electrically identical fission
4 chambers. Each channel provides ten+ decades of flux level information in terms of the log of chamber
4 count rate and startup rate. The fission chamber/wide range monitor output range is from 10^{-8} to 200%
4 power. The startup rate range is from -1 to +7 decades/min. A high startup rate of +2 decades/min. in
4 any channel will initiate a control rod withdraw inhibit.

The power range channels have five linear level channels originating in five composite uncompensated ion chambers. The channels output is directly proportional to reactor power and covers the range from 0 to 125 percent of rated power. The gain of each channel is adjustable providing a means for calibrating the output against a reactor heat balance.

Power range channels NI-5, -6, -7, and -8 supply reactor power level information continuously to the RPS. Dual indicators on the control console provide the operator with both total reactor power information (ϕ), and reactor power imbalance information ($\Delta\phi$), from each of the four channels. The method of obtaining ϕ and $\Delta\phi$ is described in Section 7.4.1.2.1, "Neutron Detectors."

7 The fifth power range channel, NI-9, provides reactor power information to the ICS. The channel is in
7 no way associated with the RPS. Reactor power information is also provided to the ICS from NI-5 and
7 NI-6. Isolation amplifiers are used to provide isolation of the power range signals leaving the RPS
7 cabinets. Isolation amplifiers are used to buffer the signals leaving the RPS cabinets, preventing the
7 reflection of faults on external signal lines back into the RPS. The ICS uses median select logic for
7 selection of the NI-5, NI-6 or NI-9 power range signal to be used for control and display on a recorder
7 located on the control console above the power range indicators.

7.4.1.2.1 Neutron Detectors

4 The detectors used in the source range and wide range channels are fission chambers. The same
4 detector/electronics string provides both source range and wide range outputs.

4

9 Uncompensated ion chambers are used in the power range channels. Power range detectors, except NI-9
9 on Unit 1 which is a three section detector, consist of two nominally 70-inch sections with a single high
9 voltage connection and two separate signal connections. The outputs of the two sections are summed and
amplified by the linear amplifiers in the associated power range channel to obtain a signal proportional to total reactor power (ϕ). A signal proportional to the difference in percent full power between the top and bottom halves of the core, the reactor power imbalance or $\Delta\phi$, is derived from the difference in currents from the top and bottom sections of the detector. The difference signal is displayed on the control console to permit the operator to maintain proper axial power distribution. The manual test and calibration facilities provide a means for reading the output of the individual sections of the detector. Each detector has a combined sensitive volume extending approximately from the bottom to the top of the reactor core.

8 The physical locations of the neutron detectors are shown in Figure 7-8, Figure 7-9, and Figure 7-10.
The power range detectors for channels NI-5, -6, -7, and -8 are positioned adjacent to each of the four
quadrants of the core. The power range detector for channel NI-9 is adjacent to the power range detector
4 for channel NI-5. The source/wide range detectors are located adjacent to each of the four quadrants of
4 the core.

Table 7-4 provides pertinent characteristics of the out-of-core neutron detectors. The flux ranges illustrated in Figure 7-7 are seen to be compatible with these characteristics. Nearly identical Westinghouse out-of-core detectors are presently in use at power reactors as follows:

	Tube Type	Reactors	Utility
4	FC	Haddam Neck	Connecticut Yankee Power
4		San Onofre	Southern California Edison
4		Three Mile Island	GPU Nuclear
4		Crystal River 3	Florida Power Corp.
4			
	UCIC	Haddam Neck	Connecticut Yankee Power

7.4.1.2.2 Test and Calibration

Test and calibration facilities are built into the system to permit an accurate calibration of the system and the detection of system failures in accordance with the requirements of Reactor Protective System design and IEEE No. 279. An annunciator alarm exists to indicate a nuclear instrumentation out of calibration condition.

7.4.1.3 System Evaluation

4 The nuclear instrumentation will monitor the reactor over a minimum 10+decade range from source
4 range to 200 percent of rated power. The full power neutron flux level at the power range detectors will be approximately 3.2 x 10^9 nv. The detectors employed will provide a linear response up to
8 approximately 1.5 x 10^{10} nv before they are saturated.

4 The wide range channels fully overlap the source range and the power range channels as shown in Figure 7-7, providing the continuity of information needed during startup.

The steady-state radial flux distribution within the reactor core will be measured by the incore neutron
9 detectors (Section 7.6.1, "Regulation Systems"). Both the out-of-core (NI-5, -6, -7, and -8) and incore detectors will be used to obtain the axial power distribution. The sum of the outputs from the two sections of each (out-of-core) power range detector will be calibrated to a heat balance. The sum will be recalibrated whenever it is determined that the sum disagrees with the heat balance by 2 percent or more. The signals from the two sections of the detector may be individually read and compared independent of the sum of the outputs. The operator, therefore, may correlate the difference signal against the core power distribution obtained from the incore system.

7.4.1.3.1 Primary Power

The nuclear instrumentation draws its primary power from vital buses and uninterruptable buses described in Section 8.3.2.1.4, "120 Volt AC Vital Power Buses" and Section 8.3.2.1.5, "240/120 Volt AC Uninterruptible Power System."

7.4.1.3.2 Reliability and Component Failure

The requirements established for the Reactor Protective System apply to the nuclear instrumentation. All channel functions are independent of every other channel, and where signals are used for safety and/or control, electrical isolation is employed to meet the criteria of Section 7.1.2, "Identification of Safety Criteria."

7.4.1.3.3 Relationship to Reactor Protective System

The relation of the nuclear instrumentation to the RPS is described in Section 7.2, "Reactor Protective System." Power range channels NI-5, -6, -7, and -8 are associated with the Reactor Protective System.
7 NI-5 and NI-6 also provide information for the Integrated Control System through Isolation Amplifiers.

The periodic test requirements of the Reactor Protective System are not dictated by the accuracy of the power range channels. The accuracy of the linear amplifiers is better than ± 0.2 percent including drift.

7.4.2 NON-NUCLEAR PROCESS INSTRUMENTATION

7.4.2.1 Design Bases

The non-nuclear process instrumentation provides the required input signals of process variables for the reactor protective, regulating, and auxiliary systems. It performs the required process control functions in response to those systems and provides instrumentation for startup, operation, and shutdown of the reactor system under normal and emergency conditions.

7.4.2.2 System Design

The non-nuclear instrumentation provides measurements used to indicate, record, alarm, interlock, and control process variables such as pressure, temperature, level, and flow in the reactor coolant, steam supply, and auxiliary reactor systems as shown in system drawings in Chapter 5, "Reactor Coolant System and Connected Systems," Chapter 9, "Auxiliary Systems," Chapter 10, "Steam and Power Conversion System" and Chapter 11, "Radioactive Waste Management." Process variables required on a continuous basis for the startup, operation, and shutdown of the unit are indicated, recorded, and controlled at the control rooms. Alternate essential indicators and controls are provided at other locations to maintain the reactor in a hot shutdown condition if the control rooms have to be evacuated. Other instrumentation is provided at auxiliary panels with alarm at the control rooms.

Response time and accuracy of measurements are adequate for reactor protective and regulating systems and other control functions to be performed.

7.4.2.2.1 Non-Nuclear Process Instrumentation in Protective Systems

Four independent measurement channels are provided for each process parameter for input to the Reactor Protective System.

Three independent measurement channels are provided for each process parameter and input to the Engineered Safeguards Protective System.

a. Reactor Outlet Temperature

Reactor outlet temperature inputs to the Reactor Protective System are provided by two
7 fast-response resistance elements and associated transmitters in each loop.

b. Reactor Coolant Flow

Reactor coolant flow inputs to the Reactor Protective System are provided by eight high-accuracy differential pressure transmitters which measure flow through calibrated flow tubes welded into the reactor outlet pipe. The power/flow monitor of the reactor protective system utilizes this flow measurement to prevent reactor power from exceeding a permissible level for the measured flow. Operation of each reactor coolant pump breaker is also monitored as an indication of flow.

7 RPS Channel E, provides reactor coolant loop A and loop B flow information to the ICS.
7 Channel E is in no way associated with Reactor Protective functions. Reactor coolant loop A
7 and B flow information is also provided to the ICS from RPS Channel A and RPS Channel B.
7 Optical Isolators are used to provide isolation from the RPS. Optical Isolators are used to buffer
7 the signals leaving the RPS cabinets, preventing the reflection of faults on external signal lines
7 back into the RPS. The ICS uses median select logic for selection of the reactor coolant loop A
7 and B flow signal to be used for control.

c. Reactor Coolant Pressure

7 Reactor Protective System inputs of reactor coolant pressure are provided by two pressure
7 transmitters in each loop.

7 RPS Channel E, provides reactor coolant pressure information to the ICS. Channel E is in no
7 way associated with Reactor Protective functions. Reactor coolant pressure information is also
7 provided to the ICS from RPS Channel A and RPS Channel B. Optical Isolators are used to
7 provide isolation from the RPS. The Optical Isolators are used to buffer the signals leaving the
7 RPS cabinets, preventing the reflection of faults on external signal lines back into the RPS. The
7 ICS uses median select logic for selection of the reactor coolant pressure signal to be used for
7 control and display on a recorder located on the control console.

Engineered Safeguards Protective System inputs of reactor coolant pressure in each loop are provided by redundant pressure transmitters. One pressure signal is utilized for recording, low pressure alarm, and interlock to decay heat removal return flow valves.

d. Reactor Building Pressure

Reactor Building pressure inputs to the Engineered Safeguards Protective System are provided by:

1) Three pressure transmitters which are located outside the Reactor Building. These provide inputs for initiation of Reactor Building isolation, high pressure injection, low pressure injection, and Reactor Building cooling.

2) Three groups of two pressure switches each are located outside the Reactor Building. These provide input signals of high Reactor Building pressure for initiation of Reactor Building spray by safeguards actuation.

Table 7-5 provides pertinent information concerning the NNI sensors supplying inputs to the RPS and ESPS, respectively.

7.4.2.2.2 Non-Nuclear Process Instrumentation in Regulating Systems

7 Selective reduntant measurements and input signals are provided for the process variables required for
7 critical control functions. Selection between the redundant measurements and input signals is performed
7 within the ICS utilizing two types of equipment. The "Control STAR" ™ modules perform valid signal
7 selection between certain redundant signals utilizing the median selection technique. Valid signal selection
7 for the remaining critical control process variables is provided by a Smart Automatic Signal Selector
7 (SASS). The SASS detects a rapid change in signal and automatically switches the SASS output signal to
7 the remaining valid input signal.

7 The SASS instrumentation is located in ICS Cabinet 8 and provides automatic signal selection. The
7 SASS instrumentation monitors the following process signals and selects the valid signal independent of
7 the control board mounted key switch.

7 1. OTSG Operate Level Loop A

7 2. OTSG Operate Level Loop B

7 3. Pressurizer Level

7 The SASS can also detect a mismatch between the two input signals and provides indication of the
7 mismatch on the SASS panel. The plant computer also receives the same signals as SASS and provides
7 mismatch alarms to the operator via the plant computer.

7 The "Control STAR" modules are located in the ICS cabinets and provide automatic selection of the
7 median signal for the following process parameters.

7 1. Reactor Coolant System Pressure

7 2. Reactor Coolant Flow Loop A

7 3. Reactor Coolant Flow Loop B

7 4. Power Range Neutron Flux

7 5. Feedwater Flow Loop A

7 6. Feedwater Flow Loop B

7 7. T-Hot Loop A

7 8. T-Hot Loop B

7 9. T-Cold Loop A

7 10. T-Cold Loop B

7 11. Turbine Header Pressure

7 12. OTSG Start-up Level Loop A

7 13. OTSG Start-up Level Loop B

7 TM - Control STAR is a trademark of Framatome Technologies.

The following inputs to the Integrated Control System are provided:

a. Reactor Outlet Temperature

Selected loop or unit average outlet temperature input is provided in each loop by two fast response resistance elements and associated transmitters.

b. Reactor Controlling Average Temperature

7

Loop or unit average temperature signals are selected for indication and input as controlling average temperature. Automatic selection determined by loop flows is provided for input of the appropriate signals.

Reactor inlet temperature signals required for loop, and unit average or differential temperatures are provided in each loop by two fast response resistance elements and associated transmitters.

c. Reactor Inlet Differential Temperature

7 Reactor inlet differential temperature is calculated, indicated and provided for input to the Integrated Control System.

d. Reactor Coolant Flow

Reactor coolant flow signals are provided for each loop and summed for total flow. Total flow is
7 recorded and "low" total flow is alarmed.

7

Loop "low" flow signals provide the logic for automatic selection of reactor controlling average temperature.

Contacts from reactor coolant pump motor breakers provide fast indication to the ICS that a pump has tripped.

e. Feedwater Temperature

7 Feedwater temperature input is provided by three resistance elements and associated transmitters.
7 The selected input also provides indication and feedwater flow temperature compensation.

f. Feedwater Flow

7 The main feedwater flow measurement in each loop is provided by three redundant differential
7 pressure transmitters that measure flow through a flow nozzle. The automatically selected median
7 feedwater flow signal for each loop is compensated by feedwater temperature. The compensated
7 main feedwater flow signal for each loop is indicated, recorded and input to the ICS.

7 The start-up feedwater flow measurement in each loop is provided by a differential pressure
7 transmitter that measures flow through a flow nozzle. The start-up feedwater flow signal for each

7 loop is compensated by feedwater temperature. The start-up feedwater flow signal for each loop
7 is indicated to the operator.

g. Feedwater Control Valves Differential Pressure

Pressure drop measurement across the valves is provided for input by redundant differential pressure transmitters. The selected input signal is also indicated.

h. Steam Generator Level

Selected "startup" level and "operate" level inputs are provided from each steam generator. Redundant measurements of each level are provided by differential pressure transmitters. Temperature compensation to augment the predetermined compensation for normal operating
7 temperature is provided by two resistance elements and associated transmitters which measure steam generator lower downcomer temperature.

The selected "operate." level input is recorded and "high" level alarmed. The selected "startup" level input is indicated and "low" level alarmed.

A full range level measurement is provided for indication of each steam generator level but does not provide protective or regulating systems input.

i. Steam Generator Outlet Pressure

Selected outlet pressure input is provided from each steam generator. Measurement is made by pressure transmitters in both outlet lines of each steam generator. The selected input is also indicated.

j. Turbine Header Pressure

Turbine header pressure measurement is provided for input by a pressure transmitter in each header line from the steam generators. The selected pressure signal is also recorded, and high and low pressures alarmed. Additional redundant transmitters in each header line provide indication only.

7.4.2.2.3 Other Non-Nuclear Process Instrumentation

The following instrumentation is provided for measurement and control of process variables necessary for proper operation:

7 1. Pressurizer Temperature

7 Pressurizer temperature is measured by three resistance elements and their associated transmitters.
7 Two resistance elements provide temperature compensation of the Inadequate Core Cooling
7 pressurizer level instrumentation. The third resistance element is used by the pressurizer heater
7 controls to calculate reactor coolant system saturation pressure.

7 2. Pressurizer Level Control

7 Pressurizer level is measured by three differential pressure transmitters. One temperature compensated
7 signal is selected for indication, recording, interlock and level control. The selected level control signal
7 provides alarms and interlock to de-energize the pressurizer electric heaters on low level. The level
7 controller output positions the makeup control valve in the High Pressure Injection System to
7 maintain a preset level. Pressurizer level is lowered by reactor coolant letdown or by manual control
7 at the control room.

7 3. Reactor Coolant Pressure Control

7 The reactor coolant pressure signal for control is provided by isolated signals from RPS Channel A,
7 RPS Channel B and RPS Channel E (the fifth channel). The isolated RPS A, RPS B and the RPS

7 E reactor coolant pressure signals are median selected within the ICS by the "Control Star" module to
7 provide the selected RC Pressure control signal. The selected signal is used as an input to pressure
7 switches which provide signals for automatic control of:

7 a. Pressurizer electric heaters.

7 b. Pressurizer spray control valve.

7 c. Pressurizer electromatic relief valve.

7 The heaters are grouped in banks which are energized below preset pressures.

7 The selected signal also provides input to a pressure controller which automatically modulates the
7 output of one bank of heaters to maintain a preset pressure.

7 The spray and relief valve are opened at preset pressures above the desired reactor coolant system
7 operating pressure.

7 The selected signal is recorded and high and low pressures alarmed.

7 Reactor coolant pressure is recorded on two single-pen strip chart recorders. One recorder has a range
7 of 1700-2500 PSIG, and its input is the median selected reactor coolant pressure signal selected for
7 control. The other recorder has a range of 0-2500 PSIG, and its input is from a transmitter in the "A"
7 loop.

7 Reactor coolant temperature is also recorded on three single-pen strip chart recorders. One recorder
7 indicating average termperature receives its input from the reactor coolant average temperature
7 selected for control and has a range of 520°F to 620°F. The second temperature recorder has a range
7 of 520°F to 620°F and its input is selectable from either the Loop A, Loop B, or Average T_{HOT}
7 signals selected for control. The third temperature recorder has a range of 50°F to 650°F and its
7 input is selectable from either of four cold leg RTD's, two located in "A" loop cold legs and two
7 located in "B" loop cold legs.

4. Coolant Pump Control

Interlock signals of reactor coolant inlet temperature are provided to each pump switching logic to prevent operation of more than three pumps during startup until a preset temperature is reached.

5. Feed and Bleed Control

The feed and bleed control instrumentation in the High Pressure Injection System provides control and interlocks to permit adjustment of the reactor coolant boron concentration.

7.4.2.3 System Evaluation

The quantity and types of process instrumentation have been selected to provide assurance of safe and orderly operation of all systems and processes over the full operating range of the plant. Some of the criteria for design are:

7 1. Separate instrumentation and Engineered Safeguards Protective System, Reactor Protective System
7 and Steam Generator Level Control System isolated output signals are used for vital control circuits.

2. Time of response and accuracy of measurements are adequate for protective and control functions to be performed.

3. Where wide process variable ranges are required and precise control is involved, both wide range and narrow range instrumentation are provided.

4. All electrical and electronic instrumentation required for operation is supplied form redundant vital and uninterruptable instrumentation buses.

7.4.2.3.1 Failure in RC Flow Tube Instrument Piping

7.4.2.3.1.1 Reactor Coolant Flow Indication

In each primary loop, reactor coolant flow is detected by measuring the ΔP developed across a flow tube that is an integral part of the outlet piping of the loop. Each flow tube has a high pressure (HP) tap and a low pressure (LP) tap. Connections to the taps are made with 1-inch lines. The 1-inch lines are terminated at root valves located inside the secondary shield wall to HP and LP headers. Five ΔP transmitters are connected between the two headers. Four are used to provide information to the Reactor
7 Protective System. The fifth is used to provide input to the ICS. Isolated output signals from RPS
7 Channel A, RPS Channel B and the fifth transmitter are input to the ICS "Control STAR" modules.
7 The median selected signal provides alarms and indication as described in Section 7.4.2.2.2, "Non-Nuclear Process Instrumentation in Regulating Systems."

Each of the four Reactor Protective System channels receives a ΔP signal from a different one of the four ΔP transmitters. In other words, one transmitter is exclusively assigned to one protective channel. The identical arrangement and assignment of transmitters is used for each of the two primary reactor coolant loops.

Within each Reactor Protective System channel, the square roots of the ΔP signals from each loop are
5 extracted to obtain loop flow signals. The loop flow signals are summed to obtain a total reactor coolant
7 flow signal. The three flow signals are displayed by connecting the STAR CTC to the channel's STAR
7 module. The three signals are monitored by the plant computer.

7 The reactor operator can read the individual loop flows and total flow at the control console. The flow information is available to the operator on the plant computer for each unit.

7.4.2.3.1.2 Failures Considered

The following failures are considered:

1. Break in one of the 1-inch instrument lines.
2. Break in one of the 1/2-inch instrument lines.
3. A leak in one of the instrument lines.
4. Rupture of ΔP transmitter bellows.

7.4.2.3.1.2.1 Break in 1 Inch Instrument Lines

A break of a 1-inch instrument line will result in a reactor trip due to low RC pressure. If the break occurs in a HP line, the reactor will trip due to a high power/flow ratio if the power/flow limit is exceeded.

The operator will receive at least the following alarms and indications:

Alarms:

1. Break in 1-inch HP Instrument Line
   a. Low RC flow.
7 b. Plant computer alarm and alarm log for low flow.
   c. Letdown storage low level.

d. Pressurizer low level.

e. Low reactor coolant pressure.

7 f. Plant computer alarm and alarm log for low RC pressure.

2. Break in a 1-inch LP Instrument Line

Identical alarms as listed for HP line break except RC flow is alarmed on high value.

Indication:

1. Break in a 1-inch HP Instrument Line

a. Control room indication of the Reactor Building atmosphere particulate and gas radioactivities increases.

b. Loop flow indication on console falls to zero.

7 c. Loop flow indication in each RPS channel falls to zero. Flow is not displayed in the RPS
5 channel cabinets unless STAR CTC is connected to channel.

d. Total flow indication on console falls approximately 50 percent.

7 e. Total flow indication in each RPS channel falls approximately 50 percent. Flow is not displayed
7 in the RPS channel cabinets unless STAR CTC is connected to channel.

f. Makeup flow goes to maximum value.

g. RC pressure falls on console indicators and with each RPS channel.

h. Reactor Building pressure and temperature indication rises.

2. Break in a 1-inch LP Instrument Line

Identical indication as listed for HP line break except all loop flow indication goes full scale, total flow indication increases above normal.

7.4.2.3.1.2.2 Break in a ½-inch Instrument Line

A break of a ½-inch instrument line will result in a reactor trip due to low RC pressure. If the break occurs in a HP line, the reactor will trip due to a high power/flow ratio if the power/flow limit is exceeded.

The operator will receive the same alarms and indication as described for the 1-inch instrument line break.

7.4.2.3.1.2.3 Leak in One of the Instrument Lines

If the leak occurs in a HP line the operator will receive a low flow alarm for a 5 percent change in indication flow and a high flow alarm for a similar leak in the LP line. At this alarm Point, the leakage is in excess of 1 gallon per minute, hence Reactor Building radiation monitors will readily detect such a condition and result in leak evaluation, and subsequent action as required by Technical Specifications.

7 Depending on the size of the leak, alarms and indication described in Section 7.4.2.3.1.2.1, "Break in 1
7 Inch Instrument Lines," may occur. If the leak occurs on either of the ΔP transmitters associated with
7 the RPS-A, RPS-B or the fifth channel input, the ICS ″Control STAR″ modules will select the median
7 signal for control and indication as described in Section 7.4.2.2.2, "Non-Nuclear Process Instrumentation
7 in Regulating Systems."

7.4.2.3.1.2.4 Rupture of ΔP Transmitter

If the ΔP transmitter ruptures, such that the high pressure and low pressure sides of the transmitter are no longer isolated, the pressure between the HP and LP headers to which the transmitter is connected will be equalized. Since zero ΔP corresponds to zero flow, the output of all five ΔP transmitters for that affected loop will drop to zero. This will result in an immediate reactor trip if the power/flow limit is exceeded.

The operator will receive the following alarms and indication:

Alarms:

1. Low RC flow.
7 2. Plant computer alarm and alarm log for low flow.

Indication:

1. Loop flow indication on console falls to zero.
7 2. Loop flow indication in each RPS channel falls to zero. Flow is not displayed in RPS channel
5 cabinets unless STAR CTC is connected to channel.
3. Total flow indication on console falls approximately 50 percent.
7 4. Total flow indication in each RPS channel falls approximately 50 percent. Flow is not displayed in
7 RPS channel cabinets unless STAR CTC is connected to channel.

7.4.2.3.1.3 Conclusion

The conclusion of this analysis is that the operator has adequate indication and alarm facilities to quickly recognize a common mode failure in the flow instrumentation for the reactor protection system. Corrective action would therefore be positive and prompt.

7.4.2.3.2 Coincident LOCA and Systematic Failure of Low RCS Pressure Trip Signal.

Several break sizes and locations for the loss-of-coolant accident have been investigated with an assumed systematic failure of the low Reactor Coolant System pressure trip signal. Although this failure is not considered credible, the analysis has shown that either the void shutdown mechanism or the power/flow comparator should provide backup to shut down the reactor and render the Emergency Core Cooling System (ECCS) effective.

7.4.3 EMERGENCY FEEDWATER CONTROLS

7.4.3.1 Emergency Feedwater and Pump Controls

7.4.3.1.1 Design Basis

8 The Emergency Feedwater (EFW) System is designed to start the EFW pumps automatically in the event
8 of loss of both main feedwater pumps or low water level in either steam generator.

8 The EFW control valves are designed to control steam generator level when the EFW System is supplying
8 feedwater to the steam generators.

8 All automatic initiation logic and control functions are independent from the Integrated Control System
8 (ICS).

7.4.3.1.2 System Design

8 Three EFW pumps powered from diverse power sources are provided. These include two independent
8 motor driven pumps, each supplying feedwater to one steam generator; and one turbine driven pump,
8 supplying feedwater to both steam generators.

8 Each of the EFW pumps is supplied with its own independent starting circuit which will start
8 automatically as outlined below. Automatic initiation of the EFW pumps by ATWS Mitigation System
8 Actuation Circuitry is described in Section 7.8, "Anticipated Transients Without SCRAM (ATWS)
8 Mitigation System." These independent control circuits are powered by the 125 VDC station batteries.
8 Each pump is also provided with a control switch with which the operator may start the pump manually.

8 Discharge flow from the EFW pumps is normally aligned and controlled by discharge control valves
8 located in the supply line to each steam generator's emergency feedwater connection. The control valves
8 limit or increase emergency feedwater as necessary to maintain steam generator inventory and cooldown
8 rate. These valves may be automatically controlled, or manually controlled by the operator.

8 Indication is provided in the control room to allow the operator to monitor EFW System parameters
8 during a cooldown.

8 Alarms are provided to alert the operator of conditions exceeding normal limits. Essential plant
8 parameters are annunciated or alarmed by the process computer in addition to specific EFW System
8 alarms.

<u>Motor Driven EFW Pumps (MDEFWP's):</u>

8 Power for the motor driven pumps is normally provided by the normal station auxiliary power system.
8 During loss of offsite power operation, these pumps are aligned to the Emergency Power System

8 Automatic starting of the MDEFWP's is determined by the position of the control room selector switch
8 for each pump. The MDEFWP's are provided with a four position selector switch which allows the
8 operator to select between Off, Auto 1, Auto 2 and Run. When the selector switch is in the Auto 1
8 position, LOW STEAM GENERATOR WATER LEVEL in either steam generator (OTSG) will start
8 the pump after a time delay to prevent spurious actuations. When the selector switch is in the Auto 2
8 position, LOW STEAM GENERATOR WATER LEVEL or LOSS OF BOTH MAIN FEEDWATER
8 PUMPS will start the pump. Loss of both main feedwater pumps is sensed by pressure switches which
8 monitor feedwater pump turbine hydraulic oil pressure.

8 Once automatically started, the MDEFWPs will continue to operate until manually secured by the
8 operator.

8 Cooling water is initiated automatically, upon manual or automatic start of the MDEFWPs.

<u>Turbine Driven EFW Pump (TDEFWP):</u>

8 The steam supply for the TDEFWP turbine is provided from the main steam lines upstream of the main
8 turbine stop valves and/or from the Auxiliary Steam System. Upon loss of station air, the supply is
8 maintained by nitrogen bottle back-ups which are used on the pressure control valves. Should the
8 nitrogen bottle back-ups fail, these control valves would fail to the open position.

8 The steam admission valve to the turbine is controlled by a normally energized solenoid valve. Upon
8 receipt of a manual or automatic start signal, the solenoid valve will de-energize and immediately start the

8 turbine by opening the steam admission valve. The steam admission valve will fail open upon loss of
8 power to the normally energized solenoid valve or loss of supply air.

8 THE TDEFWP auxiliary oil pump is started automatically when the steam admission valve is opened,
8 and provides hydraulic oil pressure for the operation of the TDEFWP governor control valve until the
8 TDEFWP shaft driven oil pump is available. The TDEFWP auxiliary oil pump and its associated
8 circuitry is required for automatic start of the TDEWFP. This equipment is powered from station
8 batteries.

8 Automatic starting of the TDEFWP is determined by the position of the control room selector switch for
8 the pump. The TDEFWP is provided with a three position-pull to lock selector switch. The operator
8 can select between Off, Auto and Run. When the selector switch is in the Auto position, LOSS OF
8 BOTH MAIN FEEDWATER PUMPS, with exception to loss due to the Main Steam Line Break
8 (MSLB) logic, will start the pump. Loss of both main feedwater pumps is sensed by pressure switches
8 which monitor feedwater pump turbine hydraulic oil pressure. The MSLB circuitry will inhibit the
8 TDEFWP from auto starting. The TDEFWP may be manually started with a MSLB signal present by
8 setting the selector switch to RUN.

8 Once automatically started, the TDEFWP will continue to operate until manually secured by the operator
8 or shutdown by the MSLB circuitry.

Control Valves:

8 Each emergency feedwater discharge line to each steam generator is provided with a control valve and
8 check valve. The control valves receive an air signal for valve modulation in response to steam generator
8 level, independent from the ICS. A pushbutton is provided for each control valve to allow the individual
8 valve to be placed in either an automatic level control mode or in a manual level control mode of
8 operation. Also provided on the main control board is a manual loader which may be utilized to position
8 the valve when in the manual mode. Open/Closed valve position indication is provided for each control
8 valve in the main control room.

8 The control valves are normally closed in the automatic mode due to steam generator level > setpoint.
8 In automatic, the manual/auto select solenoid valve for each control valve is de-energized, allowing the
8 valve to be positioned automatically.

8 The control valves are arranged to fail to the automatic control mode upon loss of DC control power to
8 the manual/auto select solenoid. If the selected train of automatic control experiences a loss of power,
8 then the valve would fail open. Also, upon loss of station air, the valves will continue to control with N_2
8 backup. If N_2 backup fails then the valve would fail open. These modes of operation show that
8 emergency feedwater isolation is not possible with valve control circuitry or motive force failure.

7.4.3.1.3 System Evaluation

8 Redundancy is provided with separate, full capacity, motor and turbine driven pump subsystems. Failure
8 of either the motor driven pumps or the turbine driven pump will not reduce the EFW System below
8 minimum required capacity. Pump controls, and instrumentation are separate and independent in design.

7.4.3.2 Steam Generator Level Control

7.4.3.2.1 Design Basis

8 The Steam Generator Level Control System (SGLCS) provides automatic Once Through Steam
8 Generator (OTSG) water level control while the EFW System is supplying feedwater to the steam

8 generators. SGLCS is designed to automatically control and modulate emergency feedwater supply to the
8 steam generators during all initiating conditions for the EFW System (Section 7.4.3, "Emergency
8 Feedwater Controls"). Each OTSG has two independent level control systems each of which is capable
8 of supplying a signal to the associated OTSG emergency feedwater level control valve.

8 The Steam Generator Level Control System (SGLCS) provides the automatic start signal for both
8 MDEFWPs based on low level in either steam generator.

8 All automatic initiation logic and control functions are independent from the Integrated Control System
8 (ICS).

7.4.3.2.2 System Design

8 Each OTSG is provided with two independent level control systems, each of which supplies a signal to
8 that OTSG's emergency feedwater level control valve. The two systems provided for each OTSG monitor
8 the 0-388 inch range (range at cold shutdown) of water in the OTSG. A signal deviation check between
8 the two output signals is performed.

8 The SGLCS controls level higher than the normal ICS level setpoint to prevent control system conflict.
8 Upon loss of all four reactor coolant pumps, such as during blackout conditions, the level control setpoint
8 is automatically raised to promote natural circulation in the Reactor Coolant System.

8 The operator has a selector switch on the main control board which is used to select either control
8 channel on each OTSG. Also provided on the main control board is a pushbutton (automatic/manual)
8 and manual loader which may be utilized to override the automatic level control signal provided the
8 control switch which governs this transfer is first engaged.

7.4.3.2.3 System Evaluation

8 Each level channel is separate and independently powered from its counterpart on each OTSG.
8 Redundancy is provided with two trains/channels monitoring each steam generator. Each level channel
8 per steam generator is capable of performing the necessary control and modulation of the feedwater
8 control valves. In addition, sufficient alarms and indications are provided to alert the operator to a system
8 failure and ensure correct manual operation of a level control valve.

7.4.4 REFERENCES

1. *Evaluation of Transient Nuclear Instrumentation Power Range Flux Error* - Duke Power Company - March 1981.
2. Qualification Testing of Protective System Instrumentation Babcock and Wilcox - *BAW - 10003 Rev. 3 - April, 1974 and BAW - 10003A Rev. 4 - January, 1976.*
3. *Evaluation of Reactor Protective System Grounding Concern* Babcock and Wilcox - March, 1978.
4. *177 FA Plants NI/RPS Ground Problem Discussion and Recommended Test Scheme* Babcock and Wilcox - March, 1978.

2 7.5 DISPLAY INSTRUMENTATION

2 7.5.1 CRITERIA AND REQUIREMENTS

2 7.5.1.1 Type A Variables

2 Type A variables are defined as those variables which are monitored to provide the primary information
2 required to permit the Control Room operator to take specific manually controlled actions for which no
2 automatic control is provided and that are required for safety systems to accomplish their safety functions
2 for design basis accidents. Primary information is defined as that which is essential for the direct
2 accomplishment of the specified safety functions; it does not include those variables associated with
2 contingency actions which may also be identified in written procedures.

2 Emergency Procedures provide the lead guidance for selection of Type A variables. The following
2 variables are those determined to be Type A for Oconee Nuclear Station, as defined above:

2 • Reactor Coolant System Pressure
2 • Core Exit (Thermocouples) Temperature
2 • Pressurizer Level
2 • Degrees of Subcooling
2 • Steam Generator Level
2 • Steam Generator Pressure
2 • Borated Water Storage Tank Level
2 • High Pressure Injection Flow
5
2 • Low Pressure Injection Flow
2 • Reactor Building Spray Flow
2 • Reactor Building Hydrogen Concentration
2 • Upper Surge Tank Level
3 • Low Pressure Service Water (LPSW) Flow to Low Pressure Injection (LPI) Coolers.

2 7.5.1.2 Type B and C Variables

2 Type B and C variable selection is based on the Safety Parameter Display System (SPDS) Critical Safety
2 Functions. The SPDS is provided as an aid to the Control Room operating crew in monitoring the status
2 of the Critical Safety Functions. The Critical Safety Functions monitored are those defined in the SPDS
2 Critical Safety Function Fault Trees. The SPDS provides continuous status updated at regular intervals
2 of the Critical Safety Functions.

2 Since these Critical Safety Functions constitute the basis of the Oconee SPDS, it is Duke Power's position
2 that they should also be identified as the plant safety functions for accident monitoring (i.e., the basis for
2 Type B & C variable selection).

2 Using the SPDS Critical Safety Functions as the basis for defining the accident monitoring
2 instrumentation incorporates the concept of monitoring the multiple barriers to the release of radioactive
2 material. The Critical Safety Functions monitored are those which assure the integrity of these barriers.
2 The Fault Tree provides an explicit, systematic mechanism for organizing the plant data required to
2 evaluate a Critical Safety Function. The prioritization of the Critical Safety Functions is consistent with
2 the concept of multiple barriers to radiation release.

The Critical Safety Functions are:

- Subcriticality

The subcriticality fault tree monitors the reactor core to assure that it is maintained in a subcritical condition following a successful reactor trip.

- Inadequate Core Cooling

The inadequate core cooling fault tree monitors those variables necessary to evaluate the status of fuel clad heat removal.

- Heat Sink

The heat sink fault tree monitors the ability to transfer energy from the reactor coolant to an ultimate heat sink.

- Reactor Coolant System Integrity

The Reactor Coolant System integrity fault tree monitors those variables indicating a challenge to or a breach of the Reactor Coolant System pressure boundary.

- Containment Integrity

The containment integrity fault tree monitors those variables which would indicate a threat to containment integrity or other undesirable conditions within containment.

- Reactor Coolant System (RCS)

The RCS inventory fault tree monitors for indications of off-normal quantities of reactor coolant in the primary system.

7.5.1.3 System Operation Monitoring (Type D) and Effluent Release Monitoring (Type E) Instrumentation

7.5.1.3.1 Definitions

Type D: Those variables that provide information to indicate the operation of individual safety systems.

Type E: Those variables to be monitored as required for use in determining the magnitude of the release of radioactive materials and in continually assessing such releases.

The Type D and E variables are selected on the basis of individual plant specific system design requirements.

7.5.1.3.2 Operator Usage

The plant design has included variables and information display channels required to enable the Control Room operating personnel to:

- Ascertain the operating status of each individual safety system to the extent necessary to determine if each system is operating or can be placed in operation to help mitigate the consequences of an accident. (Note: Type D and E are not always safety systems)
- Monitor the effluent discharge paths to ascertain if there have been significant releases (planned or unplanned) of radioactive materials and to continually assess such releases.

- Obtain required information through backup or diagnosis channel where a single channel may be likely to give ambiguous indication.

7.5.1.4 Design and Qualification Criteria

Design and qualification criteria used by Duke Power Company for plant instrumentation are provided below. The category designations are provided for reference to the Regulatory Guide 1.97 (Revision 2) document.

7.5.1.4.1 Design and Qualification Criteria - Category 1

Accident monitoring instrumentation which comprise this design and qualification category are considered by Duke Power to be Nuclear Safety Related and thus are classified as Quality Assurance Condition 1 (QA1).

1. QA1 instrumentation is environmentally qualified as described in the Oconee Nuclear Station IEB-79-01B Duke Power Company submittal and the Resolution of Safety Evaluation Reports for Environmental Qualification of Safety Related Electrical Equipment. Seismic qualification is in accordance with the Oconee Nuclear Station licensing basis as specified in Oconee FSAR Chapter 3, "Design of Structures, Components, Equipment, and Systems" and the Duke Power Seismic Design Criteria (OSDC-0193.01-00-0001).
2. No single failure within either the accident monitoring instrumentation, its auxiliary supporting features, or its power sources, concurrent with the failures that are a condition or result of a specific accident, will prevent the operators from being presented the information necessary to determine the safety status of the plant and to bring the plant to and maintain it in a safe condition following that accident. Where failure of one accident-monitoring channel results in information ambiguity (i.e., the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function, additional information is provided to allow the operators to deduce the actual conditions in the plant. This is accomplished by providing additional independent channels of information of the, same variable (an identical channel) or by providing an independent channel to monitor a different variable that bear a known relationship to the multiple channels (a diverse channel). The information provided to the operator to eliminate ambiguity between redundant channels is needed only during a failure of one of the instrument loops. Therefore, it is considered acceptable to use installed instrumentation of equal design and qualification category, installed instrumentation of a lessor design and qualification category, temporary or portable instrumentation, or sampling to allow the operators to deduce the actual conditions in the plant. Redundant QA1 channels are electrically independent and physically separated from each other per the separation criteria described in Chapter 7, "Instrumentation and Control" of the Oconee FSAR.

   At least one channel of QA1 instrumentation is displayed on a direct indicating or recording device. (Note: Within each redundant division of a safety system, redundant monitoring channels are not needed.)
3. The instrumentation is energized from the safety grade Emergency Power sources (as described in Chapter 8, "Electric Power" of the Oconee FSAR) and is backed by batteries where momentary interruption is not tolerable.
4. The instrumentation channel will be available prior to an accident except as provided in Paragraph 4.11, "Exception" as defined in IEEE Standard 279-1971 or as specified in Technical Specifications.
5. The following documents pertaining to quality assurance are referenced:
   - Duke 1A, Duke Power Company Topical Report, "Quality Assurance Program"
   - Oconee FSAR Chapter 17, "Quality Assurance"

2 6. Continuous indication display is provided. Where two or more instruments are needed to cover a
2 particular range, overlapping of instrument span is provided.

2 7. Recording of instrumentation readout information is provided for at least one of the redundant
2 channels. Recorders which are utilized as the primary display device will be seismically qualified.
2 Where direct and immediate trend or transient information is essential for operator information or
2 action, the recording is continuously available on dedicated recorders. Otherwise, it may be displayed
2 on non-seismically qualified recorders or continuously updated, stored in computer memory, and
2 displayed on demand. Intermittent displays such as data loggers and scanning recorders may be used
2 if no significant transient response information is likely to be lost by such devices. All analog
9 variables which are wired to the plant computer may be trended upon demand and a hard-copy can
9 be generated as needed.

2 **7.5.1.4.2 Design and Qualification Criteria - Category 2**

2 *7.5.1.4.2.1 Nuclear Safety Related (QA1) Category 2 Instrumentation*

2 For instrumentation loops that are installed as nuclear safety related (QA1), environmental qualification is
2 provided per the methodology described in the Oconee Nuclear Station IEB 79-01B submittal and the
2 Resolution of Safety Evaluation Reports for Environmental Qualification of Safety Related Electrical
2 Equipment. Seismic qualification is in accordance with the Oconee Nuclear Station Licensing basis as
2 specified in the Oconee FSAR and Duke Power Seismic Design Criteria (OSDC-0193.01-00-0001).
2 Quality Assurance of these QA Condition 1 instrumentation systems is described in the Duke Power
2 Company Topical Report "Duke 1A" and Oconee FSAR Chapter 17, "Quality Assurance." These
2 instruments are powered from the safety grade Emergency Power sources (as described in Chapter 8,
2 "Electric Power" of the Oconee FSAR) and are backed by batteries where a momentary power
2 interruption is not tolerable.

2 *7.5.1.4.2.2 Non Nuclear Safety Related (Non-QA1) Category 2 Instrumentation*

2 For instrumentation loops of lesser importance which are not nuclear safety related, appropriate
2 qualification is provided. Environmental qualification is provided per the methodology described in the
2 Oconee Nuclear Station IEB 79-01B submittal and the Resolution of Safety Evaluation Reports for
2 Environmental Qualification of Safety Related Electrical Equipment.

2 Category 2 instrumentation which is of primary use during one phase of an accident need not be qualified
2 for all phases of the event. For example, an instrument of primary importance prior to attained the
2 recirculation mode need not be demonstrated to withstand post-recirculation radiation.

2 For non-QA1 Category 2 instrumentation, seismic qualification is not required unless seismic induced
2 failure of the instrumentation would unacceptably degrade a safety system.

2 These instrumentation systems are designed, procured, and installed per Duke Power Company standard
2 practices. Duke Power considers that this is adequate to assure the quality of the subject instrumentation.

2 Isolation devices are provided to interface between Nuclear Safety Related (QA1) and Non Nuclear Safety
2 Related (non QA1) portions of any of the subject instrumentation loops.

2 The instrumentation is energized from a highly reliable power source, not necessarily safety grade
2 Emergency Power, and is backed by batteries where momentary interruption is not tolerable.

2 *7.5.1.4.2.3 All Category 2 Instrumentation*

2 For both Nuclear Safety Related and Non Nuclear Safety Related Category 2 instrumentation:

2 The out-of-service interval should be based on normal Technical Specification requirements for the system
2 it serves where applicable or where specified by -other requirements.

2 The instrumentation signal may be displayed on an individual instrument or it may be processed for
2 display on demand by CRT or by other appropriate means.

2 The method of display may be by dial, digital, CRT, or stripchart recorder indication. Effluent
2 radioactivity monitors and meteorology monitors will be recorded. Where direct and immediate trend or
2 transient information is essential for operation information or action, the recording is continuously
2 available on dedicated recorders. Otherwise, it may be continuously updated, stored in computer
2 memory, and displayed on demand.

2 **7.5.1.4.3 Design and Qualification Criteria - Category 3**

2 These instruments do not play a key role in the management of an accident but they do add depth to the
2 Category 1 and 2 instrumentation to the extent that they remain operable. The instrumentation is of high
2 quality commercial grade and is selected to withstand the normal power plant service environment.

2 The method of display may be by dial, digital, CRT, or stripchart recorder indication. Effluent
2 radioactivity monitors and meteorology monitors will be recorded. Where direct and immediate trend or
2 transient information is essential for operator information or action, the recording is continuously
2 available on dedicated recorders. Otherwise, it may be continuously updated, stored in computer
2 memory, and displayed on demand.

2 **7.5.1.4.4 Additional Criteria for Categories 1 and 2**

2 In addition to the criteria of Duke Position 7.5.1.4, the following criteria apply to Categories 1 and 2:

2 • For Nuclear Safety Related (QA1) signals which are transmitted to non-safety related (non QA1)
2 equipment, isolation devices are utilized.

2 • Dedicated control board displays for the instruments designated as Types A, B, and C, Category 1 or
2 2 and qualified for use throughout all phases of an accident will be specifically identified on the
2 control panels so that the operator can discern that they are available for use under accident
2 conditions.

2 **7.5.1.4.5 Additional Criteria for All Categories**

2 In addition to the above criteria, the following criteria apply to all instruments identified in this document:

2 • Servicing, testing, and calibration programs are specified to maintain the capability of the monitoring
2 instrumentation. For those instruments where the required interval between tests will be less than the
2 normal time interval between generating station shutdowns, the capability for testing during power
2 operation is provided.

2 • Whenever means for removing channels from service are included in the design, the design facilitates
2 administrative control of the access to such removal means.

2 • The monitoring instrumentation design minimizes the development of conditions that would cause
2 meters, annunciators, recorders, alarms, etc., to give anomalous indications which are potentially
2 confusing to the operator. Human factors guidelines are used in determining type and location of

2 displays. The Duke Control Room Review Team made recommendations as to the type and location
2 of displays, for added instrumentation.

- 2 To the extent practicable, the instrumentation is designed to facilitate the recognition, location,
2 replacement, repair, or adjustment of malfunctioning components or modules.
- 2 To the extent practicable, monitoring instrumentation inputs are from sensors that directly measure
2 the desired variables.
- 2 To the extent practicable, the same instruments which are used for accident monitoring are used for
2 the normal operations of the plant to enable the operators to use, during accident situations,
2 instruments with which they are most familiar. However, where the required range of monitoring
2 instrumentation results in a loss of necessary sensitivity in the normal operating range, separate
2 instruments are used.
- 2 Periodic checking, testing, calibration, and calibration verification are in accordance with the
2 applicable portions of the Oconee FSAR Chapter 7, "Instrumentation and Control."

2 7.5.2 DESCRIPTION

2 Display instrumentation provided for Oconee operators is described below.

2 7.5.2.1 Reactor Coolant System Pressure

2 Three channels of Reactor Coolant System (RCS) Pressure indication are available through the plant
2 operator computer (OAC), which receives the RCS Pressure signals through the Engineered Safety
2 Features Actuation System (ESFAS) cabinets. This instrumentation is powered from a highly reliable
2 battery backed source. Two channels are recorded. These instrumentation channels monitor RCS
2 pressure over the range 0 to 2500 psig.

2 Two upgraded QA Condition 1 channels of Wide Range RCS Pressure indication are provided for post
2 accident monitoring in response to Regulatory Guide 1.97. These instrumentation loops are seismically
2 and environmentally qualified and are powered from safety grade emergency power sources. Signals to the
2 Control Board readouts are processed through the Inadequate Core Cooling Monitoring (ICCM) system
2 cabinets. The range for the readouts, 0-3000 psig, is in compliance with Regulatory Guide 1.97
2 specifications.

2 RCS pressure is a Type A variable at Oconee, since the operator relies on this indication to determine
2 when to switch from high pressure injection to low pressure injection.

2 7.5.2.2 Inadequate Core Cooling Instruments

2 The Inadequate Core Cooling Monitor (ICCM) is of Westinghouse design. The ICCM system monitors
2 hotleg level, reactor vessel head level, loop subcooling margin, core subcooling margin and core exit
2 temperature and provides advanced warning of the approach to inadequate core cooling. The ICCM is a
2 redundant two train Nuclear Safety-Related system powered by the vital instrumentation and control
2 power system.

2 The microprocessor-based monitoring trains provide essential information to the control room operator so
2 that conditions inherent to or leading to Inadequate Core Cooling (ICC) can be recognized and addressed.

2 The functions performed by the ICCM are as follows:

- 2 Assists in detecting a void or loss of level in the hotleg during natural circulation.

2 • Indicates loss of subcooling margin.

2 • Assists in detecting presence of a gas bubble or void in the reactor vessel head.

2 • Assists in the detection of the approach to inadequate core cooling.

2 The ICCM system consists, on a per train basis of centrally located electronics/microprocessor cabinet,
2 display electronics package, display selector key pad, and the plasma display unit on the main control
2 board.

2 A description of each of the process sub-systems are described as follows.

2 **7.5.2.2.1 Core Exit Temperature**

2 There are a total of 52 Core Exit Thermocouples (CETs) per Oconee Unit. Twenty-four (12 per train)
2 have been upgraded for accident monitoring and to meet seismic and environmental qualification
2 requirements. t

9 The plant computer is the primary display for 47 CETs. 5 CETs are displayed on the corresponding SSF
9 unit console. The ICCM plasma displays (1 per train) located in the Control Room serve as safety
2 related backup displays for the twenty-four nuclear safety qualified CETs. The range of the readouts is
2 50°F to 2300°F.

2 The ICCM CET function uses inputs from twelve incore thermocouples per train to calculate and display
7 temperatures of the reactor coolant as it exits the core and to provide indication of thermal conditions
2 across the core at the core exit.

2 Each of the twelve qualified thermocouples per train is displayed on a spatially oriented core map on the
2 plasma display. The distribution of the monitored CETs in both trains assure minimum monitoring of at
2 least four per core quadrant. Trending of CET temperature is available continuously on the plasma
2 display. The average of the five hottest CETs is trendable for the past forty minutes.

2 Inputs to the plant computer for thermocouples used in the ICCM backup display is through qualified
2 isolation devices. Power for the backup display is from safety grade emergency power sources, and power
2 for the non-safety Operator Aid Computer (OAC) portion is from a highly reliable battery backed control
2 bus. The plant computer and ICCM backup display are installed in a mild environment.

7 Core exit temperature is classified as a Type A variable at Oconee because the operator relies on this
2 information following a design basis event (LOCA) to secure HPI and throttle LPI, (SBLOCA) to
2 throttle HPI and begin forced HPI cooling if needed, (MSLB, OTSG Tube Rupture) throttle HPI and
2 isolate affected OTSG.

2 (RE: NSMs ON-1/2/32401)

2 **7.5.2.2.2 Degrees of Subcooling Monitoring**

2 The margin to saturation for the hotlegs and the reactor core are calculated from Reactor Coolant System
2 (RCS) pressure and temperature measurements. The hotleg subcooling margin is calculated from wide
2 range RCS pressure measurements and individual hotleg RTD temperature measurements. The hotleg
2 subcooling margins are displayed in the Control Room on the ICCM plasma display unit. Train A
2 displays the RCS Loop A hotleg subcooling margin while the Train B display provides RCS Loop B
2 hotleg subcooling margin. Computer inputs are also provided for both hotlegs.

2 The reactor core subcooling margin is displayed in the Control Room in an identical manner. The core
2 subcooling margin is calculated from the average of the five highest qualified Core Exit Thermocouples
2 (CET's) out of twelve inputs to each train of ICCM. This average value is then used with the RCS
2 pressure measurement to calculate core subcooling margin.

2 The degrees of subcooling is also input to the plant computer through isolation buffers and is recorded on
2 a dedicated chart recorder in the Control Room. The range of the degrees of subcooling readouts is
2 200°F subcooled to 50° superheat which envelopes the Regulatory Guide 1.97 range of 200°F subcooling
2 to 35°F superheat.

2 (RE: NSMs ON-1/2/32401)

2 7.5.2.2.3 Reactor Vessel Head and Hotleg Levels

2 The Reactor Vessel Head Level indicating system (RVHLIS) and Hotleg (HL) system are an adaptation
2 of the Westinghouse RVLIS to the Babcock and Wilcox nuclear steam supply system. The HL and
2 RVHLIS monitor the RCS for voids and loss of level conditions only under natural circulation.

2 The HL and RVHLIS uses two sets of two d/p (differential pressure) cells to measure both vessel and hot
2 leg levels under natural circulation conditions. These cells are used to measure the pressure drop from the
2 hot leg decay heat drop line connection to the top of the vessel, and from the hot leg decay heat drop line
2 connection to the top of the candy cane on each hot leg. This differential pressure measuring system uses
2 cells of differing ranges to cover natural circulation conditions.

2 This is a two train system containing Trains A and B which are physically separate and electrically
2 isolated from each other. The trains perform the same function using identical but redundant inputs from
2 differential pressure transmitters, impulse line temperature sensors, reactor coolant temperature sensors
2 and wide range reactor coolant system pressure.

2 Software algorithms automatically perform compensation calculations required for variations in impulse
2 line temperatures. Software also calculates and provides the necessary compensation for reactor coolant
2 density.

2 Whenever the Reactor Coolant Pumps (RCPs) are running, the subcooling margin monitors and RCP
2 monitor current meters are used to detect possible void conditions. Computer inputs are provided for
2 both trains of level measurement. The Train A level measurements are recorded on a continuous recorder
2 on the Main Control Board. The plasma displays for each train provide indication of both HL and
2 RVHLIS in the Control Room.

2 7.5.2.3 Pressurizer Level

2 Three channels (2-Train A and 1-Train B) of QA 1 instrumentation are provided for post accident
2 monitoring the Pressurizer Level in response to Regulatory Guide 1.97, Revision 2. The indicated range
2 is 0 to 400 inches which represents 11% to 84% level as a percentage of volume. Duke considers this
2 range adequate for the intended monitoring function.

2 In order to determine the range or level that should be monitored for the pressurizer, it is important to
2 understand how the pressurizer is sized and how the level taps are located. The pressurizer water volume
2 is chosen such that the reactor coolant system can experience a reactor trip from full power without
2 uncovering the level sensors in the lower shell and to maintain system pressure above the High Pressure
2 Injection (HPI) system actuation setpoint. The steam volume is chosen such that the reactor coolant
2 system can experience a turbine trip without uncovering level sensors in the upper shell. Oconee has a 0
2 to 400 in range for pressurizer level based on these criteria. Although the installed range of

2 instrumentation is not in complete compliance with the recommendation of Regulatory Guide 1.97,
2 Revision 2, that pressurizer level be monitored from bottom to top, it is consistent with B&W NSSS
2 requirements and is adequate for the intended monitoring function, including monitoring to ensure
2 continued safe operation of pressurizer heaters.

2 The qualified instrument channels are powered by safety grade emergency power sources. Continuous
2 recording is provided for one channel. The range for the instrumentation channels is 0 to 400 inches
2 which Duke considers adequate for the intended monitoring function as referenced in the above
2 paragraph.

2 Pressurizer level is classifed a Type A variable at Oconee because the operator relies on this information
2 following a design basis event (SBLOCA, OTSG Tube Rupture, MSLB) to throttle HPI.

2 (RE: NSMs ON-1/2/32448)

2 7.5.2.4 Steam Generator Level

2 Oconee has several different methods of Steam Generator level measurement and indication, as follows:

7 1. Start-up Range - Four transmitters (two per S/G) feed the ICS with signal ranges of 0″ to 250″. The
7 four channels are used in the ICS for steam generator water level and feedwater control. The ICS
7 employes median select between these signals and isolated signals from Item 4 below to control level
7 and feedwater. The ICS displays the controlling level signal on a dual scale gage on the main control
7 board.

2 2. Operate Range - Four transmitters (two per S/G) are combined with temperature compensation to
2 feed two recorders with ranges of 0-100% (96″-388″). The four channels are switch selectable for
2 feeding the recorders.

2 3. Full Range - Two transmitters (one per S/G) feed one dual gauge with ranges of 0 to 100%
4 (0-650″).

4 4. Extended Startup Range - Four transmitters (two per S/G) feed four gauges with ranges of 0″ to 388″.

8 Items 1 through 3 are used during normal plant operating conditions and are not required to meet
8 Regulatory Guide 1.97, Type A, Category 1 Variable Requirements. These instruments may be used as
8 backup verification for post accident monitoring to the extent they are available.

7 The instrumentation in Item 4 above is safety related and is used for post-accident monitoring. This
7 instrumentation is powered by safety grade emergency power sources and the transmitters are seismically
7 and environmentally qualified. Signal conditioning is provided by seismically and environmentally
7 qualified equipment. Two transmitters, one per steam generator, provide electrically isolated level signals
7 to the ICS for use in steam generator water level and feedwater control. The ICS will display these level
7 signals if they have been selected for control on the control room indicator described in Item 1 above.

2 During accident conditions, the required range for a B&W once through steam generator is based on that
2 level in the steam generator needed to mitigate the effects of a small break LOCA. That range is based on
2 current assumed or known instrumentation errors and is 0″ to 120″. The installed range of 0″ to 388″ is
2 therefore adequate during accident conditions for measuring S/G level.

2 Steam Generator Level is classified a Type A variable at Oconee because the operator relies on this
2 information following a design basis event (MSLB, OTSG Tube Rupture) to isolate affected OTSG.

2 (RE: NSMs ON-1/2/32447)

2 7.5.2.5 Steam Generator Pressure

2 Four QA Condition 1 channels, two channels per steam generator, are provided for post-accident
2 monitoring steam generator outlet steam pressure in response to Regulatory Guide 1.97. Each instrument
2 channel is seismically and environmentally qualified and powered from a safety grade source.

2 Each instrument channel inputs to the Inadequate Core Cooling Monitoring (ICCM) cabinets. The
2 ICCM cabinets, Channel A and B respectively, provide safety inputs to two qualified indicators located
2 on the Main Control Board in the Control Room. One channel per steam generator also provides a
2 safety input to a qualified recorder located in the Control Room. The ICCM system cabinets, channels A
2 and B respectively, also provide non-safety inputs to the Operator Aid Computer (OAC). Safety train
7 integrity is maintained by isolation buffers provided by the ICCM system cabinets. Additionally, each
7 steam line has one QA Condition 1 channel of steam generator pressure instrumentation. These
7 instrument channels along with corresponding ICCM steam generator instrumentation provide input
7 signals into the Main Steam Line Break (MSLB) circuitry. (RE: NSM-1/2/32873)

7 Each steam generator has two non-safety related channels of steam generator outlet pressure
7 instrumentation (total of four) used for control by the ICS. In addition, two channels of QA-1 steam
7 generator outlet pressure instrumentation used in the Main Steam Line Break Isolation logic are
7 electrically isolated and provided to the ICS for control. This makes a total of six pressure signals, three
7 per steam generator, for use in the ICS for control. Each group of three pressure signals (3 - OTSG "A",
7 3 - OTSG "B") are used in median select strategy by the ICS for control. The control signal used in the
7 ICS for each steam generator is provided for indication on the main control board. The indicated range is
7 0 - 1200 psig which corresponds to 14% above the lowest main steam safety relief valve setting and 8%
7 above the highest safety valve setting. All six channels, three per steam generator, are also input to the
7 plant computer (OAC) and trend recording is available to the control room operator if demanded. The
7 non-safety related instrumentation is powered from highly reliable battery backed buses. The
7 safety-related (QA-1) instrumentation is powered from the QA-1 vital instrumentation and control battery
7 backed buses.

2 The main steam lines are provided with safety relief valves, atmospheric dump valves and condenser dump
2 valves to prevent over pressurization of the lines as well as pressure control. Operability of the main
2 steam safety valves ensures that the secondary system pressure will be limited to within its design pressure
2 (1050 psig) during the most severe anticipated system operating transient. With an assumed 3%
2 accumulation when these safety valves are operating, the maximum pressure while they are relieving will
8 be less than 10% above design pressure. Also the Facility Operating License limit the plant power and
2 thus steam flow in order to maintain that excess relief capacity. Therefore, based on the facts that the,
2 highest safety valve setting is 1104 psig, the steam relief capacity is 17% above the expected steam flow
2 rate and that excess relief capacity is maintained when safety valves are inoperable, the existing range of 0
2 to 1200 psig is sufficient for this variable.

2 Steam Generator Pressure is classified a Type A variable at Oconee because the operator relies on this
2 information following a design basis event (MSLB, OTSG Tube Rupture) to isolate affected OTSG.

2 (RE: NSMs ON-1/2/32447)

2 7.5.2.6 Borated Water Storage Tank Level

2 Three QA Condition 1 channels of level instrumentation are provided for normal and post accident
9 monitoring the Borated Water Storage Tank (BWST) level. Each channel is seismically qualified. Two
9 channels are powered from a safety grade source and the third channel has a safety and a non-safety grade
9 power distribution. Signals to the Control Board are processed through the Inadequate Core Cooling

2 Monitoring (ICCM) system cabinets. The range for the readouts, 0 to 50 ft (13%-100% of volume), is in
2 compliance with Regulatory Guide 1.97, Rev. 2.

2 Two of the three QA Condition 1 instrumentation channels provide inputs to the ICCM system cabinets,
2 Train A and B respectively. The ICCM cabinets provides safety inputs to qualified indicators on the
2 Control Board and non-safety inputs to the Operator Aid Computer (OAC). Safety train integrity is
2 maintained through the use of isolation buffers provided by the ICCM system.

2 The third channel of qualified instrumentation provides a safety input from train B to a dedicated
2 qualified recorder. This channel also provides input to the computer and various annunciators via an
2 optical isolator which maintains safety train B integrity.

2 BWST level is classified a Type A variable at Oconee because the operator relies on this information
2 following a design basis event (LOCA, SB LOCA) to realign LPI to take suction from RB sump.

2 (RE: NSMs ON-1/2/32450)

2 7.5.2.7 High Pressure Injection System and Crossover Flows

2 Two channels of QA condition 1 instrumentation are provided for post accident monitoring of High
2 Pressure Injection (HPI) flow in response to Regulatory Guide 1.97. Each channel is seismically and
2 environmentally qualified and powered from a safety grade source. Each channel signal, A and B
2 respectively, inputs to a dedicated qualified recorder and qualified indicator via the Inadequate Core
2 Cooling Monitoring (ICCM) system cabinets. Two channels of QA condition 1 instrumentation are also
2 provided for monitoring HPI crossover flow. These instrument channel signals directly input to qualified
2 indicators on the Control Board. HPI System and Crossover Flow instrumentation channels monitor
2 flow over the range 0 - 750 gpm which envelopes the 0 to 110% design flow criteria of Regulatory Guide
2 1.97, Rev. 2.

2 The ICCM cabinets also provide non-safety inputs to the Operator Aid Computer (OAC) and
2 annunciator points. Safety channel integrity is maintained through the use of isolation buffers provided in
2 the ICCM.

5 HPI System flow is a Type A variable at Oconee because the operator relies on this information following
2 a design basis event (LOCA, SB LOCA, MSLP, OTSG Tube Rupture) to throttle HPI and initiate HPI
2 bypass (if necessary).

2 (RE: NSMs ON-1/2/32589)

3 7.5.2.8 Low Pressure Injection System Flow

2 Two QA Condition 1 instrumentation channels are provided for normal and post accident monitoring
2 Low Pressure Injection (LPI) flow in response to Regulatory Guide 1.97. Each channel is seismically and
2 environmentally qualified and powered from a safety grade source. Each channel signal, train A and B
2 respectively, inputs to a qualified indicator and qualified recorder via the Inadequate Core Cooling
2 Monitoring (ICCM) system cabinets. These channels monitor LPI flow over the range 0-6000 gpm
3 which envelopes the 0-110% of design flow criteria for Regulatory Guide 1.97.

2 The ICCM cabinets also provide non-safety inputs to the Operator Aid Computer (OAC) and
2 annunciator points. Alarms generated in the ICCM cabinets provide high and low LPI flow and low
2 Decay Heat removal flow for each train. Safety train integrity is maintained through the use of isolation

2 buffers provided by the ICCM. Two non-qualified transmitters, one per train, also provide non-safety
2 inputs to the OAC.

2 LPI System is a Type A variable at Oconee because the operator relies on this information following a
3 design basis event (LOCA, SB LOCA) to throttle LPI flow.

2 (RE: NSMs ON-1/2/32587)

2 7.5.2.9 Reactor Building Spray Flow

2 Two QA Condition 1 instrumentation channels are provided for post accident monitoring Reactor
2 Building Spray flow in response to Regulatory Guide 1.97. Each instrumentation channel is seismically
2 and environmentally qualified and powered from a safety grade source. Each instrument channel signal,
2 train A and B respectively, inputs to a qualified indicator and qualified recorder via the inadequate core
2 cooling monitoring (ICCM) cabinets. These channels monitor Reactor Building Spray flow over the
2 range 0-2000 gpm which envelopes the Regulatory Guide 1.97 range requirement of 0-110% of design
2 flow.

2 The ICCM cabinets also provide non-safety inputs to the Operator Aid Computer (OAC), annunciator,
2 and a non-safety indicator located in the Control Room. Safety train integrity is maintained through the
2 use of isolation buffers provided by the ICCM system. Also provided is two non-safety instrument
2 channels which provide non-safety inputs to the OAC.

2 RBS Flow is a Type A variable at Oconee because the operator relies on this information following a
3 design basis event (LOCA, SB LOCA) to throttle RBS flow.

2 (RE: NSMs ON-1/2/32588)

2 7.5.2.10 Reactor Building Hydrogen Concentration

2 Two redundant channels of nuclear safety related instrumentation monitor reactor building hydrogen
2 concentration. The indicated range is from 0 to 10% concentration which envelopes the Regulatory
2 Guide 1.97 range requirements.

2 Both channels are powered by safety grade emergency buses. Control of the sample line switching valves
2 and sample selector solenoid valves is accomplished at the analyzer remote control panel. These
2 instruments are seismically and environmentally qualified. (RE: FSAR 9.3.7, "Containment Hydrogen
2 Monitoring System")

2 7.5.2.11 Upper Surge Tank and Hotwell Level

2 Oconee's Emergency Feedwater System (EFDW) draws condensate grade suction from the Upper Surge
2 Tanks and the Condenser Hotwell. Condensate may also be provided from the Condensate Storage Tank
2 (CST) and the Makeup Demineralizers. Additional backup of the two normal condensate sources is
2 provided by these same locations associated with the other two units. The level transmitters which
2 monitor Upper Surge Tank and Hotwell level are located in the Turbine building which is a mild
2 environment.

2 Category 3 instrumentation is available to monitor Hotwell level in the Control Room. One continuous
2 recorder and computer monitoring point is provided to monitor this variable.

2 Two QA Condition 1 instrumentation channels are provided for monitoring Upper Surge Tank (UST)
9 level in response to Regulatory Guide 1.97. These instrument channels are seismically qualified and
2 powered from a safety grade source. Each instrument channel, train A and B respectively, input to the
2 Inadequate Core Cooling Monitoring (ICCM) system cabinets. The ICCM Train A cabinet provides
2 safety inputs to a dedicated qualified recorder and to a qualified indicator located in the Control Room
2 which provides UST level indication. The ICCM Train B cabinet also provides a safety input to a
2 qualified indicator located in the Control Room. The range of UST level indication is 0 - 12 feet.

2 The ICCM cabinets, Train A and B respectively, also provide non-safety inputs to two computer alarm
2 points and one annunciator window. Safety train integrity is maintained through the use of isolation
2 buffers provided by the ICCM system.

2 Upper Surge Tank level is a Type A variable at Oconee because the operator relies on this information
3 following a design basis event.

2 (RE: NSMs ON-1/2/32449)

2 7.5.2.12 Neutron Flux

4

4 Oconee has four channels of neutron flux for the source range, and four wide range QA Condition 1
4 channels of full range neutron flux instrumentation which are environmentally qualified for post-accident
4 monitoring. Five neutron flux channels exist for the power range. The indicated ranges are: Source
4 Range 10^{-1} to 10^{5} cps, -1.0 to +7.0 decade/min. rate of change; Wide range (Post-Accident Monitoring
4 channels) 10^{-8} to 200% power, -1 to +7 decade/min. rate of change; and Power Range, 0 to 125%.

4 NI-1,-2,-3, and -4 channels are environmentally qualified and powered from safety grade busses and
2 encompass the 10^{-6} to 100% Full Power range in response to Regulatory Guide 1.97, Rev. 2. All other
2 NI channels are designed for the normal Reactor Building Environment for the safety function of
2 overpower reactor trip but they are not environmentally qualified for post-accident operation.

2 Operator information is provided as follows:

4 • Seventeen Control Room indicators (Four source, four wide, five power)

4 • Twenty-one computer points (Eight source, eight wide range, and five power)

2 • Trend recording on demand

2 • One QA Condition 1 Wide Range channel recorded on a post-accident operation recorder. One
4 source range, wide range, and power range channel recorded, four (two power range) channels
4 accessible on a Non-QA Condition recorder.

4 RE: NSMs ON-1/2/32596 and 1/2/32909)

2 7.5.2.13 Control Rod Position

2 Each control rod's position is indicated on an analog display which has two switchable input modes for
2 the full 0 to 139 inch range. In addition, separate Full In and Full Out indicating lights are provided for
2 each control rod. Analog computer points are provided for each control rod's position. Analog computer
7 points are also provided for control rod groups 5, 6, 7 and 8, for zero to 100% rod position corresponding
7 to the full 0 to 139 inch range. This instrumentation is powered from a highly reliable battery backed
2 source. (Re: FSAR 4.5.3, "Control Rod Drives").

2 Operator information is provided as follows:

2 • Indicating lights for Full In or Not Full In for all control rods.
2 • Analog display full range for all control rods.
2 • Computer inputs for all control rods and all control rod groups 5, 6, 7, and 8. Trend recording on
2 demand.

2 7.5.2.14 RCS Soluble Boron Concentration

2 This variable is monitored by sampling and laboratory analysis. Primary system boron concentration is
2 controlled manually with the sampling frequency determined by plant conditions and operating
2 procedures. In addition post-accident sampling of the RCS is available (Re: FSAR 9.3.6.1,
2 "Post-Accident Liquid Sampling System"). Neutron flux indication also provides indication of reactor
2 subcriticality (Re: FSAR 7.5.2.12, "Neutron Flux"). Duke considers these measures adequate for the
2 intended monitoring functions.

2 7.5.2.15 Reactor Coolant System Cold Leg Water Temperature

2 Oconee has indication of Reactor Coolant System (RCS) Cold Leg Temperature for each of the four cold
2 legs. The instrumentation is powered from a highly reliable battery backed source. The indicated range is
2 50° to 650°F. Additional diversity is provided by the Hot Leg Water Temperature and Core Exit
2 Temperature Instruments.

2 The RCS Cold Leg Water Temperature is used as a backup for the key variable of Hot Leg Temperature
2 and Core Exit Temperature. Because the Hot Leg and Cold Leg RTD's are located in the RCS loops
2 and not in the reactor vessel, either forced or natural circulation is required through the steam generators
2 for their indication to be representative of actual core conditions. When circulation is present, the 650°F
2 high end of the range provides 18% excess measurement capability based on a steam generator design
2 pressure of 1050 psig and a saturation temperature of approximately 553°F for the Oconee design.
2 Because the RCS Cold Leg Temperature is not used in the ATOG guidelines and functions as backup to
2 the other two variables, it is appropriate to classify this variable as a Category 3. The existing design is
2 adequate for the intended monitoring function.

2 7.5.2.16 Reactor Coolant System (RCS) Hot Leg Water Temperature

2 Two qualified, QA condition 1 channels, are provided for post-accident monitoring Wide Range RCS
2 Hotleg Water Temperature in response to Regulatory Guide 1.97 Rev. 2. These instrument channels are
2 powered from safety grade emergency power sources. The indication readouts are located in the Control
2 Room in a mild environment. This variable inputs to the plant computer through isolation buffers and is
2 recorded on a dedicated chart recorder in the Control Room. (RE: NSMs ON-1/2/32401). The range of
2 the readouts is 50 to 700°F which Duke considers adequate for the intended monitoring function. Also
2 note, this range is in compliance with the recommendations of Revision 3 to RG 1.97. Control room
2 display is through the inadequate Core Cooling Monitoring system.

2 7.5.2.17 Reactor Building Sump Water Level Narrow Range

2 Two channels of instrumentation monitor both the Normal Sump Level (0 to 2 feet, approximately 350
2 gallons) and the Emergency Sump Level (0 to 3 feet, approximately 4000 gallons). This instrumentation
2 is environmentally qualified and powered from safety grade emergency power buses. Qualified backup
2 indication is provided by the Wide Range Sump Level instrumentation.

2 (Re: FSAR 3.4.1.1.2, "Flood Protection Measures Inside Containment").

2 (RE: NSM ON-2248)

2 7.5.2.18 Reactor Building Sump Water Level

2 Two redundant QA Condition 1 channels of level instrumentation are provided for measuring reactor
2 building sump water level from the bottom of the Reactor Building to approximately five feet above the
2 maximum flood elevation which exceeds the 600,000 gallon level. The indicated range is 0 to 15 feet.
2 Redundancy/diversity is provided by the Borated Water Storage Tank Level and the Narrow Range Sump
2 Level indicators. The instrumentation channels are environmentally and seismically qualified and powered
2 by safety grade emergency power buses.

2 (Re: FSAR 3.4.1.1.2, "Flood Protection Measures Inside Containment").

2 7.5.2.19 Reactor Building Pressure

2 Two redundant QA Condition 1 channels of instrumentation are provided for monitoring Reactor
2 Building Pressure. The instrumentation channels are environmentally and seismically qualified and
2 powered by safety grade emergency power buses. The indicated range is -5 to 175 psig with the reactor
2 building design pressure being 59 psig. This instrumentation range covers nearly 99% of the
2 recommended Regulatory Guide 1.97, Revision 2, range of 10 psig to 3 times the design pressure (177
2 psig). Duke considers the indicated range adequate for the intended accident monitoring function.

2 7.5.2.20 Reactor Building Isolation Valve Position

9 All electrically controlled reactor building isolation valves that are active to close for containment isolation
9 have control switches on the main control boards. Actual valve position is provided by QA Condition 1
2 limit switches on the valves which operate both Closed-Not Closed, and Open-Not Open control switch
2 indicating lights. These valves are powered by safety grade emergency power buses. Additional indication
2 is provided by the computer. Redundancy is not necessary on a per valve basis since redundant barriers
2 are provided for all fluid penetrations as discussed in the Oconee FSAR Section 6.2.3.2, "System Design."
2 Environmental qualification of the limit switches is described in the Oconee FSAR section 3.10, "Seismic
2 Qualification of Instrumentation and Electrical Equipment" and the Oconee Nuclear Station Seismic
2 Design Criteria (OSDC-0193.01-00-00001).

2 7.5.2.21 Radiation Level in Primary Coolant

2 Oconee has one channel of primary coolant radiation level instrumentation which monitors the Reactor
2 Coolant and Letdown Line and is isolated upon ESF actuation signal. The channel is powered from a
2 highly reliable battery backed bus. The indicated range is 10^1 to 10^6 counts per minute which covers
2 reactor coolant concentration of approximately 10^{-3} uCi/ml to 10^3 uCi/ml (see the Oconee FSAR,
2 Section 11.5, "Process and Effluent Radiological Monitoring and Sampling Systems"). Although the
2 Regulatory Guide 1.97, Revision 2, recommended range of 1/2 the Technical Specification limit to 100
2 times the Technical Specification limit is not met, the indicated range is considered adequate for the
2 intended monitoring function.

2 This monitor was not installed to quantify accident conditions nor as a Category 1 instrument. It is
2 isolated following an accident. The level of environmental qualification provided for this instrumentation
2 is consistent with its performance expectations and meets the recommendations of Category 3 in Duke's
2 interpretation of RG 1.97, Rev. 2. Information for this variable is obtained by sampling and analysis
2 which is considered adequate for the intended monitoring function.

2 Section II.B.3 of NUREG-0737 required that the capability exist at each nuclear plant to sample the RCS
2 to access the magnitude of fuel failures during post-accident conditions. As such, this method should be
2 the primary means of determining clad breach. (Re: FSAR 9.3.6.1, "Post-Accident Liquid Sampling
2 System")

9 7.5.2.22 Accident Sampling Capability, Primary Coolant, Primary Coolant Sump,
9 Containment Air

2 The existing design of the sampling system for the primary coolant, the Reactor Building sump and
2 Reactor Building air allows samples to be taken for laboratory analysis. Samples from other plant
2 systems including various auxiliary building sumps can be obtained from sample points on system piping
2 and/or storage tanks. Capabilities for making the recommended measurements (some use diluted samples)
2 are provided. Detailed information concerning the Post-Accident Sampling Systems and the laboratory
2 capabilities available at Oconee is described in the NUREG 0737, II.B.3 Post-Accident Sampling System
2 (PASS) response.

2 The use of diluted samples is in part for maintaining personnel exposures ALARA and is within the
2 guidelines provided in NUREG 0737 and its clarifications. Although Regulatory Guide 1.97, Revision 2
2 recommends a range of 10 uCi/gm to 10 Ci/gm or TID 14844 source term in coolant volume grab
2 samples. Duke considers the use of diluted samples in compliance with Regulatory Guide. The Criterion
2 5 of NUREG 0737 allows 96 hours to perform a chloride analysis which will be met by Duke Power.
2 The 24 hour time limit applies only to BWR's on sea or brackish water sites, and plants which use sea or
2 brackish water in essential heat exchangers. The existing chloride measuring capabilities are considered
2 adequate by Duke. Further discussion of these subjects is contained in the PASS response referenced
2 above.

2 (Re: FSAR 9.3.6.1, "Post-Accident Liquid Sampling System," FSAR 9.3.6.2, "Post-Accident
2 Containment Air Sampling System").

2 7.5.2.23 Reactor Building Area Radiation - High Range

2 Oconee has two redundant QA Condition 1 channels of Reactor Building high range radiation monitoring
2 instrumentation. Each channel is powered by safety grade emergency power. The indicated range is 1 to
9 10^8 R/hr. Diversity is provided by portable instrumentation or by sampling and analysis. The
2 instrumentation is seismically and environmentally qualified.

2 7.5.2.24 Airborne Process Radiation Monitors

2 Airborne process radiation monitors exist for monitoring ventilation exhausts and the condenser air
2 ejector exhaust (see Oconee FSAR, Section 11.5, "Process and Effluent Radiological Monitoring and
2 Sampling Systems" and Table 11-7). However, in accordance with RG 1.97, Rev. 2 these individual
2 airborne process radiation monitors are not required for accident monitoring due to the fact that
2 ventilation systems and the condenser air ejector exhaust to the common unit vent (See Oconee FSAR,
2 Section 7.5.2.52, "Unit Vent Radioactive Discharge Monitors").

2 7.5.2.25 Area Radiation

2 Oconee has an extensive Area Radiation Monitoring System installed for personnel protection. Channel
2 detector locations were selected based on areas normally having free access and low radiation dose rates
2 with the potential of having abnormal radiation levels. These channels have an indicated range of 10^{-1} to
2 10^7 mr/hr. Redundant indication can be provided by portable instrumentation. The channels are

2 powered by a highly reliable non load shed power bus capable of receiving power from the on-site
2 emergency power sources. See the Oconee FSAR, Section 12.3.3, "Area Radiation Monitoring System."

2 The environmental qualification of some of the instrumentation is not in compliance with the
2 recommendations of Regulatory Guide 1.97, Revision 2. However, the qualification is within the guidance
2 provided for Category 3 instrumentation which Duke considers adequate for the intended monitoring
2 function. Also note, this is in compliance with the recommendations of RG 1.97, Rev. 3. Continuous
2 recording is not required for the intended monitoring function.

5 7.5.2.26 Decay Heat Cooler Discharge Temperature

2 Each train of the Oconee LPI system contains instrumentation to monitor decay heat cooler discharge
2 temperature which is referred to in Regulatory Guide 1.97, Revision 2, as RHR Heat Exchanger Outlet
2 Temperature. The range for this instrumentation is 0 to 400°F, and the power supply is a highly reliable
2 battery backed control bus. Each train is environmentally qualified per the IEB-79-01B submittal
2 methodology and envelopes the Regulatory Guide 1.97, Rev. 2 range of 32° to 350°F.

5

2 7.5.2.27 Core Flood Tank Level

2 Oconee has two channels of tank level instrumentation on each of the two core flood tanks. Power for
8 these channels is provided by highly reliable battery backed buses. The indicated range for Units 1, 2 and
8 3 is 1.5 to 14 feet which corresponds to approximately 22% to 83% of the core flood tank volume. The
2 equipment is located in a harsh environment.

2 The range and environmental qualification of this instrumentation is not in total compliance with the
2 recommendations of RG 1.97, Rev. 2, which recommends a range of 10% to 90% volume and Category
2 2 classification.

2 The primary function of this instrumentation is to monitor the pre-accident status of the core flood tanks
2 to assure that this passive safety system is prepared to serve its safety function. The indicated range
2 envelopes the Technical Specification level requirements and Duke Power considers the range adequate to
2 meet the intended monitoring function. This instrumentation plays no significant role in the subsequent
2 management of an accident. Therefore, Core Flood Tank Level is not a key variable for accident
2 monitoring and is considered to be Category 3 instrumentation. The level of environmental qualification
2 provided for the instrumentation in this system is consistent with the performance expectations of the
2 system and meets the recommendations of Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

2 7.5.2.28 Core Flood Tank Pressure

2 Oconee has two channels of core flood tank pressure instrumentation on each of the two core flood tanks.
2 Power for these channels is provided by highly reliable battery backed buses. The indicated range is 0 to
2 700 psig. The tanks are pressurized to 600 psig under normal operating conditions.

2 The primary function of this instrumentation is to monitor the pre-accident status of core flood tanks to
2 assure that this passive safety system is prepared to serve its safety function. This instrumentation plays
2 no significant role in the subsequent management of an accident. Therefore, Core Flood Tank Pressure is
2 not a key variable for accident monitoring and is considered to be Category 3 instrumentation. The
2 installed system meets the Duke interpretation of Category 3 recommendations. Regulatory Guide 1.97,
2 Revision 2, classifies this variable as Category 2.

The range of this instrumentation is not in total compliance with the recommended 0 to 750 psig range of Regulatory Guide 1.97, Revision 2. However, the indicated range covers approximately 0 to 117% of the operating pressure of the tanks. Because the purpose of this variable is to monitor and maintain Core Flood Tank pressure during normal operation to Technical Specification (TS) limits, the range of this variable should provide some margin above that TS limit. Since the Oconee TS limit is 600 ± 25 psig, a high range value of about 700 psig will provide greater than 10% excess range measurement capability and will therefore be sufficient. Duke Power considers the instrumentation adequate for the intended monitoring function.

7.5.2.29 Core Flood Tank Isolation Valve Position

The core flood tank isolation valves are provided with control switches on the main control board. During normal plant operation, power is removed from the valve operators to prevent a spurious signal from inadvertently closing the valves. The indicating lights are powered from a separate highly reliable battery backed bus and give actual valve position of both Closed-Not Closed and Open-Not Open. Environmentally qualified limit switches are provided for the core flood tank isolation valves.

7.5.2.30 Boric Acid Charging Flow

Oconee NSSS does not include a charging system as part of the Emergency Core Cooling System (ECCS). Flow paths from the ECCS to the RCS include high pressure injection (HPI) and low pressure injection (LPI) with the BWST or the RB Sump as the suction source, and the Core Flood Tank injection. HPI and LPI flow rates are monitored, and BWST, Reactor Building Sump, and Core Flood Tank levels are monitored by RG 1.97 variables. Therefore, Boric Acid Charging Flow monitoring is not applicable to the operation of the ECCS and is not a Type D variable for Oconee.

7.5.2.31 Reactor Coolant Pump Status

The indicated range for RCP motor current is from 0 to 1200 amps. The instrumentation derives power from the monitored source and is adequate for the intended monitoring function.

7.5.2.32 Power Operated Relief Valves Status

An acoustical leak detection monitoring system is the primary instrumentation for determining PORV position. It is a single channel system powered from a highly reliable battery backed bus. It provides the operator with positive indication of valve position by indicating fractional flow through the valve in ten steps from 0.01 to 1.0. Backup indication of PORV position is provided by limit switch operated indicating lights and PORV outlet temperature indication. The system was specified and is rated to operate in all environmental conditions for its location.

(RE: NSMs ON-1/2/32594)

7.5.2.33 Primary System Safety Relief Valve Positions (Code Valves)

Acoustical leak detection monitoring systems are the primary instrumentation for determining code valves position. Each code valve has a single channel system powered from highly reliable battery backed bus. It provides the operator with positive indication of valve position by indicating fractional flow through the valve in ten steps from 0.01 to 1.0. Backup indication of code valve position is provided by valve outlet temperature indication. The system was specified, and is rated to operate in all environmental conditions for its location.

(RE: NSMs ON-1/2/32594)

2 7.5.2.34 Pressurizer Heater Status

2 Control indicating lights are used for indication of the ON/OFF status of the pressurizer heater groups.
2 Indicating lights are powered by highly reliable battery backed busses. This monitoring instrumentation is
2 located in a mild environment.

2 ON/OFF status of the pressurizer heaters provides the operator adequate information for Design Basis
2 events. Additionally, RCS pressure can be monitored to determine the effectiveness of the heaters to
2 maintain system pressure. Duke feels that this is adequate for the intended monitoring function, and that
2 monitoring of electric current per Regulatory Guide 1.97, Revision 2, recommendations is not necessary.

2 7.5.2.35 Quench Tank Level

2 The indicated range of Quench Tank Level is from 0 to 125″ corresponding to tank volume of
2 approximately 15-96%. This range is not in complete compliance with RG 1.97, Rev. 2, which
2 recommended top to bottom tank monitoring, however, the upper range meets the intended monitoring
2 function. No useful information would be gained by measuring tank volume from 0-15%. Normal level
2 (pre-accident) is maintained above 15% and post-accident condition will only increase tank level.
2 Therefore, the existing range is adequate for the intended monitoring function.

2 7.5.2.36 Quench Tank Temperature

8 The indicated range of the Quench Tank temperature is from 50° to 350°F. The design temperature of the
2 Quench Tank is 300°F which is greater than the maximum temperature reached in the tank during a
2 design transient. The tank design pressure is 55 psig, which is greater than the calculated pressure of
2 approximately 50 psig (rupture disc pressure) attained after the most severe transient. The saturation
2 temperature for 50 psig is 297°F. Thus, the indicated range of 50°-350°F will adequately measure the
2 expected maximum temperature as well as saturation temperature for the Quench Tank.

2 (RE: NSMs ON-1/2/32593)

2 7.5.2.37 Quench Tank Pressure

9 The indicated range of the Quench Tank pressure is from 0 to 60 psig. The tank rupture disc is designed
9 to relieve at 55 psig, and the tank design pressure is 55 psig. Therefore, the installed instrumentation is
2 adequate for the intended monitoring function.

2 7.5.2.38 Main Steam Safety Valve Position

2 This variable is not monitored directly. The positions of the Main Steam Safety Valves (MSSV) are not
2 required to mitigate the consequences of a design basis accident. Direct indication of safety valve position
2 is not provided but indirect indication is provided via control room indication of steam generator pressure.
2 During Duke's Control Room Design Review, a specific Task Analysis Evaluation of MSSV indication
2 was undertaken. This evaluation dealt with steam leak transients with and without MSSV indication. As
2 a result of this evaluation, direct MSSV indication was found not necessary. Also, sound emitted from
2 the valves provides an audible indication to the operators when the valves lift. Duke feels that this is
2 adequate indication for the intended monitoring function.

2 7.5.2.39 Main Feedwater Flow

7 Each feedwater line has three main feedwater flow transmitters. The indicated range for this variable is 0
8 to 6.0×10^6 lbs/HR which corresponds to 0 to 111% of design flow.

2 7.5.2.40 Emergency Feedwater Flow

2 Oconee has four QA Condition 1 flow transmitters, two per steam generator monitoring Emergency
2 Feedwater Flow from all EFDW pumps to each steam generator. The indicated range for this variable is
2 0 to 1200 GPM which corresponds to a range of 0 to 115% design flow. This instrumentation is powered
2 from a safety grade emergency power source. The flow transmitters are located in a mild environment.
2 Seismic qualification methodology for these transmitters is as described in the Oconee FSAR, Section
2 3.10, "Seismic Qualification of Instrumentation and Electrical Equipment." The indicators are located in
2 the control room which is classified as a mild environment. Emergency Feedwater flow is recorded on a
2 dedicated chart recorder in the Control Room for EFW flow to each steam generator.

2 7.5.2.41 Reactor Building Fan Heat Removal

2 The key variable for monitoring Reactor Building Cooler performance is Reactor Building Pressure
9 instrumentation which is Category 1. Backup instrumentation includes Nuclear Safety Related indication
2 of each Reactor Building Cooler Fan motor starter status (high and low speed lights), each Fan motor
2 starter status on the computer, indication of each Fan motor amperage, indication of inlet and outlet
2 cooling water flow to each cooler, and inlet and outlet air temperature indication for each cooler. All of
2 the above indications are provided in the Control Room. The installed instrumentation is adequate for
2 the intended monitoring functions. For backup indications, the level of environmental qualification
2 provided for the instrumentation is consistent with the performance expectations of the instrumentation
2 and meets the recommendations of Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

2 7.5.2.42 Reactor Building Air Temperature

9 Thirteen dual element thermocouples are provided to measure Reactor Building air temperature on Units
9 1 & 2. Twelve dual element thermocouples are provided on Unit 3. One element of each T/C provides an
2 input to the plant computer and the second element of each T/C provides an input to the multipoint
7 recorder. The plant computer displays a range of 0 to 400°F, the recorder displays a range of 0 to 300°F.
2 The plant computer and the recorder are powered by highly reliable battery backed busses.

2 The displayed ranges are adequate for the intended monitoring function. The worst case DBA
2 temperature in the Reactor Building is 286°F. For accidents in which harsh RB environments are a result,
2 pressure and temperature are coupled such that as RB pressure is reduced the temperature is also reduced.
2 Therefore, RB pressure is considered the priority variable with temperature as a Category 3 backup
2 variable. The level of environmental qualification provided for this instrumentation is consistent with its
2 performance expectations and meets the recommendations of Category 3 in Duke's interpretation of RG
2 1.97, Rev. 2.

2 7.5.2.43 Makeup Flow

2 The existing instrumentation for this variable provides continuous monitoring of reactor coolant makeup
2 flow. The loop range is 0 to 160 gallons per minute which encompasses the Regulatory Guide 1.97,
8 Rev.2 criteria of 0-110% of design flow. Design flow is 35 GPM. The instrumentation is located in a
2 mild temperature environment.

2 The transmitter for this variable is not rated to withstand the anticipated maximum design basis accident
2 radiation dose for the installed location. The installed instrumentation is adequate for the intended
2 monitoring function. For accidents in which harsh environments are a result, the portion of the system
2 containing this instrumentation is not required for the mitigation of these accidents and is automatically
2 bypassed upon an ESF Actuation. Therefore, Makeup Flow is not a key variable for accident monitoring
2 and is considered to be Category 3, instrumentation. The level of environmental qualification provided

2 for the instrumentation in this system is consistent with the performance expectations of the system and
9 meets the recommendations of Category 3 in Duke's interpretation of RG 1.97, Rev. 2.

2 7.5.2.44 Letdown Flow

2 The existing instrumentation for this variable provides continuous monitoring of reactor coolant letdown
2 flow. The loop range is 0 to 160 gallons per minute which envelopes the Regulatory Guide 1.97, Rev. 2
2 criteria of 0-110% of design flow. Design flow is 70 GPM. This instrument loop is powered from a
2 highly reliable battery backed bus. The instrumentation is located in a mild temperature environment.

2 The transmitter for this variable is not rated to withstand the anticipated maximum design basis accident
2 radiation dose for the installed location.

2 The installed instrumentation is adequate for the intended monitoring function. For accidents in which
2 harsh environments are a result, the portion of the system containing this instrumentation is not required
2 for the mitigation of these accidents and is automatically isolated upon an ESF Actuation. Therefore,
2 Letdown Flow is not a key variable for accident monitoring and is considered to be Category 3
2 instrumentation. The level of environmental qualification provided for the instrumentation in this system
2 is consistent with the performance expectations of the system and meets the recommendations of Category
2 3 in Duke's interpretation of RG 1.97, Rev. 2.

2 7.5.2.45 Letdown Storage Tank Level

2 The existing instrumentation for this variable provides continuous monitoring of the letdown storage tank
2 level. The loop range is 0 to 100 inches which covers the linear portion of the tank (approximately 16 to
2 84% of tank volume). This instrument loop is powered from a highly reliable battery backed bus. This
2 instrumentation is located in a mild environment.

2 Minimum and maximum letdown storage tank levels are maintained within the range of the instrument.
2 Extending the range into the domed portions of this tank would result in nonlinear readings at each
8 extreme of the scale. The installed range is adequate for measuring letdown storage tank level. The
8 installed instrumentation is adequate for the intended monitoring function. This tank is not required to
8 be utilized during an accident. As a commitment to the NRC, Duke is voluntarily upgrading this LDST
8 level instrumentation to Category 2 Nuclear Safety Related (QA-1). This change was performed on Unit 3
8 during the 3EOC17 refueling outage, and will be implemented on the other units in subsequent outages.
8 This upgraded instrumentation is also adequate to perform the intended monitoring function. (Ref NSM
8 x-2885)

2 7.5.2.46 Low Pressure Service Water Temperature to ESF System

2 The Oconee system for providing cooling water to ESF components is the Low Pressure Service Water
9 System (LPSW). The temperature of LPSW is essentially the same as the temperature of Lake Keowee at
9 the CCW pump suction. There is no control over the temperature of the LPSW; therefore, there is no
2 need to indicate the LPSW temperature in the control room since no operator action is taken based on
2 this temperature and, by design, no useful information would be provided to the operator by such
2 instrumentation.

2 7.5.2.47 Low Pressure Service Water Flow to ESF Systems (Pressure)

2 The Oconee system for providing cooling water to ESF components is the Low Pressure Service Water
2 System (LPSW). Primary indication of proper LPSW system and pump operation is line pressure
2 measured in each of the two LPSW headers. The indicated range is 0 to 100 psig for a system design

4 pressure of 100 psig. These instruments are located in a mild environment and powered by a highly
2 reliable battery backed source which meets Category 2 requirements. Additional instrument loops provide
2 backup indication in the Control Room of proper system operation. These include LPSW pump motor
2 amperage, valve position indication on valves operated in the control room, inlet and/or outlet cooling
2 water flow for certain ESF coolers, and flow and pressure alarms.

2 LPSW header pressure is a valid measurement of system and pump operation and Duke considers the
2 existing indications to meet the intent of Regulatory Guide 1.97, Rev. 2. For backup variables, a design
2 qualification of Category 3 is adequate for the intended monitoring functions and consistent with the
2 performance expectations of the instrumentation.

4 (RE: NSMs ON-1/3/32590)

2 7.5.2.48 RC Bleed Holdup Tank Level

2 The indicated range for this variable is 0 to 180 inches for the RC Bleed Holdup tank. This level
2 indication corresponds to a tank volume of approximately 1% to 99%. Although the range is not in
2 complete compliance with the recommendation of RG 1.97, Rev. 2 (top to bottom), the tap to tap range
2 of the installed instruments is adequate to provide tank level information for all design basis events. Duke
2 considers the installed instrumentation adequate for the intended monitoring function.

2 7.5.2.49 Waste Gas Decay Tank Pressure

2 Oconee utilizes two tanks per unit for radioactive waste gas storage. The maximum operating pressure for
2 these tanks is approximately 100 psig (per Oconee FSAR, Section 11.3, "Gaseous Waste Management
2 Systems"). The indicated range is 0 to 150 psig for each tank, which is adequate for the intended
2 monitoring function.

9 7.5.2.50 Emergency Ventilation Valve Position

2 There are three Emergency Ventilation Systems at Oconee; Reactor Building Purge, Penetration Room
2 Ventilation, and Reactor Building Cooling. Each system has indication that the required emergency
2 alignment has been achieved in the control room.

9 For the Reactor Building Purge System direct indication of containment isolation valves position is
9 provided. The in-containment isolation valves (PR-1, 6) are MOVs whose position indication is provided
9 by internal limit switches. These valves are not in the EQ program because they are racked-out during
9 normal operation and are not required to function during a design basis event. This instrumentation is
9 powered from safety grade emergency power. The out-of-containment isolation valves (PR-2, 5) are
9 AOVs and positive indication is provided by limit switches. Positive indication of these valves is required
9 per RG 1.97 (PAM). Therefore environmental qualification is provided for these limit switches. This
9 instrumentation is powered from safety grade emergency power.

2 For the Penetration Room Ventilation System, positive indication of proper system operation is provided
2 by the Penetration Room Pressure Instrumentation. This instrumentation is pneumatic and is supplied
2 by normal Station Air System. The Unit 1 and 2 instruments are located in mild environments; however,
2 the Unit 3 instrumentation may be in a harsh environment and qualification documentation may not be
2 available.

2 For a description of the instrumentation required to determine proper operation of the Reactor Building
9 Cooling System see UFSAR Section 7.5.2.41, "Reactor Building Fan Heat Removal."

2 7.5.2.51 Emergency Power System Status

2 All safety-grade emergency or battery backed control busses have undervoltage alarms in the Control
2 Room with local diagnostic capabilities to enable an expedient assessment of abnormal situations. In
2 addition, the 125 VDC distribution centers have analog indicators of voltage level in the Control Room.
2 All of the Control Room alarms are on highly reliable battery backed busses. All of the sensing relays
2 and alarm electronics are located in a mild environment. See FSAR Chapter 8, "Electric Power."

2 7.5.2.52 Unit Vent Radioactive Discharge Monitors

2 Oconee has a normal range, high range and high-high range channel of unit vent radioactivity
8 instrumentation. These channels are powered from a highly reliable non load shed power bus. The
2 indicated range is 1 to 10^8 R/hr gross gamma for the high-high range monitor which envelopes the upper
8 end of the recommended range. The indicated range is 10 to $1E^7$ cpm for the high range channel and 10
8 to $1E^7$ cpm for the normal range channel. The combined ranges of these monitors meet the requirements
8 of Regulatory Guide 1.97, Rev.2. This instrumentation is installed in a mild environment.

2 7.5.2.53 Unit Vent Flow

2 The installed instrumentation indicates flow in the unit vent stack over the range of 0 to 110% of design
9 flow. The design flow for the Unit 1 stack is 97,262 SCFM (98,880 for Unit 2; 114,506 for Unit 3). The
9 indicator and recorder, Units 1, 2 and 3 respectively, actual dual ranges are the following:

9 Unit 1&2 - 0 to 60 x 10^3 SCFM
9 0 to 120 x 10^3 SCFM

9 Unit 3 - 0 to 65 x 10^3 SCFM
9 0 to 130 x 10^3 SCFM

2 The primary instrument loop which contains the transmitter, the plant computer and the retransmitter is
2 powered by a highly reliable battery backed bus. The secondary instrument loop contains the
2 retransmitter, indicator and recorder, and is powered by a highly reliable auxiliary bus. The
2 instrumentation is located in a mild environment and envelopes the Regulatory Guide 1.97, Rev. 2 range
2 criteria of 0 to 110% of design flow.

2 7.5.2.54 Main Steam Line Radiation Monitors

2 Area radiation monitors are located adjacent to the main steam lines to detect radioactivity emitted from
3 main steam. The monitors for all 3 units are located upstream of the main steam relief valves.
3 Correlation curves allow conversion of the monitor readings in mR/hr to µCi/cc. The indicated range for
3 the monitors is 10^{-2} to 10^7 mR/hr. The monitors are powered from a highly reliable non load shed power
3 bus capable of receiving power from the on-site emergency power sources. This instrumentation is rated
2 to withstand the environmental conditions that would exist during accidents in which it is intended to
2 operate. A steam line break in the vicinity of this instrumentation may cause the environment to exceed
2 the rated temperature, however, the instrument is not required to remain operational for this event.

3

2 7.5.2.55 Wind Direction

2 Oconee has two channels of wind direction instrumentation. The indicated range is 0 to 540°. Wind
7 direction is a Regulatory Guide 1.97 Category 3 Type E Variable. The range and accuracy of the installed
7 instrumentation is adequate for its intended purpose.

7

2 7.5.2.56 Wind Speed

7 Oconee has two channels of wind speed instrumentation. The indicated range is 0 - 60 mph. Wind Speed
7 is a Regulatory Guide 1.97 Category 3 Type E Variable. The range and accuracy of the installed
7 instrumentation is adequate for its intended purpose.

2 7.5.2.57 Atmospheric Stability

2 The indicated range for atmospheric stability is -4° to 8°C for 44.7 meter interval. Loop accuracy is at
2 least + 0.15°C. This range is adequate for Oconee site meteorological conditions.

3 7.5.2.58 Low Pressure Service Water Flow to Low Pressure Injection
3 Coolers

3 Two QA Condition 1 instrumentation channels are provided (one per train) for post accident monitoring
3 of Low Pressure Service Water (LPSW) flow to the Low Pressure Injection (LPI) coolers in response to
9 Regulatory Guide 1.97. Each instrument channel is seismically qualified and powered from a safety grade
9 power source. Each instrument channel signal inputs to a qualified indicator and to the plant computer
9 via a qualified signal isolator. These channels monitor LPSW flow to the LPI Coolers over a range of
3 0-8000 gpm which envelopes the 0-110% of design flow criteria for Regulatory Guide 1.97.

3 Two non-safety instrument channels are provided, one per train, for indication of LPSW flow to LPI
8 Cooler and control of valves LPSW-251 and 252. Each instrument signal inputs to a controller which
3 monitors flow and valve control. These channels monitor LPSW flow to the LPI Cooler over a range of
3 0-6000 gpm. These instrument channels are not required for Regulatory Guide 1.97 and are used for
3 normal operation.

3 LPSW flow to LPI Coolers is a Type A variable at Oconee because the operator relies on this
3 information following a design basis event (LOCA) to throttle LPSW flow to LPI Coolers to maintain
3 proper flow balance in the LPSW System.

8

8 7.5.2.59 Essential Siphon Vacuum Tank Pressure (Vacuum)

8 The instrumentation for this variable provides continuous display of Essential Siphon Vacuum (ESV)
8 Tank Pressure. One instrument channel is provided for each train of ESV tank. The ESV system on a per
8 unit basis consists of three pumps and two tanks. Each train consists of one tank and one pump. The
8 third ESV pump serves as an in-place spare pump which can be aligned to either train. The
8 instrumentation provides control room indication of tank vacuum from 30 In Hg to 0 In Hg. The
8 instrumentation is seismically qualified in accordance with the Oconee licensing basis as specified in the
8 Oconee UFSAR and Duke Power Seismic Design Criteria (OCSD-0193.01-00-0001). The instrumentation
8 is located in the ESV building which is considered a Mild Environment. The installed equipment meets

8 the requirements of RG 1.97, Rev 2 for Type D, Category 2 nuclear safety related (QA-1) instrumentation
8 as described in Section 7.5, "Display Instrumentation."

8 This instrumentation monitors the Essential Siphon Vacuum Tanks for operation to provide information
8 (two indicators, two computer alarms, and two annunciator alarms, all one per tank) to indicate the
8 operation of the system in the event it is needed to mitigate the consequences of the design basis accident
8 (LOCA/LOOP).

8 **7.5.2.60 Essential Siphon Vacuum Tank Water Level**

8 The instrumentation for this variable provides continuous local display of Essential Siphon Vacuum Tank
8 Water level. One instrument is provided on each train of ESV tank. The level gage is physically located on
8 the tank. The ESV system for each unit consists of three full capacity pumps and two tanks. Each train
8 consists of one tank and one pump. The instrumentation range (0-24 inches) provides local indication of
8 any accumulated water in the ESV Tanks. Manual action can be taken to drain the tanks as required. The
8 instrumentation is seismically qualified in accordance with the Oconee licensing basis as specified in the
8 Oconee UFSAR and Duke Power Seismic Design Criteria (OCSD-0193.01-00-0001). The instrumentation
8 is located in the ESV building which is considered a Mild Environment. The installed equipment is
8 adequate for its intended monitoring function and meets the requirements of RG 1.97, Rev. 2 for Type D,
8 Category 2 nuclear safety related (QA-1) variables instrumentation as described in Section 7.5, "Display
8 Instrumentation."

8 This variable monitors the Essential Siphon Vacuum Tanks for operation to provide local indication
8 regarding the operation of the system in the event it is needed for continued post accident mitigation of
8 the consequences of the design basis accident (LOCA/LOOP).

8 **7.5.2.61 Siphon Seal Water Flow to Essential Siphon Vacuum Pumps**

8 The instrumentation for this variable provides continuous local display of Siphon Seal Water (SSW) flow
8 to the Essential Siphon Vacuum pumps as well as a signal to the plant computer for display in the control
8 room. One instrument is provided on each SSW supply to an ESV pump. There are three ESV pumps
8 per unit. A total of nine instruments are provided for the nine ESV pumps. A bargraph indicator is
8 located on the local panel in the ESV Building for each Unit's three pumps. The ESV system consists of
8 three pumps and two tanks. Each ESV train consists of one tank and one pump. The third pump is an
8 installed spare. The instrumentation is seismically qualified in accordance with the Oconee licensing basis
8 as specified in the Oconee UFSAR and Duke Power Seismic Design Criteria (OCSD-0193.01-00-0001).
8 The instrumentation is located in a Mild environment. The installed equipment meets the requirements of
8 RG 1.97, Rev. 2, Type D, Category 2 nuclear safety related (QA-1) instrumentation as described in
8 Section 7.5, "Display Instrumentation."

8 The range (0 to 15 Gallons per Minute (GPM)) and the qualification requirements of the SSW flow to
8 ESV pumps instrumentation is in compliance with the recommendations of RG 1.97, Rev. 2 for Type D
8 variables. This variable monitors the Siphon Seal Water flow to the Essential Siphon Vacuum Pumps to
8 provide information relative to the operation of the ESV system in the event it is needed for continued
8 post accident mitigation of the consequences of the design basis accident (LOCA/LOOP).

7.6 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

7.6.1 REGULATION SYSTEMS

Reactor output is regulated by the use of movable control rod assemblies and soluble boron dissolved in the coolant. Control of relatively fast reactivity effects, including Doppler, xenon, and moderator temperature effects, is accomplished by the control rods. The control response speed is designed to overcome these reactivity effects. Relatively slow reactivity effects, such as fuel burnup, fission product buildup, samarium buildup, and hot-to-cold moderator reactivity deficit, are controlled by soluble boron.

Control rods are normally used for control of xenon transients associated with normal reactor power changes. Chemical shim shall be used in conjunction with control rods to compensate for equilibrium xenon conditions. Reactivity control may be exchanged between rods and soluble boron consistent with limitations on power peaking.

9 Reactor regulation is a composite function of the Integrated Control System and Control Rod Drive System. Design data for these subsystems are given in the following sections.

9 7.6.1.1 Control Rod Drive System

9 The Control Rod Drive System (CRD) includes drive controls, power supplies, position indicators, operating panels and indicators, safety devices, and enclosures.

7.6.1.1.1 Design Basis

9 The Control Rod Drive System design bases are categorized into safety considerations, reactivity rate limits, startup considerations, and operational considerations.

7.6.1.1.2 Safety Considerations

The control rod assemblies (CRA) are inserted into the core upon receipt of protective system trip signals. Trip command has priority over all other commands.

9 No single failure shall inhibit the protective action of the Control Rod Drive System.

7.6.1.1.3 Reactivity Rate Limits

The speed of the mechanism and group rod worth provide the reactivity change rates required. For design purposes, the maximum rate of change of reactivity that can be inserted by any group of rods has
9 been set at a conservative value used within the Chapter 15 Section 15.3, "Rod Withdrawal At Power
9 Accident" and Section 15.2, "Startup Accident." The drive controls, i.e., the drive mechanism and rods combination, have an inherent speed-limiting feature.

6

7.6.1.1.4 Startup Considerations

9 The Control Rod Drive System design bases for startup are as follows:

Reactor regulation during startup is a manual operation.

4 Control rod "out" motion is inhibited when a high startup rate in the wide range is detected.

7.6.1.1.5 Operational Considerations

9 For operation of the reactor, functional criteria related to the control rod drive system are:

CRA Positioning

9 The Control Rod Drive System provides for controlled withdrawal, controlled insertion, and holding of the control rod assemblies (CRA) to establish and maintain the power level required for a given reactor coolant boron concentration.

Position Indication

Continuous rod position indication, as well as full-in and full-out position indication, are provided for each control rod drive.

System Monitoring

9 The Control Rod Drive System design includes provisions for routinely monitoring conditions that are important to safety and reliability.

7.6.1.1.6 System Design

9 The Control Rod Drive System provides for withdrawal and insertion of the control rod assemblies to maintain the desired reactor output. This is achieved either through automatic control by the Integrated Control System discussed in Section 7.6.1.2, "Integrated Control System" or through manual control by the operator. As noted previously, this control compensates for short term reactivity changes. It is achieved through the positioning in the core of sixty-one control rod assemblies and eight axial power-shaping rod assemblies. The sixty-one rods are grouped for control and safety purposes into seven groups. Four groups function as safety rods, and three groups serve as regulating rods. An eighth group serves to regulate axial power peaking due to xenon poisoning. Seven of the eight groups may be assigned from four to twelve control rod assemblies. Eight rod assemblies are used in Group 8.

Control rods are arranged into groups at the control rod drive control system patch panel. Typically,
5 thirty-six rods, including the axial power shaping rods, are assigned to the regulating groups, and
5 thirty-three rods are assigned to the safety rod groups. A typical rod grouping arrangement is shown
below:

	Safety Rods	Regulating Rods	Axial Power Shaping Rods
	Group 1 - 8	Group 5 - 12	Group 8 - 8
5	Group 2 - 8	Group 6 - 8	
5	Group 3 - 8	Group 7 - 8	
5	Group 4 - 9		

During startup, the safety rod groups are withdrawn first, enabling withdrawal of the regulating control groups. The sequence allows operation of only one regulating rod group at a time except where reactivity insertion rates are low (first and last 25 percent of stroke), at which time two adjacent groups are operated simultaneously in overlapped fashion. These insertion rates are shown in Figure 7-11.

As fuel is used, dilution of soluble boron in the reactor coolant is necessary. When Group 6 is more than 95 percent withdrawn, interlocks permit dilution. The reactor controls insert Group 6 to compensate for the reduction in boron concentration by dilution. The dilution is automatically terminated by a pre-set volume measuring device. Interlocks are also provided on Group 6 rod position to terminate dilution at a pre-set insertion limit.

7.6.1.1.7 System Equipment

9 The Control Rod Drive System consists of three basic components: (1) control rod drive motor power supplies; (2) system logic; and (3) trip breakers. The power supplies consist of four group power supplies, an auxiliary power supply, and two holding power supplies. See Figure 7-4, Figure 7-12, and Figure 7-13. The group power supplies are of a redundant six-phase half-wave rectifier design.

In each half of a group power supply, rectification and switching of power is accomplished through the use of Silicon Controlled Rectifiers (SCR). This switching sequentially energizes first two, then three, then two of the six CRA motor stator windings in stepping motor fashion, to produce a rotating magnetic field for the control rod assembly motor to position the CRA. Switching is achieved by gating the six SCR on for the period each winding must be energized. As each of the six windings utilize SCR to supply power, six gating signals are required.

5 Gating signals for the group power supplies are generated by a solid state programmer consisting of a
5 microcomputer which is programmed to accept operational commands from the input interface relays and
5 convert them to sequential outputs which cause the mechanism motors to step at the proper speed and
5 direction of rotation. The microcomputer is also programmed to provide the 3-2 hold control, which
5 ensures a two-coil hold when there are no commands. The programmer is redundant (except for
5 microprocessor power supply) thus providing separate but synchronized gating signals to the dual power
5 supply units.

Identical power supplies are used for the regulating (control) groups and for the auxiliary power supply. Each half of each group power supply is capable of driving up to 12 drive mechanisms which is the maximum number that may be in any one group. The power supplies have dual power inputs, each half fed from separate power sources and each half being capable of carrying the full load.

Unlike the control group power supplies, the holding power supply is used to maintain the safety rods fully withdrawn; consequently, switching is not required. A six-phase a-c power supply is used for this purpose. Two holding power supplies are provided. Each is rated to furnish power to one winding of 48 mechanisms; normal load would be 41 coils for each power supply.

The auxiliary power supply is used to position the safety rod groups and to provide single rod control. The safety rod groups are maneuvered with the auxiliary power supply, and then when fully positioned, are transferred to the holding busses described above. After positioning the safety rods, the auxiliary power supply is available to the regulating groups, through transfer relays, to serve either as a single rod controller, should repositioning of a single rod be necessary, or, as a spare group controller, should one of the group control power supplies require maintenance. The auxiliary power supply cannot be used to control more than one group at one time.

The system logic encompasses those functions which command control rod motion in the manual or automatic modes of operation, including group sequencing, safety and protection features, and the manual trip function. Major components of the logic system are the Operator's Control Panel, CRA position indication panels, automatic sequencer, and relay logic.

Switches are provided at the operators control panel for selection of desired rod control mode. Control modes are: (1) Automatic mode--where rod motion is commanded by the Integrated Control System; and

(2) Manual mode--where rod motion is commanded by the operator. Manual control permits operation
9 of a single rod or a group of rods. Alarm lamps on the CRD panel alert the operator to the systems status at all times. The Group 8 control rods can only be controlled manually even when the remainder of the system is in automatic control.

The sequence section of the logic system utilizes rod position signals to generate control interlocks which regulate rod group withdrawal and insertion. The sequencer operates in both automatic and manual modes of reactor control, and controls the regulating groups only. Analog position signals are generated by the reed switch matrix on the CRA, and an average group position is generated by an averaging network. This average signal serves as an input to electronic trip units which are activated at approximately 25 and at 75 percent of group rod withdrawal. Two bistable units are provided for each regulating group. Outputs of these bistables actuate "enable" relays which permit the rod groups to be commanded in automatic or manual mode.

The automatic sequencer circuit can control only rod Groups 5, 6, and 7. The safety rod groups, Groups 1 through 4, are controlled manually, one group at a time. In addition, the operator must select the safety group to be controlled and transfer it to the auxiliary power supply before control is possible. There is no way in which the automatic sequencer can affect the operations required to move the safety rods.

In addition to the sequencer, relay logic monitors are provided in the "enable" circuits which prohibit out of sequence conditions. The selection of manual control mode and sequence bypass mode functions permit intentional out-of-sequence conditions. This condition is indicated to the operator. If automatic control is selected, "sequence" operation cannot be bypassed.

"Sequence bypass" operation permits selection of any rod group or any single rod for control. It will not permit selection of more than one rod group at any given time. Motion of more than one group at any given time is also not possible when this operation is selected.

4 Inputs to the system logic from the Nuclear Instrumentation and the Integrated Control System provide interlock control over rod motion. These interlocks cause rod motion command lines and control mode selection to be inhibited.

Under certain conditions, the nuclear instrumentation generates an "out inhibit" signal. When this signal
9 is received by the Control Rod Drive System, all out command circuits are disabled, thus preventing withdrawal of all rods in either automatic or manual control.

9 Automatic operation of rods can only be commanded by the ICS when the Control Rod Drive System is in the automatic mode. These commands can only affect rod Groups 5, 6, and 7.

9 In the Control Rod Drive System, two methods of position indication are provided: an absolute position indicator and a relative position indicator. Either position signal is available to the control board indicator through a selector switch. The absolute position transducer consists of a series of magnetically operated reed switches mounted in a tube parallel to the motor tube extension. Each switch is hermetically sealed. Switch contacts close when a permanent magnet mounted on the upper end of the lead screw extension comes in close proximity.

As the lead screw (and the control rod assembly) moves, the switches operate sequentially, producing an
2 analog voltage proportional to position. Other reed switches included in the same tube with the position indicator matrix provide full-in and full-out limit indications.

The relative position transducer is a small pulse-stepping motor, driven from the power supply for the rod
2 drive motor. This small motor is coupled to a potentiometer which produces an output signal

2 proportional to rod position demand as indicated by the number of power pulses received by the rod drive
2 motor.

9 Control Rod Drive System trip breakers are provided to interrupt power to the control rod drive mechanisms. When power is removed, the roller nuts disengage from the lead screw allowing a gravity trip of the CRA.

The Group 8 drive mechanisms are modified to prevent rod drop into the core when power is removed from the stators. In this type of mechanism, the roller nuts are mechanically restrained to remain engaged with the lead screw at all times. Thus, the mechanical "trip" action has been removed from these AS PR, and they remain at the position they occupied immediately before trip was initiated. When a reactor trip is initiated, power to the Group 8 power supply is interrupted in the same manner as for the other regulating power supplies. Two series trip methods are provided for removal of power to the CRD mechanisms. First, a trip is initiated when Reactor Protective System logic interrupts power to the undervoltage (UV) coil of the main AC feeder breakers. Secondly, a trip is initiated when the Silicon Control Rectifier gating power and the DC holding power is interrupted. As parallel power feeds are provided on both holding and gating power, interruption of both feeds is required for trip action in either method of trip. Trip circuitry is shown in Figure 7-4 and Figure 7-13.

AC power feed breakers are of the three-pole, stored-energy type and are equipped with instantaneous undervoltage trip coils. Each AC feed breaker is housed in a separate metal clad enclosure. The secondary trip breakers are also of the stored-energy type with two parallel-connected instantaneous undervoltage trip coils consisting of two 2-pole breakers mechanically ganged to interrupt DC buses. All breakers are motor-driven-reset to provide remote reset capability. Each undervoltage trip coil is operated from the Reactor Protective System.

7.6.1.1.8 System Evaluation

Safety Considerations

A reactor trip occurs whenever power has been removed from the rod drive motors. The design provides two stored energy breakers which do not require power to interrupt the electrical feeds to rod drive control power supplies and a second set of circuit-interrupting devices in the series on the output of the power supplies. All devices have interrupting capacity of sufficient rating to open under any group load configuration. Reactor trip is further assured by providing series trip devices, split buses, and provisions for periodic testing. Trip redundancy is provided by series breakers while availability and testability are provided through dual power sources. Redundant power supplies permit testing of the trip action of each power-interrupting device without loss of plant availability.

Reactivity shutdown margin provided by the safety rods is assured by diversification of their power buses. This feature, as shown in Figure 7-4 utilizes four separate buses, each having a separate trip device, to power the safety rods. A failure in one bus does not reflect into the other buses, therefore, a single failure in the distribution system for the safety rods does not prevent a plant shutdown.

The minimum voltage required to hold a drive in a withdrawn position is 42 volt DC per coil (2 coil "hold" mode). The probability of an external DC source being applied to the control rod drive mechanisms downstream from the reactor trip points such that the CRA are held in their withdrawn positions after a trip is not considered credible for the following reasons:

9 1. The secondary trip devices in the Control Rod Drive System remove all DC power from the drives.

9 2. Control rod drive power cables are terminated at only three points between the Control Rod Drive System cabinets and the drive mechanisms.

Two of these terminations are made outside and inside the Reactor Building electrical penetrations
2 inside junction boxes containing only control rod drive power cables. The third termination is made in bulkhead connectors (one per drive) in the area of the reactor. The only other cables terminated in this area are the control rod drive instrumentation cables. The instrumentation cables are terminated in bulkhead connectors of a different size and configuration, therefore mismating of connectors could not be accomplished.

3. No cable splices are permitted between termination points described.

4. DC systems from the batteries at Oconee are not grounded and are equipped with ground detecting circuitry.

In summary, series redundant trip devices having adequate rating, testability and a "split bus" arrangement insure safety of reactor trip circuits.

Reactivity Rate Limits

The desired rate of change of CRA reactivity insertion and uniform reactivity distribution over the core are provided for by the control rod drive and power supply design, and the selection of rods in a group. The CRA motor, lead screw, and power supply designs are fixed to provide a uniform rate of speed of 30
2 in./min. The speed is determined by the solid state programmer, which digitally controls speed. The reactivity change is then controlled by the rod group size. To insure flexibility in this area, a patch panel has been included in the power supply to enable the interchange of rod worth between rod groups. Any rod may be patched into any group with the exception of Group 8.

Uniform and symmetrical group insertion rate is provided for by synchronous withdrawal of all rods in that group. Such synchronous withdrawal is achieved by the design of the power supply. A group power supply operates synchronously by having its load (4 to 12 CRA motor windings) connected in parallel on the output of the SCR's. As the programmer gates on the SCR's, all rods in a group have the same motor winding energized simultaneously producing synchronous motion of the entire group.

Each control rod is provided with a rod position indication monitor to sense asymmetric rod patterns by comparing the individual rod position with its group average position. When the rod moves out-of-step from its group by a preset amount, the monitor alarms the condition to the operator, the plant computer, and the ICS. Depending on the power setting and the control mode, action is initiated by the ICS to insert rods and reduce power.

Startup Considerations

The rod drive controls receive interlock signals from the ICS and nuclear instrumentation (NI). These inputs are used to inhibit automatic mode selection when a large error exists in the ICS reactor control subsystem and to inhibit out motion for high startup rates, respectively.

In addition to the startup considerations, dilution controls, to permit removal of reactor shutdown concentrations of boron in the reactor coolant, are provided. This control bypasses the normal reactor
9 coolant dilution controls, described in Section 7.6.1.1.6, "System Design," provided all safety rods are withdrawn from the core and the operator initiates a continuous feed and bleed cycle. An additional interlock on rod Group 5 inhibits the use of this circuit when rod Group 5 is more than 80 percent withdrawn.

Operational Considerations

The control rod assembly positioning system provides the ability to move any rod to any position required consistent with reactor safety. As noted in Section 7.6.1.1.8, "System Evaluation," a uniform speed is provided by the drive system. A fixed rod position when motion is not required is obtained by the power supply ability to energize two adjacent windings of the CRA motor stator. This static energizing of the windings maintain a latched stator and fixed rod position.

Position Indication

As previously described, two separate position indication signals are provided. The absolute position sensing system produces signals proportional to CRD position from the reed switch matrix located on each CRD mechanism. The relative position indication system produces a signal proportional to the number of CRD motor power pulses from a stepping motor and precision potentiometer for each CRD mechanism.

Position indicating readout devices mounted on the operator's console consist of 69 single rod position
2 meters. The operation of a selector switch permits either relative or absolute position information to be displayed on the single rod meters.

Indicator lights are provided on the single-rod meter panel to indicate when each rod is (1) fully inserted, (2) fully withdrawn, (3) under control, and (4) whether a fault is present. Indicators on the operator's console show full insertion, full withdrawal, under control, and fault indication for each of the eight control rod groups.

Failures which could result in unplanned control rod withdrawal are continuously monitored by fault detection circuits. When failures are detected, indicator lights and alarms alert the operator. Fault indicator lights remain on until the fault condition is cleared by the operator. A list of indicated faults is shown below:

1. Asymmetric rod patterns (indicator and alarm).
2 2. Sequence faults (indicator and alarm).
8 3. Trip status (indicator and alarm).
2 4. Safety rods not withdrawn (indicator only).
2 5. Rod position sensor faults.

Faults serious enough to warrant immediate action produce automatic correction commands from the fault detection circuits, and manual bypass is not possible. Status indicators on the operator's console provide monitoring of control modes.

A description of each fault detector follows:

Asymmetric Rod Monitor

Design Basis - To detect and alarm if any rod deviates from its group reference position by more than a maximum of nine inches true position.

Circuit Operation - There are 69 asymmetric rod pattern monitors, one assigned to each control rod. These monitors continuously compare the individual rod absolute position signal with the absolute group reference (average) signal. The absolute value of the difference between the two signals is computed, and if this difference is less than the maximum value set by the circuit calibration, no output results. If, however, the difference is greater than the setpoint, a relay is actuated which alarms the asymmetric condition. Two alarm channels are provided in each monitor which are identical except for the setpoints. One setpoint is calibrated for a 3-inch signal differential (maximum 7-inch true position separation) and initiates an alarm. The other setpoint is at 5-inch signal differential (maximum 9-inch true position separation) and initiates the action described below.

Corrective Action - Action taken upon detection of an asymmetric rod fault depends upon the control mode and the power level in effect at the time the fault is detected. Corrective action is the same for any asymmetric condition including "stuck-in," "stuck-out," or dropped control rods.

Detection of a 3-inch signal differential is defined as an "asymmetric rods alarm." Actuation of this alarm causes the fault indicator lamp for that rod to be energized and an alarm signal to be sent to the plant computer and annunciator.

If the condition is not corrected and the separation increases to a 5-inch signal difference, the following actions occur:

"Asymmetric fault" lamp on the operator's console is energized. If operation is in the manual control mode, operator action is required by administrative control.

7 If operation is in the automatic mode, a "runback fault" signal is sent to the Integrated Control System.
7 The ICS will impose a maximum reactor power demand of 55 percent of rated power if power is initially
7 less than 55 percent.

7 When an asymmetric fault occurs, the Control Rod Drive Control System generates an "Out Inhibit"
7 which prevents automatic rod motion that would increase reactor power. Below 60 percent reactor power
7 the ICS generates a bypass signal for the out inhibit, which allows normal automatic rod control.

7 Reactor power demand remains limited to 55 percent maximum in automatic control until the fault is
7 corrected.

2

Sequence Monitor

Design Basis - To detect any motion of the regulating rod groups outside of the predetermined automatic sequence patterns, and to prevent further automatic motion when such conditions occur.

Circuit Operation - The sequence monitor continuously compares the group average (reference) signals for each regulating rod group with the allowable sequence patterns. Bistable amplifiers and digital logic are used for this purpose. In addition, the rod group "enable" circuits are monitored to .determine if a group is enabled for motion out-of-turn. The safety rod groups' out limit signals serve as a permissive to automatic sequencing: the sequence monitor prevents automatic control until the safety rods are fully withdrawn.

Corrective Action - When an out-of-sequence condition is detected and operation is in the automatic control mode, the automatic mode disengages and an alarm lamp alerts the operator to the malfunction. Control reverts to manual and remains in manual until the fault is corrected and the system is reset by the operator.

8 Trip Status

8 Design Basis - To sense the status of trip devices and trip channels.

8 Circuit Operation - The circuit contains elements, which sense the state of each trip device as well as the
8 state of each of the four trip channels. If a trip device or a trip channel is in a trip state, its associated
8 annunciator will alarm. The annunciators are used by operations to detect faults that may affect operation
8 of the trip circuits, such as one trip breaker in the tripped position during normal operation.

Corrective Action - Alarms are provided.

Safety Rods Not Withdrawn

Design Basis - To prevent, on plant startup, withdrawal of the regulating rods until the safety rods are fully withdrawn.

Circuit Operation - The circuit continuously monitors the group "out" limit for the four safety rod groups. When the four groups are all fully withdrawn, signals are sent to the sequencer and the sequence monitor which permit automatic control.

Corrective Action - Alarms are provided.

2 •

Rod Position Sensor Faults

All rod position sensor faults lead to false asymmetric, stuck, or dropped rod symptoms which are acted upon by the Asymmetric Rod Monitor previously described.

7.6.1.2 Integrated Control System

7.6.1.2.1 Design Basis

7 The Integrated Control System (ICS) provides the proper coordination of the reactor, feedwater control,
and turbine under all operating conditions. Proper coordination consists of producing the best load
7 response to the Core Thermal Power demand while recognizing the capabilities and limitations of the
reactor, steam-generator feedwater system, and turbine. When any single portion of the plant is at an
operating limit or control selection is on manual, the Integrated Control System design uses the limited or
manual section as a load reference.

The Integrated Control System maintains constant average reactor coolant temperature between 15 and 100 percent rated power, and constant steam pressure at all loads. Optimum unit performance is maintained by limiting steam pressure variations; by limiting the unbalance between the steam generator,
7 the turbine, and the the reactor; and by limiting the Core Thermal Power demand upon loss of capability of the steam generator feed system, the reactor, or the turbine generator. The control system provides limiting actions to assure proper relationships between the generated load, turbine valves, feedwater flow, and reactor power.

The response of the Reactor Coolant System to increasing and decreasing power transients is limited by the Integrated Control System as indicated in Table 7-6. The Turbine Bypass System permits a load drop of 40 percent or a turbine trip from 40 per cent load without safety valve operation.

7.6.1.2.2 Description

The Integrated Control System includes four independent subsystems as shown in Figure 7-14. The four
7 subsystems are: the Core Thermal Power Demand; the Integrated Master; the Feedwater Control; and
7 the Reactor Control. The system philosophy is that control of the plant is achieved through feed-forward
7 control from the Core Thermal Power Demand. The Core Thermal Power Demand produces demands for parallel control of the turbine, reactor, and Steam Generator Feedwater System through respective subsystems.

7 The Feedwater Control is capable of automatic or manual feedwater control from a startup to full power. The Integrated Master Control is capable of automatic or manual turbine valve control from minimum turbine load to full output, and of manual control below minimum turbine load. The Reactor Control is
7 designed for automatic or manual operation above 2 percent power, and for manual operation below 2
7 percent power.

7 The basic function of the Integrated Control System is matching Turbine and Reactor Power to Core
7 Thermal Power demand. The Integrated Control System does this by coordinating the steam flow to the turbine with the rate of steam generation. To accomplish this efficiently, the following basic reactor/steam-generator requirements are satisfied:

The ratios of feedwater flow and BTU input to the steam generator are balanced as required to obtain desired steam conditions.

BTU input and feedwater flow are controlled:

1. To compensate for changes in fluid and energy inventory requirements at each load.
2. To compensate for temporary deviations in feedwater temperature resulting from load change, feedwater heating system upsets or final steam pressure changes.

7.6.1.2.2.1 Unit Load Demand

7 The Core Thermal Power Demand Subsystem provides the operator with a means of establishing the
7 desired operating power load from the plant. The demand signal produced by this subsystem is called the
7 Core Thermal Power Demand (CTPD), and is the principle independent demand signal in the ICS.
7 Other subsystems receive the CTPD and establish final control element positions in order to meet this
7 demand.

7 The CTPD subsystem obtains a load demand signal, manually set by the operator, from the Load
7 Control Panel. The Load Control Panel is the primary operator interface to the ICS for Integrated Mode
7 operation. Pushbutton switches, digital meters, a digital thumb switch and status lamps are provided for
7 manipulation of Core Thermal Power Demand Set, the Demand Rate Set, turbine Load and Unload,

Maximum Runback function and status for various Load Limit and Tracking conditions. The CTPD substytem initiates load limiting and runback functions to restrict operation within prescribed limits. Figure 7-15 illustrates the functions incorporated in the subsystem.

The CTPD is restrained by a maximum load limiter, a minimum load limiter, a rate limiter and a runback limiter.

Rate limiting is designed as a function of load, so transients are limited as shown in Table 7-6.

The limiter acts to runback and/or limit the CTPD under any of the following conditions:

1. Loss of one or more reactor coolant pumps.
2. CTPD vs reactor coolant flow, variable limit.
3. Loss of one feedwater pump.
4. Asymmetric rod patterns exists in reactor.
5. The generator separates from the bus.
6. A reactor trip occurs.

The output of the limiters is a CTPD signal which is applied to the turbine control, feedwater control, and reactor control in parallel.

The controlling subsystems of the ICS (turbine control, feedwater control, and reactor control) normally operate in the automatic mode in response to a demand signal from the CTPD. The subsystems control function is kept within pre-established bounds under other than normal automatic operation by a "load tracking" feature built into the ICS. The ICS will switch to the load tracking mode if either of the following conditions exists:

One or more of the subsystems are in manual.

Errors greater than preset limits develop between the demand and the variable.

In this mode, the CTPD is made to follow the manual or limited control subsystem. Load tracking continues until the limiting condition is brought back to within the pre-established deadband or the subsystem is returned to automatic operation.

7.6.1.2.2.2 The Integrated Master

The Integrated Master has been designed to receive the Core Thermal Power Demand (CTPD) from the Core Thermal Power Demand Subsystem and utilize this signal as a demand for the feedwater, turbine and reactor control. A functional diagram of the Integrated Master Control is shown in Figure 7-16. The Integrated Master subsystem produces demand signals for the reactor control, feedwater control and turbine control (steam valves), to meet the CTPD, while providing coordination between the primary system, feedwater and turbine to maintain heat balance. The subsystem produces demands for total feedwater flow, reactor power and steam valve position to ensure that heat balance indicating parameters are kept within operating limits. The demands are modified during plant limited operation in accordance with the Control Priority. The ICS Control Priority for the four main heat balance variables is as follows:

Tave
Steam Header Pressure
Reactor Power
Cold Leg Temperature Difference (delta - Tc)

7 Three major control Hand/Automatic (H/A) stations are provided to give the operator a means of
7 manually setting the integrated master demand outputs. The reactor master control station allows the
7 operator to manually establish a demand for reactor NI-Flux and to set the controlling reactor coolant
7 system Tave set point. The steam generator master H/A station allows the operator to manually establish
7 the total feedwater flow demand. The turbine control H/A station allows the operator to establish the
7 EHC load reference motor (LRM) position and to set the controlling turbine header pressure set point.

7 **Turbine Control**

7 Control of the turbine is accomplished by a pressure controller. The turbine header pressure is compared
7 to a set point (set by the operator from the turbine H/A station) and this error drives a pulser. The
7 resulting pulses are sent to the turbine governor load reference motor (LRM) control where they are
7 integrated into a steam valve position demand. The pulser will continue to generate a demand for turbine
7 valve movement until the pressure error is reduced to zero.

7 The turbine control H/A station gives the operator the option of letting the turbine control pressure or,
7 by transferring the turbine control station to manual, allowing the operator to establish the amount of
7 electrical load generation.

7 The "LOAD" and "UNLOAD" push buttons on the "Load Control Panel" provide the operator interface
7 with the turbine load and unload system. The turbine load and unload system enables the operator to
7 smoothly introduce and remove the main turbine into/from the plant control process. The system is
7 necessary because the reactor may be operated in automatic at a power level significantly below the
7 normal minimum load of the turbine.

7 **Turbine Bypass**

7 The Turbine Bypass System operates from the turbine header pressure error or individual steam generator
7 pressures as an overpressure relief for the turbine header. The turbine bypass valves receive control inputs
7 from their respective OTSG outlet pressure , unless the main turbine is in automatic. If the main turbine
7 is in automatic, the bypass valves use the turbine header pressure error signal, which is the same signal
7 controlling the main turbine controller.

7 The turbine bypass valves serve four functions:

7 1. Provide pressure control at low loads before the turbine can be placed in automatic.

7 2. Provide a high pressure relief if the turbine header pressure exceeds its set point (normally 885 psig)
7 by 50 psig.

7 3. Provide an independent high pressure relief that operates proportionally to steam generator pressure
7 above 1035 psig.

7 4. Provide pressure control after a reactor trip at 125 psi above normal set point to prevent excessive
7 cooling of the reactor coolant fluid.

7 Once the main turbine is placed in automatic control, and loaded, the turbine bypass valves assume over
7 pressure control at set point plus 50 psi.

7 *7.6.1.2.2.3 Feedwater Control*

7 The Feedwater Control Subsystem has been designed to receive the total feedwater demand signal from
7 the Integrated Master Subsystem and utilize this signal to develop demand signals for control of the

7 feedwater pumps and the feedwater valves for each steam generator. A functional diagram of the
7 Feedwater Control Subsystem is shown in Figure 7-17.

7 The total feedwater demand signal developed in the Integrated Master Subsystem is corrected for
7 feedwater temperature in the Feedwater Control Subsystem. A proportional correction is also applied to
7 the feedwater demand when RC Pressure is greater than 2250 psig. The feedwater demand signal is limited
7 when Neutron Error exceeds +/- 5%.

7 The corrected total feedwater demand signal is modified to provide a feedwater demand signal for each
7 steam generator. Under normal conditions, each steam generator will produce one-half of the total load.
7 The steam generator load ratio control (delta Tc control) is provided to balance reactor inlet coolant
7 temperatures during operation with more reactor coolant pumps in one loop than in the other. The steam
7 generator load ratio control (delta Tc control) signal is modified by an anticipatory delta Tc error circuit
7 which is based upon a ratio of the measured RC flow.

7 A Feedwater Master Hand/Automatic control station for each steam generator enables manual control by
7 the operator or operation in automatic. In the automatic mode of operation, feedwater flow is controlled
7 by either level control or flow control. Each steam generator may independently operate on level or flow
7 control.

7 Level control ("Low Level Limits", LLL) exists when loop Tave is less than the Tave set point and the
7 steam generator level is equal to or less than the steam generator low level set point. During this mode,
7 steam generator startup level provides a demand signal to the feedwater valves for control of feedwater
7 flow to the steam generator.

7 Flow control exists when Tave is equal to or greater than the Tave set point and steam generator level is
7 greater than the low level limit.

7 During the flow control mode, the loop feedwater master demand is compared to steam generator
7 feedwater flow and to a maximum steam generator operate level set point. The resultant feedwater error
7 signal is utilized to develop the position demand signal for the feedwater valves. The feedwater error signal
7 drives the feedwater valves to make feedwater flow match loop feedwater flow demand, or to limit the
7 maximum steam generator level.

7 Feedwater flow to each steam generator is controlled by two valves, a startup valve and a main valve. The
7 startup feedwater control valve provides feedwater flow control from startup to approximately 15 percent
7 reactor power. The main feedwater control valve provides feedwater flow control from approximately 15
7 percent to 100 percent power. Each feedwater valve has a Hand/Automatic control station which enables
7 automatic control or the operator to manually establish a valve position demand.

7 Feedwater flow to both steam generators is provided from two turbine driven main feedwater pumps. The
7 speed of both feedwater pumps is controlled by a single automatic controller to maintain a constant
7 differential pressure across the feedwater valves. Feedwater valve differential pressure is compared to set
7 point and the resultant error is the controller demand signal. The loop A and loop B feedwater master
7 demand signals are input to the controller as a feed forward signal to reduce the amount of feedwater
7 valve differential pressure change during load changes. Each main feedwater pump has a Hand/Automatic
7 control station which enables automatic control or the operator to manually establish a pump speed
7 demand.

7 Feedwater Control - Reactor Coolant Pumps tripped

7 Upon loss of all reactor coolant pumps, the ICS positions valves to direct main feedwater flow to the
7 auxiliary feedwater header in each steam generator. The steam generator operate level is used as a demand
7 signal to the startup feedwater valve to establish ″natural circulation″ cooling of the reactor coolant
7 system.

7 *7.6.1.2.2.4 Reactor Control*

7 The reactor control is designed to maintain a constant average reactor coolant temperature over the load
7 range from 15 to 100 percent of rated power. The steam system operates on constant pressure at all loads.
7 The average reactor coolant temperature decreases over the range from 15 percent to zero load.
7 Figure 7-18 shows the reactor coolant and steam temperatures and the steam pressure over the entire load
7 range.

7 The Reactor Control Subsystem controls the neutron flux production of the reactor. The subsystem varies
7 the neutron flux such that primary temperature and pressure requirements are maintained, while the heat
7 drawn from the primary system meets the CTPD.

7 The reactor control subsystem controller receives inputs from core thermal power demand, reactor coolant
7 pressure and reactor coolant average temperature. The output of the controller is an error signal that
7 causes the control rod drives to be positioned until the error signal is within a deadband. A block diagram
7 of the reactor control is shown on Figure 7-19.

7 A reactor power demand can be established in two ways. The operator can manually establish a reactor
7 power demand using the reactor master hand/automatic control station. The second method of
7 establishing a reactor power demand is with the reactor master control station in automatic. In this mode
7 of operation, the reactor demand becomes a function of CTPD with a modification from Tave, steam
7 pressure and transient RC pressure control.

7 Cross limits are employed between the reactor control and feedwater control subsystems to help ensure
7 that the basic demand relationships between the reactor and feedwater are preserved during transients. In
7 addition to cross limits, the controller also incorporates a high limit on reactor power level demand.

7 The reactor power level demand is compared with the reactor power level (neutron flux). The resultant
7 error signal is the reactor power level error (neutron error) signal.

7 When the reactor power level error signal exceeds the deadband settings, the control rod drive receives a
7 command that withdraws or inserts rods depending upon the polarity of the power error signal.

7 The reactor controls incorporate automatic or manual rod control above 2 percent of rated power and
7 manual control below 2 percent of rated power.

7 **7.6.1.2.3 System Evaluation**

7 Redundant sensors for major system parameters are available to the Integrated Control System. The list of
7 redundant major system parameters is contained in Section 7.4.2.2.2, "Non-Nuclear Process
7 Instrumentation in Regulating Systems."

7 Automatic signal selection between the redundant sensors is provided as described in Section 7.4.2.2.2,
7 "Non-Nuclear Process Instrumentation in Regulating Systems." The operator can manually select
7 between the redundant sensors which are monitored by SASS; however, if a failure occurs the automatic
7 signal selector (SASS) will transfer the output signal from the failed device to the valid input. The SASS
7 also will not allow the operator to select the failed sensor if the failure occurred on the non-selected
7 sensor. The ″Control STAR″ uses the median signal selection technique to select between redundant

7 sensors. If a sensor failure occurs the "Control STAR" automatically transfers to the valid redundant
7 sensor. The operator does not have manual selection capability between the redundant sensors which
7 input to "Control STAR"; however, specific sensors can be selected by special maintenance techniques.

7 Manual reactivity control is available at all power levels. Loss of electrical power to the ICS Automatic
7 control reverts the control system to manual.

7 Maloperation or failure of any ICS subsystem places no automatic limitations on reactor operation
7 because the ICS reverts to the manual mode. Therefore other ICS subsystems follow the limited
7 subsystem.

The design of the NNI/ICS System in conjunction with procedures and training allow the operator to cope with various loss of power situations. Also, alarm indications provide information to the operator of various instrument and control functions. Emergency procedures provide assurance of positive responses by the operator.

8 Failure of the ICS does not diminish the safety of the reactor. None of the functions provided by the ICS
are required for reactor protection or for actuation of the ESPS. The reactor protection criteria, used in
8 the analysis of accidents presented in Chapter 15, "Accident Analyses" can be met irrespective of ICS
action.

7.6.1.2.3.1 Modes of Control

7 The Integrated Control System is designed to revert to a "Tracking" mode to tie the unit to the subsystem
on manual or to the subsystem being limited. In the startup control mode, the reactor is prevented from
7 automatic rod withdrawal below 1.5 percent power.

7 The controls will limit steam bypass to the condenser when condenser vacuum is inadequate.

7.6.1.2.3.2 Loss-of-Load Considerations

7 The nuclear unit is designed to accept 10 percent step load rejection without safety valve action or turbine
7 bypass valve action. The combined actions of the control system and the turbine bypass valve permit a
7 load reduction from 40 percent load without safety valve action. The controls will limit steam dump to
7 the condenser when condenser vacuum is inadequate, in which case the steam safety valves may operate.
7 The combined actions of the control system, the turbine bypass valves and the steam safety valves permit
7 separation from the external transmission system without a reactor trip for power levels less than 50
7 percent.

7 The features that permit continued operation under load rejection conditions include:

7 Integrated Control System

7 During normal operations, the Integrated Control System controls the unit load in response to the core
7 thermal power demand (CTPD) set by the operator. During loss of load, the CTPD is limited to a
7 maximum 20 percent. The ICS will control reactor power, feedwater flow and bypass valve position to
7 maintain the CTPD, Tave and steam pressure. The turbine governor takes control to regulate frequency.

7 100 Percent Relief Capacity in the Steam System

7 This provision acts to reduce the effect of large load drops on the Reactor System.

7 Consider, for example, a sudden load rejection from a power level above 20 percent. When the
7 turbine-generator starts accelerating, the governor valves and the intercept valves close to maintain set
7 frequency. As the governor valves close, steam pressure rises, forcing reduced energy transfer from the
7 primary system and causing reactor coolant average temperature to rise. At the same time, a power
7 demand runback is initiated to 20 percent power by the CTPD, causing reduction in the feedwater and
7 reactor demand signals. The rise in reactor coolant temperature will help initially reduce reactor power
7 along with the reduction in demand. The bypass valves will open in response to the increased steam
7 pressure to reject the excess steam flow to the condenser. In addition, when the load rejection is of
7 sufficient magnitude, the safety valves open to exhaust steam to the atmosphere. If transient conditions
7 warrant, the feedwater system will increase feedwater flow to mitigate the undercooling condition caused
7 by the sudden reduction in steam flow from the loss of load.

7 As operation continues with the turbine- generator carrying the in-house electrical loads, the turbine
7 control will operate in the frequency control mode, the reactor and feedwater will operate to maintain
7 proper reactor conditions at reduced demand and the bypass system will reject the excess steam flow to
7 the condenser to control steam pressure.

7.6.1.2.3.3 Loss of Power Supply Considerations

The ICS/NNI system power supply is arranged such that it is normally powered from a dedicated static inverter system, which receives a DC input from the Vital I & C batteries, and is backed by an AC input from one of the plants regulated non-load shed buses (Chapter 8, "Electric Power"). Both automatic and manual transfer switching is provided to select between these supplies.

In addition to the power supply reliability for the ICS, essential plant parameters necessary for shutdown have been arranged with their power supplies independent of the ICS source. Also, a "display group" has been developed and defined on the plant operator aid computer such that upon a loss of ICS power, the operator may quickly have full and complete information on key primary and secondary system parameters. Emergency procedures have also been developed to designate alternate sources of information on key plant parameters if the computer is unavailable, thus assuring the operator can obtain sufficient systems information.

If a loss of power event occurs, the ICS/NNI is designed to send the plant to a "Known Safe State"
(KSS) by initiating a trip of both main feedwater pumps via the failsafe design of the high steam generator
7 level monitoring circuits. These circuits are designed such that upon a loss of both "hand" and "auto"
7 power they will initiate a trip of the main feedwater pumps and main turbine which will also trip the
reactor via the Anticipatory Reactor Trip System (ARTS) circuitry. Emergency feedwater is also initiated
7 upon loss of both feedwater pumps as described in Section 7.4.3, "Emergency Feedwater Controls." Upon
7 loss of either "hand" or "Auto" power, steady state operation is maintained.

7.6.2 INCORE MONITORING SYSTEM

The Incore Monitoring System has been upgraded to meet the requirements of NUREG 0737 Item II.F.2.

7.6.2.1 Description

The Incore Monitoring System provides neutron flux detectors to monitor core performance. Incore self-powered neutron detectors measure the neutron flux in the core to provide a history of power distributions during power operation. Data obtained provides power distribution information and fuel burnup data to assist in fuel management decisions. The plant computer provides normal system readout and a backup readout system is provided for selected detectors.

7.6.2.2 System Design

The Incore Monitoring System consists of assemblies of self-powered neutron detectors and temperature
8 detectors located at preselected positions within the core. Each core can contain up to 52 incore
8 assemblies. The incore monitoring locations are shown on Figure 7-20. In this arrangement, an incore
8 detector assembly consisting of seven local flux detectors, one background detector, one thermocouple and
8 a calibration tube is installed in an instrumentation guide tube. The local detectors are positioned at
seven different axial elevations to indicate the axial flux gradient. The outputs of the local flux detectors are referenced to the background detector output so that the differential signal is a true measure of neutron flux. The temperature detectors located just above the top of the active fuel in the fuel assemblies measure core outlet temperature.

Multi-point recorder readouts of selected detectors are provided independent of the computer.

When the reactor is depressurized, the incore detector assemblies can be inserted or withdrawn through guide tubes which originate at a shielded area in the Reactor Building as shown in Figure 7-21. These guide tubes enter the bottom head of the reactor vessel where internal guides extend up to the instrumentation tubes of 52 selected fuel assemblies. The instrumentation tube serves as the guide for the incore detector assembly. During refueling operations, the incore detector assemblies are withdrawn approximately 13 feet to allow free transfer of the fuel assemblies. After the fuel assemblies are placed in their new location, the incore detector assemblies are returned to their fully inserted positions.

7.6.2.3 Calibration Techniques

The nature of the detectors permits the manufacture of nearly identical detectors which produces a high relative accuracy between individual detectors. The detector signals are compensated continuously for burnup of the neutron-sensitive material.

Calibration of detectors is not required. The incore self-powered detectors are controlled to precise levels of initial sensitivity by quality control during the manufacturing stage. The sensitivity of the detector changes over its lifetime due to such factors as detector burnup, control rod position, fuel burnup, etc. The results of experimental programs to determine the magnitude of these factors have been incorporated into calculations and are used to correct the output of the incore detectors for these factors. Operation of these detectors in both power and test reactors has demonstrated that this compensation program, when coupled with the initial sensitivity, provides detector readout accuracies sufficient to eliminate the need for a calibration system.

7

7.6.2.4 System Evaluation

7.6.2.4.1 Operational Experience

Self-powered incore neutron detectors have been operated since 1962. Such detectors have been assembled and irradiated in a Babcock & Wilcox development program that began in 1964.

The B&W Development Program included these tests:

1. Parametric studies of the self-powered detector.
2. Detector ability to withstand PWR environment.
3. Multiple detector assembly irradiation tests.
4. Background effects.
5. Readout system tests.
6. Mechanical withdrawal-insertion tests.
7. Mechanical high pressure seal tests.
8. Relationship of flux measurement to power distribution experiments.

Conclusions drawn from the results of the test programs are as follows:

1. The detector sensitivity, resistivity, and temperature effects are satisfactory for use.
2. A multiple detector assembly can provide axial flux data in a single channel and can withstand reactor environment.
3. Background effects will not prevent satisfactory operation in a PWR environment.
4. Plant computer systems are successful as read-out system for in-core monitors.

For Incore Monitoring System development program results and conclusions, refer to B&W Topical Report BAW-10001A; "Incore Instrumentation Test Program."

7 **7.6.2.4.2 Deleted Per 1997 Update**

7

7.6.2.5 Detection and Control of Xenon Oscillations

Under normal operating conditions, the incore detectors supply information to the operator in the control room.

Each individual detector measures the neutron flux at its locality and is used to determine the local power density. The individual power densities are then averaged and a peak-to-average power ratio calculated. This information can be used to indicate possible power oscillations.

7.7 OPERATING CONTROL STATIONS

Following proven power station design philosophy, all control station, switches, controllers, and indicators necessary to start up, operate, and shut down Oconee 1 and 2 are located in one control room. Controls for Oconee 3 are located in a separate control room. Control functions necessary to maintain safe conditions after a loss-of-coolant accident are initiated from the centrally located control rooms. Controls for certain auxiliary systems are located at remote control stations when the system controlled does not involve unit control or emergency functions.

7.7.1 GENERAL LAYOUT

The control room for Oconee 1 and 2 is designed so that one man can supervise operation of both units during normal steady state conditions. During other than normal operating conditions, other operators are available to assist the control operator. Figure 7-26 shows the control room layout for Oconee 1 and 2. Oconee 3 has similar accessibility to the various controls. The control boards are subdivided to show the location of control stations and to display information pertaining to various sub-systems.

7.7.2 INFORMATION DISPLAY AND CONTROL FUNCTIONS

Consideration is given in the control board layout to the fact that certain systems normally require more attention from the operator. The Integrated Control System is therefore located nearest the center line of the boards (Section 1 on Figure 7-26).

On Section 2 of the control board, one indicator will be provided for each control rod. Fault detectors in the Rod Drive Control System are used to alert the operator should an abnormal condition exist for any individual control rod. Displayed in this same area are limit lights for each control rod group and all nuclear instrumentation information required to start up and operate the reactor. Control rods are manipulated from the Section 2 bench position. Plant computer readout facilities for alarm monitoring and sequence monitoring are located here to aid the operator.

A plant computer is used on each unit to provide fuel management measurements and calculations.
7 These computers also provide for alarm monitoring, performance monitoring, data logging, and sequence
7 monitoring during start-up and shut-down of the turbine-generator. Monitoring and display functions of the plant computer which audit Nuclear Steam Supply System parameters of major interest are duplicated elsewhere in the control rooms. This type of computer application has been successfully applied to units presently in operation on the Duke system.

Variables associated with operation of the secondary side of the station are displayed and controlled from Section 1 and 3 of the control board. These variables include steam pressure and temperature, feedwater flow and temperature, electrical load, and other signals involved in the Integrated Control System. Section 3 of the control board also contains indication and controls of the Reactor Coolant System parameters.

The Engineered Safeguards System is controlled and monitored from Section 8 of the vertical boards. Indicating lights are provided as a means of verifying the proper operation of the Engineered Safeguards System. Control switches located on this panel allow manual operation of equipment that is not controlled elsewhere in the control room or test of individual units.

Control and display equipment for station auxiliary systems are located on Section 6 of the control board.

Reactor coolant pump controls located on Section 5 of the control boards consists of the pump controls and auxiliary instrumentation required for pump operation. Also mounted on this section are the Auxiliary Electrical System controls required for manual switching between the various power sources described in Section 8.2, "Offsite Power System" and Section 8.3, "Onsite Power Systems."

Controls and indications for all normal ventilation systems are located on Section 7 of the control boards.

In order to maintain the desired accessibility for control of the station, miscellaneous recorders not required for station control are located on the vertical recorder boards where they are visible to the operator. Radiation monitoring information is also indicated there.

9 Radiation monitoring display and transient monitoring system are combined in the process monitoring
9 computer (PMC). The radiation monitoring display provides supervisory control and display of
9 information from field mounted radiation monitoring equipment. The transient monitoring system
9 automatically records pre-selected plant parameters (temperatures, pressures, flowrates, etc.) for analysis
9 and diagnoses of plant transients or reactor trip. Like the OAC, most of the information provided by the
9 PMC is either duplicated elsewhere in the control room, or deemed not significant enough to have a
9 dedicated display device. The PMC is not QA-1, redundant, or single failure proof. The PMC is
9 independent of the OAC. The PMC is not relied upon to initiate a reactor trip, mitigate an accident, or
9 actuate a safety system, and performs only supervisory control to field mounted radiation monitoring and
9 sampling equipment.

7.7.3 SUMMARY OF ALARMS

Visible and audible alarm units are incorporated into the control boards to warn the operator if limiting conditions are approached by any system. Audible Reactor Building evacuation alarms are initiated from the Radiation Monitoring System and from the source range nuclear instrumentation. Audible alarms are sounded in appropriate areas throughout the station if high radiation conditions are present in that area. Alarms for the nuclear systems are indicated in process diagrams in Chapter 6, "Engineered Safeguards,"
7 Chapter 7, "Instrumentation and Control," and Chapter 9, "Auxiliary Systems." Alarms are provided to
7 warn security of unauthorized entry into vital areas.

7.7.4 COMMUNICATIONS

7.7.4.1 Control Room to Inside Station

6 The telephones for the site are connected to a Private Automatic Branch Exchange (PABX) located inside
6 the Oconee Office Building. The PABX has capability of up to 10,000 lines and provides access for communications and paging. The equipment provides 4-digit dialing, dial tone, ring-back tone and busy tone. The PABX is powered by 48VDC batteries, which are charged through an inverter/charger combination, fed by a 480VAC supply. Upon loss of normal AC power, the system batteries will provide required power for a minimum of four (4) hours. Alternate power is automatically provided from the emergency diesel generator provided for the building.

6 The public address system is accessible through plant telephones by dialing a access code. In the event of PABX failure, the PA system is operable through eleven handsets installed at strategic locations within the station.

8 A radio transmitter/receiver communication system is provided between the control room and the rest of
8 the station. This system is used during normal plant operation and during outage, security or fire
8 situations. Radio transmission is only available in a reactor building when an antenna is activated by the

8 unit 1 & 2 control room. Usage of the radio communication system in the reactor building is limited to
8 times when the unit is open for access.

8 A sound powered telephone system was supplied during original plant design, but radio utilization allows
8 this system to be an available but nonessential system. This system consists of a network of conductor
8 pairs converted to jacks throughout the plant. Sound powered handsets are plugged into the jacks to
8 form talking paths with separate talking paths available for each unit. The system is completely
8 independent from any other telephone system and involves no external power supply.

7.7.4.2 Control Room to Outside Station

8 The commercial telephone network and the Duke Power fiber optic network provide communication to
8 outside the station area. An interface is provided between the PABX and the commercial telephone lines
8 and another interface is provided between the PABX and the Duke Power fiber optic network which
6 includes access to the General Office at Charlotte, Transmission Control Center, System Operating
8 Center, and Lee Steam Station. Ringdown phone service (independent of the PABX) is also provided
8 through the fiber optic network to the Transmission Control Center, System Operating Center, and Lee
7 Steam Station.

8 The control room is also equipped with a transmitter-receiver which operates at 800 megahertz to provide
8 communication between the control room and the System Operating Center, Transmission Control
8 Center, and Bad Creek, Jocassee, and Keowee Hydro Stations.

8 7.7.4.3 Deleted per 1998 Revision

8

7.7.5 OCCUPANCY

Safe occupancy of the control room during abnormal conditions is provided for in the design of the Auxiliary Building. Adequate shielding is used to maintain tolerable radiation levels in the control rooms for maximum hypothetical accident conditions. Each Control Room Ventilation System is provided with radiation detectors and appropriate alarms. See Section 9.4.1, "Control Room Ventilation" for control room ventilation systems description. Emergency lighting is provided.

The potential magnitude of a fire in either control room is limited by the following factors:

1. The control room construction and furnishings are of noncombustible materials.

9 2. Control cables and switchboard wiring meet the flame test as described in IEEE 383-1974. (Reference
9 IPCEA S-19-81 & ASTMD 2220-68)

3. Qualified trained personnel, adequate extinguishers, and accessibility to all control room areas are provided.

A fire, if started, would be of such a small magnitude that it could be extinguished by the operator using a hand fire extinguisher. The resulting smoke and vapors would be removed by the ventilation system.

Essential auxiliary equipment is controlled by either stored energy, closing-type, air circuit breakers which are accessible and can be manually closed in the event DC control power is lost, or by AC motor starters which have individual control transformers.

2 7.7.5.1 Emergency (Auxiliary) Shutdown Panel

If temporary evacuation of the control room is required while operating at any power, the operator will
6 trip the control rods and start the Keowee hydro units prior to evacuating the control room. This action
6 can also be accomplished from the cable room located one elevation below the control room. After
evacuation, the operator can establish and maintain a hot shutdown condition from the emergency shutdown panel located outside the control room. The following instrumentation and controls are available on the emergency shutdown panel:

1. Pressurizer Level Indicator
2. Pressurizer Heater Control
3. RC Pressure Indicator
4. RC Outlet Temperature Indicator
5. Turbine Steam Supply Header Pressure Indicator
6. Turbine Bypass Valve Loop "A" Station
7. Turbine Bypass Valve Loop "B" Station
8. Startup Feedwater Valve Loop "A" Station
9. Startup Feedwater Valve Loop "B" Station
10. Steam Generator "A" Startup Level
11. Steam Generator "B" Startup Level
12. Letdown Storage Tank Level Indicator
13. HP Injection Pump "B" Control Switch

5 14. Pressurizer Level Control Station

If HP Injection Pump "A" is in operation, it can be tripped from the 4.16 KV switchgear located on elevation 796′ + 6″. The operator has control of HP Injection Pump "B" at the emergency shutdown panel. Makeup to the letdown storage tank can be obtained, if desired, from one of the following sources:

1. RC Bleed Holdup Tank
2. Concentrated Boric Acid Storage Tank
3. Boric Acid Mix Tank

The necessary pumps can be controlled from the waste disposal control panel.

2 7.7.5.2 Standby Shutdown Facility

2 The Standby Shutdown Facility (SSF) provides a secondary alternate and independent means to achieve
2 and maintain a hot shutdown condition for scenarios in which the Control Room is unavailable or
2 equipment it controls is unavailable. The SSF was designed for safe shutdown during postulated fire,
2 Turbine Building flooding, and physical security events. The following instrumentation and controls are
2 available on the SSF:

2 <u>SSF DIESEL GENERATOR AND STATION RELATED CONTROLS AND</u>
2 <u>INSTRUMENTATION</u>

2 1. Diesel Generator Annunciator Panel

8 2. Diesel Generator Controls
8 3. Diesel Generator Metering
8 4. Diesel Generator Syncroscope
8 5. SSF Power Systems Breaker Controls and Indicating Lights
8 6. SSF Power Systems Metering
8 7. SSF Diesel Engine Service Water Pump Control
8 8. SSF Diesel Engine Service Water Pump Discharge Flow Meter
8 9. SSF Auxiliary Service Water Pump Control
8 10. SSF Auxiliary Service Water Pump Discharge Flow Meter
8 11. SSF Sump Pump Controls

2 SSF UNIT RELATED CONTROLS AND INSTRUMENTATION

2 1. Unit Annunciator
2 2. Unit Recorder
2 3. SSF RC Makeup System
2 a. Pump Controls
2 b. Valve Controls
2 c. Pump Suction Pressure and Temperature Indication
6 d. Pump Discharge Pressure and Flow Indication
2 4. Unit Process Indicators
2 a. Pressurizer Level
2 b. Pressurizer Pressure
2 c. RC Loop A and B Hot Leg Temperatures
2 d. RC Loop A and B Cold Leg Temperatures
2 e. RC Loop A and B Pressure
2 f. Steam Generator Level A and B
2 g. Steam Generator Auxiliary Service Water Flow
2 5. Unit Controls
2 a. Letdown Cooler A and B Outlet Valve
2 b. Pressurizer Water and Steam Space Samples
2 c. Steam Generator A and B Feedwater Control Valve
2 d. Boron Dilution Block Valve
2 e. Pressurizer Relief Block Valve
2 f. Pressurizer Heaters
2 g. Steam Generator A and B Emergency Feedwater Valves
2 6. Power Systems Alignment Indicating Lights

7.7.6 AUXILIARY CONTROL STATIONS

Auxiliary control stations are provided where their use simplifies control of auxiliary systems equipment
6 such as waste evaporator, sample valve selectors, chemical addition, etc. The control functions initiated
6 from local control stations do not directly involve either the Engineered Safeguards System if actuated or
6 the Reactor Control System. Sufficient indicators and alarms are provided so that the Oconee control
room operator is made aware of abnormal conditions involving remote control stations.

7.7.7 SAFETY FEATURES

Control room layouts provide the necessary controls to start, operate and shut down the units with sufficient information display and alarm monitoring to assure safe and reliable operation under normal and accident conditions. Special emphasis is given to maintaining control during accident conditions.

The layout of the engineered safeguards section of the control board is designed to minimize the time required for the operator to evaluate the system performance under accident conditions.

1 7.8 ANTICIPATED TRANSIENTS WITHOUT SCRAM (ATWS)
1 MITIGATION SYSTEM

1 7.8.1 DESIGN BASIS

5 The ATWS system that is installed at the Oconee Nuclear Station is based upon the B&WOG Generic
1 ATWS Design Basis Document 47-1159091-00 dated October 9, 1985, subsequent B&WOG ATWS
1 Committee submittal dated December 1, 1987, the Safety Evaluation Report on B&WOG 47-1159091-00
1 contained in the NRC letter to DPCo dated July 26, 1988, and the September 7, 1988 letter G. Holohan
1 (NRC) to L. Stalter (B&WOG).

1 7.8.2 SYSTEMS DESIGN

1 The ATWS Mitigation System is composed of two parts, the ATWS Mitigating Systems Actuation
1 Circuitry (AMSAC) and the Diverse SCRAM System (DSS).

1 The ATWS Mitigation System Actuation Circuitry (AMSAC) and Diverse Scram System (DSS) consist
1 of two Programmable Logic Controllers (PLC's) for the logic control circuits and two Uninterruptible
1 Power Sources (UPS) connected to offsite power. Inputs from the field sensors are wired to the PLC's
1 and outputs to the final actuation devices are wired using interfacing relays housed with the ATWS
1 equipment cabinets and powered from the UPS. The UPS's are powered from a 120 VAC local
1 panelboard backed by the Oconee Station emergency source (Keowee Hydroelectric Generating Station).
1 The 2 UPS's are isolated from the emergency source by individual fuses coordinated with the panelboard
1 circuit breakers and the upstream distribution network.

1 The AMSAC/DSS System consists of a two channel energize-to-trip design with the AMSAC portion
1 actuated on low Feedwater Pump Turbine (FDWPT) control oil pressure or low Feedwater Pump
1 (FDWP) discharge pressure while the DSS portion is actuated upon high Reactor Coolant System (RCS)
1 Pressure.

1 All AMSAC/DSS PLC's and UPS power supplies are located in a stand-alone cabinet located above the
1 Control Room in what is called the Ventilation Room. This location is convenient to the Control Room
1 and allows easy access for testing and maintenance. This location is a Mild Environment.

1 All AMSAC/DSS process monitoring inputs are provided by existing Oconee instrumentation and control
1 systems. RCS pressure inputs to the DSS which are analog signals are currently displayed on the Main
1 Control Boards. Annunciator alarms are provided in the Control Room to alert the operator that one
1 channel for either AMSAC or DSS has actuated.

1 7.8.2.1 AMSAC

1 Each channel of AMSAC uses existing inputs from the Feedwater System which monitor FDWPTA(B)
1 hydraulic control oil pressure and FDWPA(B) discharge pressure signals (one per pump to each channel)
1 from pressure switches which are part of the original Oconee feedwater system design.

1 These signals are multiplied using relays to provide the contact inputs which will be wired directly to the
1 PLC's. These signals are processed using programmable logic resident in the PLC to provide the outputs
1 to the Main Turbine and the Emergency Feedwater System.

1 AMSAC interfaces with the following systems and devices:

	FROM	TO	ISOLATION
1 1	AMSAC PLC Interfacing Relays	Main Turbine Trip Solenoid	NE to NE
9			
1 1	AMSAC PLC Interfacing Relays	EFDW Pump Start Circuits	NE to 1E
1	AMSAC Channels Actuation	Control Room Annunciator	NE to NE
1	NE = Non-Class 1E	1E = Class 1E	

1 Feedwater Pump Turbine Oil Pressure is sensed by pressure switches in the Feedwater Pump Turbine
1 Control Console on the turbine standard. These switches are then multiplied using control relays for
1 output to various plant control, monitoring and alarm circuits. AMSAC will be one of the end users of
1 these signals.

1 Feedwater Pump Discharge Pressure is sensed by pressure switches in the discharge lines of each
1 individual pump. These switches are then multiplied using control relays for output to various plant
1 control, monitoring and alarm circuits. AMSAC will be one of the end users of these signals.

1 7.8.2.2 DSS

1 Each channel of DSS uses a Wide Range RCS Pressure signal supplied via an analog isolator from the
1 Westinghouse supplied Reactor Vessel Level Indication System (RVLIS). These signal loops also provide
1 the Regulatory Guide 1.97 wide range RCS pressure indications on the main control board. The DSS
1 will utilize the signal conditioning equipment which is resident in the RVLIS cabinet through an isolation
1 device that separates the Class 1E RVLIS from the Non-Class 1E DSS. DSS trip actuation is initiated at
1 a setpoint of 2450 ± 25 psig using the logic in the PLC. Outputs from both channels of the PLC's are
1 combined to make the required two-out-of-two logic. Upon actuation of both channels of DSS, relays
1 will energize and interrupt the power to the Control Rod Drive System (CRDS) programmers in Control
9 Rod Groups 5, 6 and 7 as well as the auxiliary programmer control assembly and will raise the Turbine
9 Bypass Valve Setpoint to ensure shutdown margin requirements.

1 DSS interfaces with the following systems and devices:

	FROM	TO	ISOLATION
1	DSS Interfacing Relays	CRD Groups 5, 6, 7	NE to NE
9	DSS Interfacing Relays	TBV's Control Setpoint	NE to NE
1	DSS Interfacing Relays	Auxiliary Rod Controls	NE to NE
1	DSS Channel Actuation	Control Room Annunciator	NE to NE
1	WR RCS Pressure (RVLIS)	DSS PLC Channels	1E to NE
1	NE = Non-Class 1E	1E = Class 1E	

1 For each unit the Control Rod Drive System (CRDS) will also provide an input from the CRDS
1 Diamond panel located in the main Control Room into the DSS logic for reset of the CRDS Solid State
1 Programmers.

7.8.2.3 Testing

Inputs are also provided from the ATWS test panel. The panel is resident in the PLC cabinet along with other ATWS equipment.

Periodic testing will use a Bypass/Enable switch located on the test panel for testing each channel of AMSAC and DSS logic in the PLC. Whenever this switch is not in the ENABLE position, a continuous indicator in the Control Room will be illuminated and a computer alarm will be generated for display in the Control Room on a CRT. Status indication of all inputs and outputs are on the test panel.

These systems are designed so that both are two out of two logic actuated systems, and provisions are incorporated which allow disabling of the system output when one of the channels is placed in test. This prevents accidental initiation of the systems during individual channel testing.

7.8.2.4 AMSAC and DSS I/O

Each input to the AMSAC and DSS logic is provided with complete indications and alarms that alert the operator to an off-normal status that might preclude an ATWS event. Each plant variable that inputs into the AMSAC and DSS is monitored as part of the existing plant indications and provide the operator with information relevant to the status of each variable prior to reaching the AMSAC or DSS set point.

Outputs from the PLC's are provided through interfacing relays located in the ATWS equipment cabinets. These relays provide the outputs to the Main Turbine, Turbine Bypass Valve Set Point, the Emergency Feedwater Pumps, and the Control Rod Drive System for Groups 5, 6, 7 and the Auxiliary programmer control assembly. The relays used are powered by the UPS. Each PLC channel output relays will be wired to the above devices in a manner such that both channels of AMSAC/DSS are required for the devices to trip, start, or drop. The relays also provide output status information to the operator.

9 7.9 MAIN STEAM LINE BREAK(MSLB) DETECTION AND 9 FEEDWATER ISOLATION CIRCUITRY

9 7.9.1 DESIGN BASIS

9 The MSLB Detection and Feedwater Isolation circuitry is designed to address containment
9 over-pressurization concerns by isolating feedwater to both steam generators during a Main Steam Line
9 Break event. The MSLB Detection and Feedwater Isolation circuitry is an enhancement modification
9 (NSM-1/2/32873) in response to IE Bulletin 80-04.

9 7.9.2 SYSTEM DESIGN

9 The MSLB circuitry is comprised of two parts, the MSLB detection analog channels and the feedwater
9 isolation digital trains.

9 The MSLB detection analog channels consists of three main steam pressure channels per header. The
9 Inadequate Core Cooling Monitoring System supplies four of the six MS pressure signals that are
9 electrically isolated from the MSLB channels. Two additional QA1 MS pressure signals are installed
9 specifically for MSLB detection. Low main steam header pressure is used to indicate a main steam line
9 break. Power for the analog detection channels is supplied by 120VAC Vital power panelboards. The Unit
9 2 MSLB detection analog channels are provided with on-line test circuits to functionally verify operation
9 of the MSLB detection circuitry (NSM-23058). Signal isolation is provided between safety systems and
9 non-safety related systems.

9 There are two redundant trains of MSLB feedwater isolation circuitry. Each train is arranged in two out
9 of three logic for each main steam header. The outputs of the two out of three logic are designed to trip
9 the FDW pumps, to inhibit/stop the turbine driven EFW pump, and to isolate Main FDW and Startup
9 FDW. The circuits are an energize-to-trip design with a time delay to reduce the likelihood of spurious
9 actuation. Power for the relay logic trains is supplied by 125Vdc Vital power panelboards. Separate
9 control switches are provided for each train in the control rooms to enable/disable and to manually
9 initiate the actuation circuitry. During on-line testing of the MSLB detection analog channels, the channel
9 inputs to the MSLB feedwater isolation trains are manually disabled. An annunciator alarm is provided in
9 each control room to alert the operator of actuation of either MSLB train. Alarms for enable/disable and
9 for actuation status are available in each control room via the Operator Aid Computer.

THIS IS THE LAST PAGE OF THE CHAPTER 7 TEXT PORTION

Table 7-5. NNI Inputs to Engineered Safeguards

Characteristics	Reactor Outlet Pressure (WR)(1)	Reactor Building Pressure (WR)	Reactor Building Pressure (NR)
Component Item Number	RC3A-PT3 RC3A-PT4 RC3B-PT3	BS4-PS1 & 2 BS4-PS3 & 4 BS4-PS5 & 6	BS4-PT1 BS4-PT2 BS4-PT3
ESPS Channel	A,B,C	A,B,C	A,B,C
9 Sensor Type	Pressure	ASCO Pressure Switch	ITT Barton Pressure
Type Readout	all indicating	NA	all indicating
Power Required	external	none	external
Sensors Connected to Common Taps	See Note (3)	BS4-PS2 & BS4-PT1 BS4-PS4 & BS4-PT2 BS4-PS6 & BS4-PT3	All separate building penetrations

<u>NNI Inputs to RPS</u>

7 Characteristics	Reactor Outlet Pressure (NR)(1)	Reactor Outlet Temperature (NR)	Reactor Coolant Flow	Reactor Building Pressure (NR)
Component Item Number	RC3A-PT1 RC3A-PT2 RC3B-PT1 RC3B-PT2	RC4A-TE1 RC4A-TE4 RC4B-TE1 RC4B-TE4	RC14A-dPT1 RC14A-dPT2 RC14A-dPT3 RC14A-dPT4 RC14B-dPT1 RC14B-dPT2 RC14B-dPT3 RC14B-dPT4	BS4-PS7 BS4-PS8 BS4-PS9 BS4-PS10
Reactor Protective Channel	A,B,C,D	A,B,C,D	A,B,C,D(2)	A,B,C,D
8 Sensor Type	Rosemount Press. Transmitter	(4) RTD	Rosemount Differential Pressure	ASCO Pressure Switch
Type Readout	all indicating	all indicating	all indicating	NA
Power Required	external	external	external	none
Sensors Connected to Common Taps	(3)RC3A-PT1 & RC3A-PT3 RC3A-PT2 & RC3A-PT4 RC3B-PT1 & RC3B-PT3	All sensors have separate taps.	All sensors for same loop are connected to common taps.	All sensors have separate taps.

Note:

(1) NR = Narrow Range, WR = Wide Range

(2) Each channel has an input from each loop.

(3) Pressure taps for each RPS channel are independent. A RPS channel and an ESPS channel may have common pressure sensing taps.

8 (4) Weed Instrument RTDs installed on Unit 3 and Unit 1. Rosemount RTDs installed on Unit 2.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 8. ELECTRIC POWER

8.1 INTRODUCTION

An offsite power system and an onsite power system are provided for each unit at the Oconee Nuclear Station to supply the unit auxiliaries during normal operation and the Reactor Protection System and Engineered Safeguards Protection Systems during abnormal and accident conditions.

Each Oconee unit has six available sources of power to the Engineered Safeguards Systems as shown in Figure 8-1. These are:

1. The 230 kV transmission system and/or the 525 kV transmission system
2. Two Keowee hydro units
3. The 100 kV transmission system
4. The two other nuclear units

The normal arrangement is for three of these to serve any or all units and to be switched in the preferential order as follows: (1) the 230 kV transmission network through the unit startup transformers, (2) one Keowee hydro unit through an overhead 230 kV circuit, and (3) the other Keowee hydro unit through an underground circuit.

Whenever the underground circuit from Keowee is unavailable, a circuit from the 100 kV transmission network can be connected to the Standby Buses and serve as an emergency power source.

Any unit can provide power to another unit's Auxiliary System via the switchyard.

8.1.1 UTILITY GRID SYSTEM AND INTERCONNECTIONS

Duke Power Company is an investor-owned utility serving the Piedmont region of North Carolina and South Carolina. The Duke transmission system consists of interconnected hydro plants, fossil-fueled plants, combustion turbine units, and nuclear plants supplying energy to the service area at various voltages up to 525 kV. Duke is a member of the Virginia-Carolina (VACAR) Subregion of the Southeastern Electric Reliability Council (SERC). All the companies in the region are interconnected such that the combined networks operate as a single, integrated system.

A detailed description of the offsite power system is provided in Section 8.2, "Offsite Power System."

8.1.2 ONSITE POWER SYSTEMS

The onsite power system for each unit consists of the main generator, the unit auxiliary transformer, the
9 startup transformer, the Keowee Hydro Station, the Standby Shutdown Facility (SSF), the batteries, and the auxiliary power system. Under normal operating conditions, the main generator supplies power through isolated phase bus to the unit step-up and unit auxiliary transformers. The unit auxiliary transformers are connected to the bus between the generator disconnect link and the associated unit step-up transformer. During normal operation, station auxiliary power is supplied from the main generator through these unit auxiliary transformers. During startup, during shutdown, and after shutdown station auxiliary power is supplied from the 230 kV system through the startup transformer.

The onsite power systems and their interconnection with the offsite power system are shown in Figure 8-1.

The onsite power systems are described in detail in Section 8.3, "Onsite Power Systems."

8.1.3 SAFETY-RELATED LOADS

The loads that require electric power to perform their safety function are identified in Table 8-1.

8.1.4 DESIGN BASES

The design of the electrical systems for this three unit nuclear station is based on providing the required electrical equipment and power sources to assure continuous operation of the essential station equipment under all applicable conditions.

1 A safety related valve with electric motor actuation will be assigned a safety related power source if the
1 valve is required to respond immediately in an accident scenario in order to assure safe shutdown of the
1 plant or to mitigate the consequences of the accident. Valves (with electric motor actuators) which are
1 not required to respond immediately for accident mitigation or safe shutdown may be powered from
1 safety related sources when readily available, or from non-safety related, non-loadshed sources when the
1 following conditions exist: a) the valve actuator is equipped with manual override to allow manual
1 actuation, b) the environment in the immediate vicinity of the valve will allow operator access, c)
1 adequate time exists for operator intervention to be effective, and d) operator training is such that there is
1 reasonable expectation that operator intervention will occur when required.

8.2 OFFSITE POWER SYSTEM

2

8.2.1 SYSTEM DESCRIPTION

8.2.1.1 Utility Grid System

The primary transmission system of Duke consists of a highly integrated 525 kV and 230 kV loop network. Underlying the primary transmission system is an extensive 100 kV sub-transmission network integrated into the primary system by means of 230/100 kV tie stations.

8.2.1.2 525 kV Switching Station

Unit 3 generates electric power at 19 kV which is fed through an isolated phase bus to a unit step-up transformer where it is stepped-up to the transmission voltage of 525 kV. From the step-up transformer an overhead transmission line feeds power to the 525 kV switching station through two circuit breakers connecting the unit to the 525 kV transmission network.

Three transmission lines connect to the Oconee 525 kV Switching Station; one circuit goes east-northeast
2 to Jocassee, one east to the Newport Station and one southeast to the Georgia Power Co. In addition, a
230/525kV autotransformer connects the 525 kV switching station to the 230kV switching station. The 525 kV buses, disconnect switches, and circuit breakers are arranged into a breaker-and-a-half configuration.

8.2.1.3 230 kV Switching Station

9 Unit 1 and Unit 2 also generate electric power at 19 kV which is fed through an isolated phase bus on
each unit to its own step-up transformer, where it is stepped-up to the transmission voltage of 230 kV. From each step-up transformer, an overhead transmission line feeds power to the 230 kV switching station through two circuit breakers connecting each unit to the 230 kV transmission network. Eight transmission lines connect to the Oconee 230 kV Switching Station; two circuits are installed east-northeast to North Greenville, four east-southeast to Central, and two north-northwest to Jocassee. See Figure 8-1 and Figure 8-2 for arrangement of lines in the Oconee Station and on the site.

The 230 kV buses, disconnect switches, and circuit breakers are arranged into a breaker-and-a-half configuration.

Each unit is provided with two physically independent circuits from the switching station. One is the circuit from the 230 kV switching station through the startup transformer which is designed to be available within a few seconds following a loss of coolant accident. The second circuit is the path from the switchyard through the main step-up transformer, the main generator bus and the unit's auxiliary
8 transformer with the generator disconnected from the main bus. This second circuit was originally
8 required to be available following a hypothetical loss of all station power and the resulting LOCA in time
8 to prevent fuel and reactor coolant pressure boundary degradation. This ceased to be a requirement
8 following the 1993 UFSAR update in which the safety analysis of the hypothetical loss of all station
8 power was replaced with a station blackout analysis for Oconee. The station blackout analysis outlines the
8 use of the Standby Shutdown Facility to mitigate a station blackout while preventing a loss of coolant
8 accident. The second circuit is currently used during refueling as an additional power feed for the

8 shutdown unit(s) from the 230kv switchyard. Both the unit auxiliary transformer and the startup
transformer are rated at 45/60 MVA and have two isolated secondary windings rated 6900 volts and 4160
volts each.

The normal power supply to a unit's auxiliary load is provided through the unit auxiliary transformer connected to the generator bus. This source of power is available except when:

1. The generating unit is in a normal shutdown condition, or
8 2. There is a malfunction or failure preventing continued operation of the
8 reactor-turbine-generator-auxiliary transformer combination.

If power is not available from the unit's generator through the unit's auxiliary transformer, power is
supplied to the unit through its startup transformer fed from either or both of the buses in the 230 kV
switching station. Power to the startup transformer can flow through the 230 kV switching station from
any one of thirteen supplies. These include eight 230 kV transmission circuits, two nuclear generating
8 units if operating, two hydroelectric units and the 525 kV switching station. Each unit's auxiliary startup
transformer is sized to carry full load auxiliaries for one nuclear generating unit plus the engineered
safeguards equipment of another unit. In addition, each unit's startup transformer can backup another
unit's startup transformer through emergency startup buses and dual isolating disconnect switches.

This source of power is available except when:

1. Both of the 230 kV buses in the switching station are unavailable, or
2. There is a 230 kV system blackout, no nuclear generating unit is running, and neither hydro unit is capable of supplying power through the 230 kV connection; or
3. The startup transformer fails or their connection to the 230 kV switching station fails and the unit's auxiliary transformers or their backfeeding circuitry are not available.

2 **8.2.1.3.1 230KV Switching Station Degraded Grid Protection**

8 Two channels of Degraded grid protection (DGP) are provided to assure that the degradation of the
2 voltage from off-site sources does not adversely impact the safety function of safety-related systems and
2 components. Each channel of this system, upon indication of inadequate voltage, will provide an alarm
2 to alert control room personnel of the existence of inadequate voltage in the 230KV switchyard. If an ES
2 signal is sensed by the DGPS, while the voltage is sustained below acceptable levels, the DGPS will
2 initiate an isolation of the 230KV switchyard (yellow bus) and start Keowee so that the on-site emergency
2 overhead power path is available. The non-ES operating units will not be affected by this action. The
2 other units will continue to operate since their generators remain connected to the red bus. It is
2 anticipated that any degradation of the voltage in the 230KV switchyard will not last for an extended
2 period of time. It is recognized that the voltage in the yard needs to be maintained above acceptable
2 levels, and corrective measures would be taken to assure that timely actions are taken to restore the
2 voltage.

7 There are three single phase undervoltage relays installed to monitor the switchyard voltage on X, Y, and
7 Z Phase of the 230KV yellow bus. Each of the undervoltage relays is connected to one of three single
2 phase coupling capacitor voltage transformers. The setpoint of the undervoltage relays considers the
2 minimum analyzed switchyard voltage and the accumulative tolerances of the undervoltage relays and the
2 voltage sensing devices. A time delay is provided to override transients in the offsite system and prevent
2 unnecessary actuation of this protection system.

8.2.1.4 100 kV Switching Station

Whenever there is inadequate power from the generating units, the 230 kV switching station and the
2 hydro units, power is available to the standby power buses either directly from the 100 kV Central Tie
2 Substation or from Lee Steam Station via a 100 kV transmission line connected to 12/16/20 MVA
Transformer CT5 located on the opposite side of the station from the 230 kV facilities. This single 100
kV circuit is connected to the 100 kV transmission system through the substation at Central located eight
miles from Oconee. Central Substation is connected to Lee Steam Station twenty-two miles away
2 through a similar 100 kV line. If an emergency occurs that would require the use of the 100 kV
2 transmission system, this line can either be isolated from the balance of the transmission system to supply
2 emergency power to Oconee from Lee Steam Station, or emergency power can be supplied directly from
2 the 100 kV system from the Central Tie Substation.

8 Degraded voltage protection is provided to protect the essential plant auxiliaries from low voltage on the
8 100 kV system grid. Logic and relaying is installed to alert the operator via an annunciator any time the
8 secondary voltage of transformer CT-5 decreases to such a low value that, if it was the power supply to
8 the main feeder buses and a LOCA/LOOP occurred, proper equipment operation could not be assured.
8 This logic and relaying also "arms" the supply breakers from transformer CT-5 to 4160V Standby Buses
8 #1 & 2 after a time delay. Logic and relaying is also provided which automatically trips the supply
8 breakers from transformer CT-5 to 4160V Standby Buses #1 & 2 if the breakers have previously been
8 armed and the voltage decreases to the trip setpoint.

Located at Lee Steam Station are three 44.1 MVA combustion turbines. One of these three combustion turbines can be started in one hour and connected to the 100 kV line. Transformer CT5 is sized to carry all the engineered safeguards auxiliaries of one unit plus the shutdown loads of the other two units. This source of power is available except:

1. When the 100 kV line or transformer is out of service, or
2. Temporarily after a complete system blackout of all transmission facilities.

8 8.2.1.5 Switching Station 125 Volt DC Power Systems

8 The 230kV switchyard and 525kV switchyard are served by independent 125V DC power systems. Each
8 switching station DC system consists of two 125 volt DC, two conductor, metalclad distribution center
8 assemblies; three battery chargers; and two 125 volt DC batteries. The 230kV switchyard 125V DC
8 system is typical of this arrangement and is shown in Figure 8-7. A bus tie with breakers is provided
between the switchgear bus sections to "backup" a battery when it is removed for servicing. One standby 125 volt dc battery charger is also provided between the two 125 volt dc batteries for servicing. One battery supplies power through panelboards for primary control and protective relaying, and the second battery supplies power through panelboards for backup control and protective relaying. Dual feeds from the redundant panelboards are provided to each Power Circuit Breaker (PCB) for closing and tripping control. Separate dual trip coils are provided for each PCB. For the 230kV switching station PCBs isolating diodes are provided for the redundant power feeds to the common closing coil circuit.

8.2.2 ANALYSIS

Reliability considerations to minimize the probability of power failure due to faults in the network interconnections and the associated switching are as follows:

1. Redundancy is designed into the network interconnections by installing two full capacity transmission circuits for each connection to the 230 kV grid.

2. The two single 230 kV transmission circuits are installed on the same line of double circuit towers. Each line of double circuit towers is separated a safe distance from the others and in most cases installed over a different route.

3. One of the circuits on a line of 230 kV transmission towers is insulated at a higher insulation level than the other, thus minimizing the probability of double outages due to flashovers.

4. Each circuit is protected from lightning and switching surges by an overhead electrostatic shield wire and in addition, lightning arresters are installed at both terminals.

5. The breaker-and-a-half switching arrangement in the 230 kV and 525 kV switching stations includes two full capacity main buses which feed each circuit through a circuit breaker connected to each bus. Completely redundant primary and backup relaying is provided for each circuit along with circuit breaker failure backup protection. These provisions permit the following:

   a. Any circuit can be switched under normal or fault switching without affecting another circuit.

   b. Any single circuit breaker can be isolated for maintenance without affecting any circuit.

   c. Short circuits of a single main bus will be isolated without interrupting service to any circuit.

   d. Short circuit failure of the tie breaker will result in the loss of its two adjacent circuits until it is isolated by disconnect switches.

   e. Short circuit failure of a bus side breaker will result in the loss of the associated bus until it is isolated.

   f. Failure of either the primary protective relaying or the backup protective relaying will not result in the loss of circuit protection.

   With the above protection features, the probability of loss of more than one source of 230 kV or 525 kV power from credible faults is low; however, in the event of an occurrence causing loss of all the 230 kV and 525 kV connections, the station is supplied from one or more of six sources of power, i.e.,
2 the three nuclear units, the two hydro units or the 100 kV line supplied by either the Lee combustion
2 turbines or the Central Tie Substation.

6. The 100 kV transmission line is located above the level of any flood that is postulated on the Keowee River. On the Duke system, wind and ice loadings are more severe than seismic loadings and govern the structural design of transmission lines, including this 100 kV line.

8 7. As shown in Table 8-2, the 125 volt DC switching station power systems are arranged such that a
8 single fault within a system does not preclude the protective relaying and control in the affected
switching station from performing its intended functions.

8.3 ONSITE POWER SYSTEMS

2

8.3.1 AC POWER SYSTEMS

8.3.1.1 System Descriptions

The station distribution system consists of various electrical systems designed to provide reliable electrical power during all modes of station operation and shutdown conditions. The systems are designed with sufficient power sources, redundant buses, and required switching to accomplish this. Engineered safeguard equipment for each unit is arranged onto three load group buses such that the loss of a single bus section for any reason results in only the loss of equipment fed from that bus leaving redundant equipment to perform the same function. In general, the equipment related to unit operation is connected to its respective unit auxiliary electrical buses, whereas equipment common to and serving all units is distributed between the three unit auxiliary electrical buses. The control of power sources and switching for Oconee 1 and 2 is accomplished from the Oconee 1 and 2 control room while control of power sources and switching for Oconee 3 is from the Oconee 3 control room.

8.3.1.1.1 Keowee Hydro Station

The Keowee Hydro Station contains two units rated 87,500 kVA each, which generate at 13.8 kV. Upon loss of power from the Oconee generating unit and 230 kV switchyard, power is supplied from both Keowee units through two separate and independent routes.

One route is a 4000 ft. underground 13.8 kV cable feeder to 12/16/20 MVA Transformer CT4 which
supplies the redundant 4160 volt standby power buses. The underground emergency power feeder is
6 arranged with double air circuit breakers (equipped with low air pressure monitoring switches) so that it
can be connected to either Keowee generator bus. The connection to the generator bus is made with
6 metal-enclosed bus. This under ground feeder is selected at all times to one hydroelectric generator on a
6 predetermined basis and is automatically energized along with Transformer CT4 whenever that generator
is in service in either emergency or normal mode. The underground feeder and associated transformer are
sized to carry full engineered safeguards auxiliaries of one unit plus auxiliaries for safe shutdown of the
other two units.

The second route is a 230 kV transmission line to the 230 kV switching station at Oconee which supplies
each unit's startup transformer. Each Keowee generator is connected to a common 230 kV stepup
6 transformer through a 13.8 kV metal-enclosed bus and synchronizing air circuit breaker equipped with low
6 air pressure monitoring switches.

Each Keowee unit is provided with its own automatic startup equipment located in separate cubicles
within the Keowee control room. The initiation of emergency startup is accomplished by control signals
from either Oconee control area. Normal startup of either unit is by operator action while emergency
startup is automatic. Both units are started automatically and simultaneously and run on standby on
1 either of three conditions: 1) external grid trouble protection system actuation, 2) engineered safeguards
1 actuation or 3) main feeder bus monitor undervoltage actuation. If the units are already operating when
6 any of the above conditions occur, they are separated from the network (and momentarily from the
6 underground path) and continue to run on standby until needed. Each unit's voltage regulator is
equipped with a volts-per-cycle limiting feature which permits it to accept full emergency power load as it

accelerates from zero to full speed within 23 seconds from receipt of the emergency startup initiation signal.

On normal automatic startup, each unit is automatically connected and supplies power to the Oconee 230
6 kV switching station through the stepup transformer by its respective generator air circuit breaker. This is
accomplished by the automatic synchronizing equipment of each unit. On emergency automatic startup,
6 both units are started; the unit with the underground feeder selected to it supplies that feeder and the
6 other unit is available to supply the Oconee 230 kV switching station. If there is a system disturbance,
this unit is connected automatically to the Oconee 230 kV Yellow Bus only after the Oconee 230 kV
2 Yellow Bus is isolated automatically from the system and the preset time delay has elapsed. Redundant
External Grid Trouble Protective Systems are provided to isolate the 230 kV switching station on failure
of the external transmission network. Therefore, on loss of the external transmission network, both of the
Keowee hydro units can provide emergency power to any of the Oconee units through either the 230 kV
switching station to the unit's respective startup transformer or the underground feeder and Transformer
CT4 at Oconee.

Power from the hydro units is available except when:

1. Both units are out of service, or
2. There is a coincident failure of the underground feeder circuit and a complete outage of the 230 kV feeder circuit through the switching station.

9 The Standby Shutdown Facility (SSF) consists of standby systems for use in extreme emergency
9 conditions. Following the loss of all normal and emergency power, on-site and off-site, the SSF diesel
9 electric generating unit will be manually started by initiating the start signal from the SSF Control Panel
9 in the SSF. The SSF Electrical Power System supplies power necessary to maintain hot shutdown of the
9 reactors of each unit, in the event of loss of power from all other power systems.

9 The SSF is described in detail in Section 9.6, "Standby Shutdown Facility." The SSF's role in SBO
9 coping is discussed in Section 8.3.2.2.4, "Station Blackout Analysis."

8.3.1.1.2 6900 Volt Auxiliary System

The 6900 volt auxiliary system for each unit is designed to supply electric power to the 9000 horsepower reactor coolant pump motors. This system is arranged into two bus sections. Both bus sections feed into two switchgear bus sections, each feeding two motors. Each switchgear bus supplies one motor for each of the two reactor coolant piping loops. Either the unit auxiliary or the startup transformer is capable of feeding both switchgear buses. During startup, shutdown and after shutdown, the switchgear buses are supplied from the startup transformer. During normal operation, the switchgear buses are supplied from the unit auxiliary transformer. Normal bus transfers between the two sources are initiated at the discretion of the operator from the control room, while emergency transfer from the unit auxiliary to the startup transformer is initiated automatically by protective relay action. Normal bus transfers used on startup or shutdown of a unit are "live bus" transfers, i.e., the incoming source feeder circuit breaker is closed onto the energized bus section and its interlocks will trip the outgoing source feeder circuit breaker which results in transfers without power interruption. Emergency bus transfers used on the loss of the normal unit source are rapid bus transfers, i.e., the outgoing source feeder circuit breaker is tripped and its interlocks close the incoming source feeder circuit breaker which results in a transfer within a maximum of
nine cycles. An exception to this occurs when the main generator has been supplying in-plant loads while
9 separated from the switching station. In this instance, there is a 1.8 second transfer delay when the
9 normal unit source is lost.

The 6900 volt auxiliary system as shown in Figure 8-1 and Figure 8-3 is similar in arrangement for each of Oconee 1, 2, and 3.

8.3.1.1.3 4160 Volt Auxiliary System

The 4160 volt auxiliary system for each unit is arranged into a double bus - double circuit breaker switching arrangement. The three power sources, (1) the unit's auxiliary transformer, (2) the startup transformer and (3) the standby power buses, feed each of the main feeder buses by this double circuit breaker arrangement. Each of the two redundant main feeder buses provide power to each of the three redundant engineered safeguards switchgear bus sections that serve the engineered safeguards auxiliaries. The engineered safeguards auxiliaries are arranged so that a failure of any single bus section does not prevent the respective systems from fulfilling their protective functions.

The 4160 volt auxiliary system as shown in Figure 8-1 and Figure 8-3 is similar in arrangement for all three units.

On loss of their normal sources of power the 4160 volt main feeder buses are transferred as described for
7 the 6900 volt system (except there is a 1.3 second transfer delay) to alternate sources of power in the
following preferential sequence:

1. Transfer to startup transformer where:
    a. Power is supplied from the 230 kV transmission system, or
    b. Power is supplied from one of the two Keowee hydro units via the 230 kV switchyard.
2. Transfer to 4160 volt standby power buses where:
    a. Standby power is supplied from one Keowee hydro unit via the 13.8 kV underground feeder, or
    b. Standby power is supplied from the 100 kV transmission line.

The control system is designed to prevent the paralleling of two sources during the switching operation and is similar to the transfer systems Duke has used for many years in their fossil-fired plants.

Upon loss of the unit auxiliary transformer source and startup transformer source, and in the absence of an engineered safeguards (ESG) signal, the following occurs:

The turbine-generator and reactor are tripped and the main feeder buses become deenergized. Control power is still available from the dc and vital power systems.

6 Both of the Keowee hydro units are started and the selected unit will be automatically connected to the standby power buses from which power can be supplied to the shutdown auxiliaries.

The non-essential loads are shed.

The equipment required to bring the reactor to a hot shutdown is energized.

Logic and control circuits will be fed without interruption from dc sources and vital power buses.

In the event of a loss of coolant accident requiring engineered safeguards action, the following action takes place:

6 Both Keowee hydro units are started immediately. The unit not selected to the underground feeder is run on standby and connected to the 230 kV Yellow Bus when the bus is isolated.

6 The underground circuit from Keowee becomes automatically energized as the hydro unit to
6 which it is selected is started and breaker control interlocks are satisfied.

The 4160 volt redundant main feeder buses of the unit with the accident are switched to the emergency power sources in the preferential order as described in Section 8.3.1.1.3, "4160 Volt Auxiliary System" (1) and (2).

The engineered safeguards of the unit with the accident are started and the non-essential loads are shed when power is unavailable from the normal or startup sources.

In the event the external transmission network is lost, the following action takes place:

6 Both Keowee hydro units are started immediately and the unit not selected to the 13.8 kV underground feeder is connected automatically to the 230 kV Yellow Bus by closing its respective generator circuit breaker and the 230 kV Power Circuit Breaker (PCB)-9 when the 230 kV Yellow Bus is isolated from the system network.

6 The 230 kV Switchyard Yellow Bus is isolated automatically from the system grid by energizing
2 the dual trip coils of the 230 kV PCBs 8, 12, 15, 17, 21, 24, 26, 28, and 33.

The startup transformers No. CT1, CT2, and CT3 remain connected to the 230 kV switching station.

The 13.8 kV underground circuit from Keowee becomes energized as the hydro unit to which it is connected is started.

In the event of an accident and the simultaneous loss of the external transmission network, the engineered safeguard switchgear buses are supplied emergency power through both 4160 volt main feeder buses from either the 4160 volt startup transformers through their respective feeder breakers or from both of the redundant standby power buses. The standby power buses receive emergency power from either the Keowee Hydro Station or the 100 kV transmission line described in Section 8.3.1.1.3, "4160 Volt Auxiliary System" (2). In the event of a Loss of Coolant Accident (LOCA) any breakers supplying the engineered safeguards loads are closed automatically. In the event of a LOCA and the simultaneous loss of both the normal auxiliary source and the startup source, the non-essential load breakers are tripped. Redundant engineered safeguards load-shedding logic equipment assures positive shedding of non-essential equipment by energizing separate trip coils provided in their circuit breakers. Redundant engineered safeguards actuation channels initiate closing of the essential equipment feeder breakers.

8.3.1.1.4 600 Volt Auxiliary System

Each unit's 600 volt auxiliary system is similar and arranged into multiple bus sections. Each bus section is fed from a separate load center transformer which is connected to one of the three 4160 volt switchgear bus sections. Various 600 volt non-engineered safeguard motor control centers are located throughout the station to supply power to equipment within the related area. The three engineered safeguards load centers and associated motor control centers as shown in Figure 8-4 are redundant and are supplied independently from the three 4160 volt engineered safeguards load buses. Load center X8 and X9 have an alternate feeder with manual transfer to be used when the normal source of power is not available. Each engineered safeguard motor control center has an alternate feeder with manual transfer to be utilized only for maintenance. No common failure mode exists for this system.

8.3.1.1.5 208 Volt Auxiliary System

For each unit, a system is provided to supply instrumentation, control, and power loads requiring unregulated 208Y/120 volt ac power. It consists of motor control centers, distribution panels, and transformers fed from 600 volt motor control centers.

The redundant engineered safeguards 208 volt motor control centers for a unit are shown in Figure 8-4. Each of these motor control centers have redundant supply feeders from separate transformers and redundant 600 volt motor control centers. The feeder breakers have mechanical interlocks and manual transfers.

The 208 volt auxiliary system is similar in arrangement for each of the three units.

8.3.1.1.6 Tests and Inspections

Remote startup of the Keowee generators is provided in each of the control rooms of the nuclear station.
2 Provisions are made in the control rooms to manually initiate an emergency start of both of the two hydroelectric generators connecting the generator to the nuclear station's 4160 volt buses. Testing of this system may be scheduled any time the Keowee hydro units are not running.

8 The 100 kV, 230 kV and 525 kV circuit breakers are inspected, maintained and tested as follows:

1. 100 kV transmission line circuit breakers are tested on a routine basis.
8 2. 230 kV and 525 kV transmission line circuit breakers are tested on a routine basis. This is accomplished without removing the transmission line from service.
8 3. 230 kV and 525 kV switchyard generator circuit breakers may be tested with the generator in service.

Transmission line protective relaying is tested on a routine basis.

Generator protective relaying is tested when the generator is off-line.

The 4160 volt circuit breakers and associated equipment are tested in service by opening and closing the circuit breakers in a manner that does not interfere with the operation of the station. The circuit breakers are "jacked out" to a test position and operated without energizing the circuits, if necessary.

The 600 volt circuit breakers, motor contactors, and associated equipment are tested in service by opening and closing the circuit breakers or contactors so as not to interfere with operation of the station.

Emergency transfers to the various emergency power sources are tested on a routine basis to prove the operational ability of these systems. Associated normal, startup, and standby circuit breakers on one bus can be "jacked out" into test position and initiated manually for an emergency transfer test.

8.3.1.2 Analysis

The emergency electric power system provided for each nuclear generating unit possesses certain inherent design features which improve its reliability over limited capacity split-bus arrangements usually provided in nuclear power plants.

2 The basic design criterion for the electrical portion of the emergency electric power system of a nuclear unit, including the generating sources, distribution system, and controls is that a single failure of any component, passive or active, will not preclude the system from supplying emergency power when required. Special provisions have been employed to accomplish this which include a double bus - double breaker distribution system, redundant circuit breaker trip coils and circuits, diverse protective relaying for each circuit breaker, redundant load shedding and transfer logic equipment, physical separation and other features.

The reliability afforded by the split bus concept is included in the design of the double bus - double breaker system employed here. Consideration has been given to the capacity of the emergency power sources, the method of switching, redundancy utilized and the protective features. For example, the electrical system together with the sources of electric power which are installed to supply emergency power to a nuclear unit possesses the following design features:

1. Each electric power source is extremely large for the requirements. For example, each of the redundant on-site Keowee hydroelectric units is rated 87,500 kVA while the maximum combined load demand on one nuclear unit with a LOCA and the other two nuclear units in a hot shutdown condition is 20,628 kVA as shown in Table 8-1. The smallest of the emergency power sources is the connection to the 100 kV transmission system through Transformer CT-5 which has maximum continuous rating of 22,400 kVA. The significant effect of these large sources of emergency power is that a greater number of plant auxiliaries may be run and used to help cope with an incident as well as shutdown and maintain the other nuclear units in safe shutdown conditions.

2. The Keowee hydroelectric units are inherently reliable sources of power as proven by years of operating experience with similar generating units. Since they are stored energy type machines, their ability to start is very reliable.

   2 Except for the penstock, and cooling water supply pipe to the first valve, shared air supply, static
   2 inverter and regulation, standby battery charger, 4160V and 600V underground power supply to
   2 Keowee through CX, 230 kV main transformer, fire protection system, ACB air system, each unit is <u>entirely independent</u> of the other, consisting of its own turbine, governor system, generator, exciter, voltage regulator, generator circuit breaker, synchronizing equipment, protective relaying, automatic startup control equipment, manual controls, unit dc control battery, etc.

   If one hydro unit is out for maintenance, the other unit is available for service. The two units are served by a common tunnel-penstock, and unwatering for tunnel or scroll case maintenance will make both units unavailable. Based upon Duke's experience since 1919 with a hydro station similarly arranged, it is expected that unwatering frequency will be about one day per year plus four days every tenth year.

   During all periods when the Keowee units are available for emergency power service, the Keowee Hydro Headgate will be rigidly fastened to assure that failure of the hoist system will not permit the gate to move into the closed position.

   The independent Keowee units, along with the alternate circuits, provide the required redundancy to assure reliable emergency power. Storage capacity of the Keowee reservoir and naturally occurring minimum streamflow are such that the generating units can provide continuous emergency power following an accident. The Keowee reservoir, between its normal elevation and maximum planned drawdown, has sufficient storage which, when combined with minimum recorded streamflow on the Keowee River will permit a hydro unit to carry continuously one nuclear unit's emergency auxiliary loads for 126 days.

   The failure analysis covering the Keowee Hydro Station is outlined in Table 8-3.

3. Each electric power distribution system is designed with redundant full capacity buses to match the capacity of the large emergency power source. This thereby provides two continuous sources of supply from the two full capacity main feeder buses to each of the three engineered safeguards switchgear buses.

4. Reliability of the engineered safeguards switchgear buses is assured by the following protective features:

   a. 4160 V engineered safeguards (ESG) switchgear bus overload and bus fault conditions are protected for by both ground fault overcurrent relays and phase overcurrent relays. These relays are provided on each ESG switchgear bus breaker and function to open the associated breaker to isolate the ESG switchgear bus from the main feeder buses, thereby maintaining the integrity of the main feeder buses.

b. Each ESG switchgear feeder breaker is also included in the zone of protection afforded by the main feeder bus differential current relays which would function to isolate a faulted breaker from any source of supply.

c. Each ESG switchgear feeder breaker is provided with breaker failure protective relaying. This feature will initiate action to isolate the breaker from any source of supply if the breaker fails to open upon a protective relay trip. The maximum equipment this would remove from service is one ESG switchgear bus and one main feeder bus, leaving two ESG switchgear buses and the other main feeder bus to supply the required loads which are sufficient to perform the intended safety functions.

d. Each ESG switchgear feeder breaker is provided with redundant trip coils, supplied from separate dc supplies, assuring positive trip action.

With the above protective features plus their metalclad construction and the physical separation maintained, failure of any one of the three redundant ESG switchgear buses or components will not affect the ability of the other two ESG switchgear buses to supply their engineered safeguards loads.

5. Reliability of the main feeder buses and the standby buses is assured by the following protective features:

a. Each main feeder bus and each standby bus is protected independently by differential current relays. These relays will sense any fault condition in the zone between the source side of the incoming bus feeder breakers to the load side of the outgoing feeder breakers. The outgoing feeder breakers on the standby bus are the breakers connecting to the main feeder buses and they have overlapping differential protection from both buses. The outgoing feeder breakers of the main feeder buses are the feeder breakers to the engineered safeguards switchgear buses. If a fault condition occurs, the relays will function to isolate the affected bus from all sources of supply by opening all circuit breakers associated with that bus. The other redundant bus still provides the required power to all three engineered safeguards switchgear buses.

b. Each feeder breaker to each of the buses is protected with phase overcurrent and ground fault overcurrent protective relaying. These relays function to open the breaker and isolate the main feeder bus from the power source upon the occurrence of these overcurrent conditions. This
8 thereby maintains the integrity of the power source and allows the continued supply of power to the other bus and all three engineered safeguards switchgear buses. The comparable condition on a split bus concept would cause the loss of one engineered safeguards bus.

c. Each feeder breaker is also provided with breaker failure protective relaying. This feature will initiate action to isolate the breaker from any source of supply if the breaker fails to open on a protective relay trip. The maximum loss on this condition would be the connected source of supply and the associated bus. The other bus would transfer by the redundant transfer logic to the alternate source of supply and continue supplying power to all three engineered safeguards switchgear buses. The maximum loss under the split bus concept would not only be the source of supply, but also the associated engineered safeguards switchgear bus.

d. Each feeder breaker is provided with redundant trip coils supplied from separate dc supplies, assuring positive trip action.

With the above protective features, their metal-enclosed construction and their physical separation, failure of any one of the redundant bus sections or components will not affect the ability of the other buses to supply the engineered safeguards loads.

6. The emergency power sources are independent of each other and switched on to the main feeder buses such that this independency is maintained. Paralleling of emergency power sources is prevented by redundancy in transfer logic equipment and interlocking.

Redundant systems of emergency power switching equipment are provided to switch the emergency power to the unit's 4160 volt redundant main feeder buses. The redundant transfer logic will seek the most available source of power and when it becomes available close into it. If this source is then
2 subsequently lost, the switching logic and equipment will transfer to the other source automatically if
2 power is available.

The failure analysis covering the emergency electrical systems is outlined in Table 8-4.

8.3.1.3 Physical Identification of Safety-Related Equipment

Detailed cable lists are developed for all cables. These cable lists identify each cable by cable type, specific cable routing by tray section number, and termination points. Protective system cables are identified as such on the cable lists. These lists are issued and are used by the field for cable installation. Each cable tray section, excluding cable trays inside the Reactor Building is identified by tags bearing the tray section number assigned to it. Cables required for protective systems are identified as follows:

1. Power and control cables are color coded to identify their use and/or channel association. The color code is as follows:

9	Gray	Swgr 1TC, 2TC, 3TC
9		Ld Ctr 1X8, 2X8, 3X8
9		MCC 1XS1, 2XS1, 3XS1, 1XSF, 2XSF, 3XSF
9		ESG channel 1, 3, 5, & 7
9		DC Pnlbd 1DIA, 2DIA, 3DIA
9		Vital Pwr Pnlbd 1KVIA, 2KVIA, 3KVIA
9		RPS Ch A
9	Yellow	Swgr 1TD, 2TD, 3TD
9		Ld Ctr 1X9, 2X9, 3X9
9		MCC 1XS2, 2XS2, 3XS2
9		ESG channel 2, 4, 6, & 8
9		DC Pnlbd 1DIB, 2DIB, 3DIB
9		Vital Pwr Pnlbd 1KVIB, 2KVIB, 3KVIB
9		RPS Ch B
9	Blue	Swgr 1TE, 2TE, 3TE
9		Ld Ctr 1X10, 2X10, 3X10
9		MCC 1XS3, 2XS3, 3XS3
9		ESG channel Even-Odd
9		DC Pnlbd 1DIC, 2DIC, 3DIC
9		Vital Pwr Pnlbd 1KVIC, 2KVIC, 3KVIC
9		RPS Channel C
9	Orange	DC Pnlbd 1DID, 2DID, 3DID
9		Vital Pwr Pnlbd 1KVID, 2KVID, 3KVID
9		RPS Ch D

2. All cables have their identifying number permanently affixed to both ends.

8.3.1.4 Independence of Redundant Systems

The physical locations of electrical distribution system equipment shown in Figure 8-1, Figure 8-3 and Figure 8-4 are arranged to minimize vulnerability of vital circuits to physical damage as a result of accidents.

8.3.1.4.1 Auxiliary Transformers

Auxiliary transformers, startup transformers, and the 100 kV transformer are located out of doors and physically separated from each other. Transformer CT4, fed from the on-site Keowee Hydro Station is
8 physically separated from the other transformers and located in a Class I enclosure. Reference Section
3 3.2.1, "Seismic Classification." Surge arresters are used where applicable for lightning protection. All transformers are covered by automatic water spray systems. Transformers are well spaced to minimize their exposure to fire, water, and mechanical damage.

8.3.1.4.2 Switchgear and Load Centers

The 6900 volt switchgear, 4160 volt switchgear, and 600 volt load centers are located in areas to minimize exposure to mechanical, fire, and water damage. This equipment is coordinated electrically to permit safe operation of the equipment under normal and short circuit conditions. Metalclad construction is used throughout for personnel and equipment protection.

The 4160 volt main feeder bus, switchgear sections, and standby power bus switchgear sections are located in a Class I enclosure. The redundant engineered safeguards 4160 volt switchgear bus sections and their associated 600 volt switchgear bus sections, motor control centers, etc. are located within the turbine building and auxiliary building below the operating floor level. They are located in areas with separation and protection to minimize exposure to mechanical, fire and water damage. This equipment is coordinated electrically to permit safe operation under normal and short circuit conditions. The engineered safeguards system is of Class I seismic design.

8.3.1.4.3 Motor Control Centers

The 600 volt motor control centers are located in the areas of electrical load concentration. Those associated with the turbine-generator auxiliary system in general are located below the turbine-generator operating floor level. Those associated with the nuclear steam supply system are located in the auxiliary building. Motor control centers are located in areas with separation and protection to minimize their exposure to mechanical, fire and water damage.

8.3.1.4.4 Batteries, Chargers, Inverters, and Panelboards

The 125 volt dc instrumentation and control power system batteries of a unit are physically separated in separate enclosures from batteries of another unit to minimize their exposure to any damage. The battery chargers and associated dc bus sections and switchgear of a unit are located in separate rooms from battery chargers and associated dc bus sections of another unit in the auxiliary building and physical separation is maintained between redundant equipment.

8.3.1.4.5 Metal-Enclosed Bus

Metal-enclosed buses are used for all major bus runs where large blocks of current are to be carried. They are also routed to minimize exposure to mechanical, fire, and water damage.

8.3.1.4.6 Cable Installation and Separation

8.3.1.4.6.1 Cable Installation

Loadings and stresses in the cable tray and hangers were examined under both the steady state and seismic conditions. Hanger type HC-18, which is one of the most heavily laden hangers, was checked. It
3 supports eleven to twelve trays vertically, some of which are overfilled.

Original hanger calculations were based on the assumption that all hangers would be loaded at 200 pounds per tray. Under those conditions maximum stresses reached in any hanger member are 382 psi during steady state conditions and 11,100 psi under seismic loadings. This stress occurred in the angle brace which was added due to lateral seismic forces. Since the material for hangers and braces used is rated at 25,000 psi allowable (Reference 1), hangers are stressed at less than 50% of their allowable loading under the worst conditions.

3 Calculations were made using existing loadings on one of the heaviest loaded HC-18 hangers. Detailed inventory lists of all cables in each tray section have been maintained, and from this list it was determined that the hanger was loaded as follows:

Level H (top)	112.6 pounds
G	155.0 pounds
F	282.0 pounds
E	364.0 pounds
D	194.5 pounds
C	149.5 pounds
B	97.0 pounds
A (bottom)	196.0 pounds

Calculations with these loads show that stresses reached were 373 psi under steady state conditions and 11,000 psi during an earthquake. These stresses are actually slightly lower than the original calculation. This is due to several factors. First, although some trays are loaded heavier than the assumed 200 pounds per foot, some of the trays are considerably under the 200 pounds per foot. Secondly, many of the tray sections which are volumewise overfilled are not overloaded from a weight standpoint because Oconee control cables have generally been randomly placed in the tray which has caused many voids to exist.

Overfilled trays were examined and it was determined that section 1ME8 contains 120.4 pounds of cable per linear foot. The tray manufacturers' safe load chart (Reference 2) states that 24 inch tray with 9 inch rung spacing will support a load of 215 pounds per foot <u>with</u> a 2.2 safety factor. The tray used has an ultimate strength of 473 pounds (2.2 x 215). With an existing load of 120.4 pounds the minimum safety factor is 3.8. Therefore, the present tray system is capable of supporting the weight of the cable even with the existing overfilled conditions and the additional fire retardant barriers.

8.3.1.4.6.2 Cable Separation

Control, instrumentation, and power cables are applied and routed to minimize their vulnerability to damage from any source.

2 Our criteria for routing cables requires that mutually redundant safety related cables be run in separate trays. Trays are spaced vertically in the cable room a minimum of 10 inches apart and in some cases redundant cables are in vertically adjacent trays. It should be pointed out that the cable armors used provide excellent mechanical and fire protection which would not be provided with conventional, unarmored cable systems. An early warning fire detection system has also been provided in this area.

Wire and cables related to engineered safeguards and reactor protective systems are routed and installed to maintain the integrity of their respective redundant channels and protect them from physical damage. Power and control cables for redundant auxiliaries or services are run by different routes to reduce any probability of an accident disabling more than one piece of redundant equipment. Floor sleeves are filled with a fire retardant material.

It is our intent wherever physically possible to utilize metallically armored and protected cables systems. By this we mean the use of rigid and thin wall metal conduit, aluminum sheath cables, bronze armored control cables, steel interlocked armor power and control cables, and either interlocked armor or served wire armored instrumentation cables. With this type construction fire stops as such are not required.

Where overfill situations exist in Oconee 1 between vertically adjacent cable trays to the extent that the top cable in the lower tray is within three inches of the bottom cable in the tray immediately above, a one-eighth of an inch fire retardant fiberglass reinforced polyester barrier will be placed between the trays.
7 The fire retardant fiberglass reinforced polyester is used as an insulator and protection mechanism to
7 prevent an electrical short from contacting a nearby tray. This product was used due to its good electric
7 insulating characteristics and its low additional combustible load contribution. These barriers will be
attached to the bottom of the upper tray and fitted around cables which may pass through the barrier.

A minimum of five inches rail to rail separation will be maintained between all vertical trays on Oconee 2 and 3.

8.3.1.5 Cable Derating and Cable Tray Fill

8.3.1.5.1 Cable Derating

All cables are selected using conservative margins with respect to their current carrying capacities, insulation properties, and mechanical construction. Cable insulations in the Reactor Building are selected to minimize the effects of radiation, heat, and humidity. Appropriate instrumentation cables are shielded to minimize induced voltage and magnetic interference.

7 Power cables are derated based on IEEE S-135, ICEA (Insulated Cable Engineers Association),
7 Publication No. P-46-426, recommendations for interlocked armor power cables when installed in cable
7 support systems.

Studies of heating due to I^2R loss in the cables were made. It was determined that the worst case was tray section 1ME8 which contained 322 cables. Cables were classed in three groups: control, control power and instrumentation. Losses were determined by conservative means and were found to be a total of 1.3 watts per lineal foot of tray. Assuming that one cable dissipates 36% of the total heat and that this cable is in the center of a nine inch pile of cable, its maximum temperature would be only 14°C above the ambient cable spreading room temperature, even though the insulation qualities of the cable pile were assumed to be almost perfect. No air flow was assumed through the cables; therefore, the addition of barriers does not alter the heating calculations. Due to the small amount of heat generated and since all cable used in this area is rated 90°C, these temperatures will have no detrimental affect on adjacent cables or on cables in other trays.

Temperature measurements have been made periodically at ten selected locations for the first-year of operation. These locations are where the tray over-fill is the most severe.

Overload protection for cables is very closely related to the basic power and control systems designs. The 4 kV power systems are protected by electro-mechanical overcurrent relays and solid state type ground relays. The relays are selected for the loads protected and the cables are sized based on the maximum currents which these relays should allow without tripping for the loads they are protecting. The 600 volt load centers are used to feed individual motor control centers. The feeder breakers used are furnished with long-time and instantaneous electromechanical or short-time trip elements. Cables to each breaker are sized in coordination with the trip elements selected for that particular breaker. Small motor loads at the 600 volt and 208 volt levels are generally handled through combination motor starters located in motor control centers. Short circuit protection for the load is provided by molded case circuit breakers with magnetic trip devices while overcurrent protection is provided by standard starter overload elements sized for the application. On small engineered safeguard motor loads two of the three overload elements are oversized for cable protection rather than motor protection and are wired in the contactor trip circuit.

The third element is sized for motor protection but is wired to alarm only. This is based on the premise that the motor should operate even if motor damage does occur. Cable sizing is based on maximum service factor loading of the motor.

8.3.1.5.2 Cable Tray Fill

Early cable tray requirements were based on types of cable which had been used in the past which were primarily not armored. Armored cable was used at Oconee to achieve better mechanical protection and fire retardance. This caused the trays to fill faster than anticipated and in several locations the fill became excessive. Steps have also been taken to insure that no additional cables are routed through trays which are already overfilled.

7 The cable tray spacing criterion for those trays containing power cables is based on ICEA, Publication
7 No. P-46-426 recommendations for interlocked armor power cables when installed in cable support
7 systems.

8.3.2 DC POWER SYSTEMS

8.3.2.1 System Descriptions

For each nuclear unit, two separate dc power systems are provided; namely, a 125 volt dc system provides
a source of reliable continuous power for control and instrumentation for normal operation and orderly
shutdown for each unit, and a separate 125/250 volt dc system is provided to supply large power loads for
7 each unit. These systems are shown in Figure 8-5 and Figure 8-9. For each Keowee hydro unit,
separate and independent dc power systems are provided to assure a source of reliable continuous power
for normal and emergency operation. These systems are shown in Figure 8-6.

8.3.2.1.1 125 Volt DC Instrumentation and Control Power System

For each unit, two independent and physically separated 125 volt dc batteries and dc buses are provided for the vital instrumentation and control power system. The dc buses are two conductor metalclad distribution center assemblies. Three battery chargers are also supplied, with two serving as normal supplies to the bus sections with the associated 125 volt dc battery floating on the bus. The batteries supply the load without interruption should the battery chargers or the ac source fail. Each of the three battery chargers are supplied from the redundant 600 volt ac engineered safeguards motor control centers of each unit. One of these three battery chargers serves as a standby battery charger and is provided for servicing and to backup the normal power supply chargers. A bus tie with normally open breakers is provided between each pair of dc bus sections to "backup" a battery when it is removed for servicing.

Four separate 125 volt dc instrumentation and control panelboards are also provided for each unit. Each panelboard receives its dc power through an auctioneering network of two isolating diode assemblies. One assembly is connected to the unit's 125 volt distribution system and the other assembly is connected to another unit's 125 volt distribution system. The functions of the diode assemblies are to discriminate between the voltage level of the two dc distribution systems, to pass current from the dc system of higher potential to the instrumentation and control panelboard connected on the output of the diode assemblies, and to block the flow of current from one dc distribution system to the other.

Each isolating diode assembly is composed of a series-parallel network of four diodes in each polarity leg of the dc supply to the panelboard it serves. With this series-parallel arrangement of diodes, either an open circuited or short circuited diode can be tolerated without affecting the operability of the diode assembly. The individual diodes are sized for a continuous current of 500 amperes with the maximum panelboard load current being 304 amps. Each diode is also rated for continuous operation with a peak inverse voltage of 800 volts.

Continuous monitoring of each diode is provided in the design of each isolating diode assembly to detect a shorted or open circuited diode. Since each individual monitor is connected across the diode it monitors, a complete failure analysis was conducted to assure that a failed component in the monitor does not prevent the detection of diode trouble. Factory tests are conducted to check monitor operability under varying voltage levels. The monitors are designed to operate continuously without component failure with a back voltage of 50 volts continuous or 800 volts for 10 seconds. Since the battery under-voltage relay alarms are 123 vdc, only a voltage difference between battery voltages (back voltage) less than 9 volts can occur undetected, and, with one battery in the network completely discharged, the back voltage seen by an isolating diode assembly would be 25 volts. With a back voltage of 25 volts on a monitor assembly, the current flow from battery system to battery system would be less than 0.5 amps.

An alarm relay, connected to an individual control room annunciator point, is provided in each isolating diode assembly to advise the operator of diode trouble in the particular assembly in difficulty. The alarm system is designed to be void of nuisance tripping.

Test provisions are included in each isolating diode assembly to allow the in-service checking of the operability of individual diode monitors, and, in addition, to allow the out of service periodic checking of the peak inverse voltage capability of each individual diode. The latter test can be conducted on one isolating diode assembly with the other diode assembly in the network in operation. Breakers on the input and output of each isolating diode assembly are provided for complete isolation during maintenance and testing of an assembly.

8.3.2.1.2 125/250 Volt DC Station Power System

For each unit a separate 125/250 volt dc power system is supplied. Each system consists of three 125/250 volt dc power supply battery chargers, a three conductor, metalclad distribution center assembly, and two
9 125 volt dc batteries. This arrangement provides 125 volts dc from "P" bus to "PN" bus, 125 volts dc
9 from "PN" bus to "N" bus, and 250 volts dc from "P" bus to "N" bus. Loads on this system are
basically the 250 volt dc power loads of units. Each 125 volt dc half of a bus section normally is supplied from one of the 125 volt dc power supply battery chargers with the associated 125 volt dc battery floating on the bus. The batteries supply the load without interruption should the battery charger or the ac source fail. A bus tie with normally open double breakers is provided between the three units' distribution center bus sections to backup a battery when it is removed for servicing. One standby 125 volt dc power supply battery charger is provided between each pair of the 125 volt dc batteries for servicing and to "backup" the normal power supply battery chargers.

8.3.2.1.3 125 Volt DC Keowee Station Power System

For each Keowee hydro unit a separate 125 volt dc power system is supplied. Each system consists of one 125 volt dc power supply battery charger, one 125 volt dc, two conductor, metalclad distribution center assembly and one 125 volt dc battery. A bus tie with normally open double circuit breakers is provided between the two distribution center bus sections to "backup" a battery when it is removed for servicing. One standby 125 volt dc battery charger is also provided between the two 125 volt dc batteries
8 for servicing. The batteries, battery charger and distribution center associated with one unit are located in
8 the same room as those associated with the other unit, but are physically separated from those associated
8 with the other unit by different enclosures.

8.3.2.1.4 120 Volt AC Vital Power Buses

Figure 8-5 shows the arrangement of the 120 volt ac vital power buses. For each unit, four redundant 120 volt ac vital instrument power buses are provided to supply power in a predetermined arrangement to vital power, instrumentation, and control loads under all operating conditions. Each bus is supplied separately from a static inverter connected to one of the four 125 volt dc control power panelboards described in Section 8.3.2.1.1, "125 Volt DC Instrumentation and Control Power System." Upon loss of power from 125 volt dc bus DCA or DCB, the affected inverter is supplied power from a 125 volt dc bus
2 of another unit through dc control power panelboards and transfer diodes of the affected 125 volt dc
2 panelboard. A tie with breakers is provided to each of the 120 volt vital ac buses from the alternate 120 volt ac regulated bus to provide backup for each vital bus and to permit servicing of the inverters. Each inverter has the synchronizing capability to permit synchronization with the regulated buses.

For each unit, each of the four redundant channels of the nuclear instrumentation and reactor protective system equipment is supplied from a separate bus of the four redundant buses. Also for each unit, each of the three redundant channels of the engineered safeguards protective system is supplied from a separate bus of the four redundant buses. The two engineered safeguards actuation power buses are supplied from separate vital power buses.

8.3.2.1.5 240/120 Volt AC Uninterruptible Power System

For each unit, four uninterruptible power systems are provided to supply power.

They are:

1. The unit's Integrated Control System (ICS) power system, which is 120 volt ac, single phase.
2. The unit's Auxiliary Power System (APS) which is 120 volt ac, single phase.
3. The unit's original design Computer Power System (CPS), which is 240/120 volt ac, single phase.
4. The units' new Computer Power System (KOAC), which is 240/120 volt ac, single phase.

Each of these first three systems consist of a static inverter, with redundant 125 volt dc supplies from separate 125 volt dc buses, circuit breakers and distribution panelboards. The fourth system consists of a static inverter with a 250 volt dc supply from a single 250 volt dc bus, circuit breaker, and distribution panelboard. Also, a static transfer switch is provided in each system as a means for automatic transfer of system loads to the alternate ac regulated power system should the inverter become unavailable. The output of each inverter is synchronized with the ac regulated power system through the static switch in order to minimize transfer time from inverter to the regulated supply.

7 In addition, an automatic transfer switch is provided in the ICS, APS, and CPS power systems as a means for automatic transfer of system loads to the alternate ac regulated power system should the static transfer switch become unavailable.

8.3.2.1.6 240/125 Volt AC Regulated Power System

For each unit, a system is provided to supply instrumentation, control, and power loads requiring regulated ac power. It also serves as an alternate power source to both the vital power panelboards and to the uninterruptible power panel boards. The system consists of two distribution panels, two regulators,
7 and two transformers fed from separate motor control centers. These systems are shown in Figure 8-5.

8.3.2.1.7 Emergency Lighting System

For each unit, two separate emergency lighting systems are provided; namely, an Emergency 250 Volt DC Lighting System and a separate Engineered Safeguards 208Y/120 Volt AC Lighting System. These two systems are separate and distinct.

8.3.2.1.7.1 Emergency 250 Volt DC Lighting System

The 250 Volt DC Lighting System, which is normally de-energized, provides operating level lighting in the
8 control room and lighting at selected areas in the Auxiliary, Turbine, Reactor, Administrative and Service
8 Buildings. The emergency lighting is energized automatically by an undervoltage sensing relay mounted on the individual panelboards located in their associated areas. Control power for the undervoltage transfer circuit is provided from the 250 volt dc station batteries. A test button is also provided at each panelboard to test the operability of the system without affecting normal lighting. All associated lighting units are incandescent.

8.3.2.1.7.2 Engineered Safeguards AC Lighting System

The Engineered Safeguards AC Lighting System, which is normally de-energized, provides lighting in the following parts of the Auxiliary Building: control room, cable room, equipment room, stairs, exits, corridors, hot machine shop, spent fuel pool room, fuel unloading area, decontamination rooms, pump and tank room areas, fan and ventilation rooms of roof elevation, penetration rooms, and purge rooms. The stairs and platforms in the Reactor Building are also provided lighting to enable personnel to leave or enter the entire building. Power is provided from two engineered safeguards 600 volt ac control centers through two 600/208Y/120 volt ac dry type transformers which in turn feed each of two panelboards located in the equipment room area. The engineered safeguard lighting is energized automatically by undervoltage sensing relays monitoring the normal 600 volt ac feeder voltage.

8.3.2.1.8 DC and AC Vital Power System Monitoring

Failure and/or misoperation of all dc and ac vital power system equipment is being monitored on two local alarm annunciators located in the equipment room near most of the vital equipment. Several variables within each piece or redundant group of equipment are being monitored on one of the local
4 panels, with any alarm from each group being retransferred to a common group alarm in the control
9 room. Although not considered a failure or misoperation, ground conditions on the vital dc system are
9 provided an alarm in the control room. The control room alarms alert the operator if an alarm condition occurs on any piece or group of equipment, or if power is lost to the local alarm monitoring equipment.

The DC bus tie breakers, battery breakers and standby charger breaker position indication contacts; the standby charger trouble contact; and the computer, ICS and auxiliary inverter isolating diode trouble contacts are monitored directly in the control room.

The other vital alarms are divided into two separate and independent monitoring systems. Alarms for equipment which have battery 1CA for their primary source of power are maintained physically and electrically separate from battery 1CB powered equipment. For example, the distribution center, isolating diodes, breakers, panelboards, inverters and transfer switches associated with battery 1CA are alarmed on local and remote annunciators which are physically and electrically separated from the annunciators being used for monitoring battery 1CB associated systems.

Specifically, the variables being monitored locally with a composite alarm from each of the 17 groups being taken to the control room are as follows:

Group 1 and 11 for each of the two dc buses

9

Charger trouble

Charger output breaker tripped

Bus voltage low (123 V dc)

Group 2, 3, 4, 5, 12, 13, 14, 15 for each of eight isolating diodes

Fuse blown

Diode failure

Input breaker open

Output breaker open

Feeder breaker open

Group 6, 7, 16, 17 for each of four vital inverters and panelboards

4 Inverter input voltage low

Inverter output voltage low

Bypass voltage low

Inverter bypassed

Panelboard voltage low (60%)

Group 8, 18, 19 for computer, ICS and auxiliary inverters and panelboards

4 Inverter input voltage low

Inverter output voltage low

Bypass voltage low

Inverter bypassed

Panelboard voltage low (60%)

8.3.2.2 Analysis

The 125 Volt DC Instrumentation and Control Power System and the 125 Volt AC Vital Power System are designed such that upon loss of power supplies no interactions exist between Reactor Protection Systems, Engineered Safeguards Protection Systems, and control systems that would preclude these systems from performing their respective functions. Also, any interactions between units as a result of the loss of power supplies does not preclude the safety and control systems of any unit from fulfilling their function. This is verified by safety analyses and is shown in Table 8-5, Table 8-6, and Table 8-7.

9 The ungrounded dc system has a ground detector with a manually switched backup to indicate when there is a ground existing on any leg of the system. A ground on one leg of the dc system will not cause any equipment to malfunction. Simultaneous grounds on two legs of the system may cause all energized equipment to drop out if the grounds are of sufficiently low resistance. This may be momentary if the grounded circuit is cleared by its circuit breaker or sustained if the grounded circuit is not cleared by its
1 circuit breaker.

Each battery is sized to carry the continuous emergency load for a period of one hour in addition to
2 supplying power for the operation of momentary loads during the one hour period. The Station Blackout
3 (Section 8.3.2.2.4, "Station Blackout Analysis") coping strategy which manually strips non-essential loads
2 from the 125 Volt I&C Power System within 30 minutes into the event allows for the operation of the
2 equipment required during the scenario for four hours.

In normal operation the batteries are floated on the buses, and assume load without interruption on loss of a battery charger or ac power source.

The lead-acid batteries are tested to prove their ampere-hour capacity. Inservice periodic checks of the status of each cell is made through battery hydrometer log readings and cell voltage. Temperature readings are used to adjust hydrometer readings.

8.3.2.2.1 Single Failure Analysis of the 125 Volt DC Instrumentation and Control Power System

As shown in Table 8-5, the 125 Volt DC Instrumentation and Control Power System is arranged such that a single fault within either system does not preclude the Reactor Protective System, Engineered Safeguards Protective System, and the engineered safeguards equipment from performing their safety functions.

8.3.2.2.2 Single Failure Analyses of the 125 Volt DC Keowee Station Power System

The 125 Volt DC Keowee Station Power System is arranged such that a single fault within either unit's system does not preclude the other unit from performing its intended function of supplying emergency power.

8.3.2.2.3 Single Failure Analysis of the 120 Volt Vital Power Buses

The 120 Volt Vital Power System is arranged such that any type of single failure or fault will not preclude the Reactor Protective System, Engineered Safeguards Protective System, and engineered safeguards equipment from performing their safety functions. There are four independent buses available to each unit, and single failure within the system can involve only one bus. A single failure analysis is presented in Table 8-6.

3 8.3.2.2.4 Station Blackout Analysis

3 Station Blackout (SBO) is the hypothetical case where all off-site power and both Keowee hydro-electric
3 units are lost. Electrical power is available immediately from the battery systems and within 10 minutes
3 from the SSF diesel generator. This event was originally included in FSAR section 15.8.3. As
3 documented in the NRC Safety Evaluation Report (SER) dated March 10, 1992 and the NRC
3 Supplemental SER dated December 3, 1992, Oconee Nuclear Station is in compliance with 10 CFR 50.63
3 and conforms to the guidance of NUMARC Report 8700 and Regulatory Guide 1.155. This regulation
3 requires that a licensed nuclear power plant demonstrate the ability to achieve safe shutdown from 100%
3 reactor power by ensuring containment integrity and adequate decay heat removal for a calculated
3 duration. The licensee must also demonstrate that the required equipment be able to withstand the
3 resulting operating environment. The temperature of the control room and other areas where extensive
3 manual operations occur, shall not exceed habitability requirements of 120°F. Station blackout is not a
3 design basis event. Therefore, the SBO scenario is not concurrent with any design basis event or single
3 failures.

3 Oconee is capable of coping with a SBO by the following means:

3 1. The SBO duration is 4 hours by application of NUMARC 8700 guidance.

3 2. The SSF is the alternate AC (AAC) source.

3 3. The SSF Auxiliary Service Water system is the design basis source of decay heat removal. Actuation
3 of the Emergency CCW System is not required since the inventory in the CCW piping is sufficient for
3 4 hour operation of the SSF/ASW system.

3 4. The non-essential inverters (KI, KU, and KX) are manually stripped from the Vital 125VDC System
3 within 30 minutes to reduce the electrical heat loads of the unit control complex. Refer to FSAR
3 Selected Licensee Commitment 16.8.1. The resulting temperature in the unit control room does not
3 exceed the habitability requirement of 120°F. Therefore, command and control remain in the unit
3 control room to allow completion of restoration procedures as required in the Supplemental SER
3 dated December 3, 1992.

3 5. Containment isolation valves fail closed on loss of air or power, can be manually closed, or have
3 diverse closure ability from the SSF as required in NUMARC 8700.

8 6. Restoration of power is accomplished by manual closure of switchgear breakers at Switchgear control
8 panel.

8 Stripping the non-essential inverters from the 125VDC system will make power available to the
8 TDEFWP and its associated controls in the unit control room for 4 hours. Although its operability is
8 limited to 2 hours due to the volume of the associated nitrogen supply. Notably, the TDEFWP is not
8 required for the 4 hour coping period since the SSF ASW system is the licensing and design basis
3 commitment for decay heat removal during the SBO event.

3 The 4 hour coping duration is derived from NUMARC 8700 based on meteorological data, grid stability,
3 switchyard features, and availability/reliability of emergency power sources. A program to control SSF
3 availability/reliability has been implemented to ensure at least a value of 95% as stated in the
9 Supplemental SER. The program is based on the largest single contributor of SSF unavailability, which
9 is unwatering of Unit 2 CCW intake piping. This is based on the fact that Unit 2 CCW intake piping
9 supplies suction to the SSF Auxiliary Service Water pump, the diesel engine cooling and the SSF HVAC.
9 SSF availability is also dependent on the reliability of Keowee, the SSF batteries, the SSF diesel generator
9 and supporting systems. Additionally, controls are implemented so that planned maintenance on the SSF
3 and Keowee does not occur simultaneously.

8.3.3 REFERENCES

1. Unistrut Corporation General Engineering Catalog No. 6, 1966, Page 11.
2. Unistrut Corporation Catalog KUR4P-2, Page 16.

8.4 ADEQUACY OF STATION ELECTRIC DISTRIBUTION SYSTEM VOLTAGES

8.4.1 ANALYSIS

Each offsite power source was analyzed to the onsite distribution system under maximum and minimum load conditions with the offsite power sources at maximum and minimum anticipated voltages. The analysis included the transient effects on the Class 1E equipment from starting a large Class 1E and non-Class 1E load. The maximum voltage expected at the 4kV bus is slightly higher than the equipment rating. However, this voltage does not have detrimental effects on plant loads or motor feeder circuits. When voltage drops are accounted for, the maximum equipment terminal voltage is within the equipment rating. The minimum analyzed bus voltages shown in the analysis are high enough to account for feeder voltage drops that exist between the bus and the loads. The minimum equipment terminal voltage is within the equipment rating. It has been established that the 4160 volt, 600 volt and 208 volt emergency loads will operate within allowable voltage limits when supplied from the offsite power system.

8 Tests were performed in accordance with NRC guidelines for verification of voltages and currents for the Unit 3 distribution system while the unit auxiliary transformer of that unit supplied 100% of the normal full power operating loads. The measured voltage values were compared with calculated voltage values, and in all cases, the measured values were acceptably close to the analyzed voltage values (0.21-0.28% for the 4 kV buses; within 0.33% for 600 volt buses; and within 1.05 to 1.73% for the 208 volt buses). This test verifies the accuracy of the analysis for the steady-state condition. The verification tests on Unit 3 are applicable to Units 1 and 2 also, since they employ identical equipment and distribution systems. Therefore, no separate tests are required on Units 1 and 2.

8.4.2 CONCLUSIONS

1. The voltages are within the operating limits of Class IE equipment for projected combinations of plant load and offsite power grid conditions provided one startup transformer is used for one unit.
2. Spurious separation from the offsite power system due to the operation of voltage protective relays will not occur (with the offsite grid voltage within its expected limits) as a result of starting safety loads.
3. It has been determined (by analysis) that no potential for either a simultaneous or consequential loss of both offsite power sources exists.

8.4.3 REFERENCES

1. J. F. Stolz (NRC) to H. B. Tucker, Letter, Review of Adequacy of Station Electric Distribution System Voltages for Oconee Nuclear Station, Units Nos. 1, 2, and 3 (enclosing NRC SER and EG&G TER) Washington, D.C., March 1983.

2 **THIS IS THE LAST PAGE OF THE CHAPTER 8 TEXT PORTION.**

Table 8-5 (Page 2 of 3). Single Failure Analysis for 125 Volt DC Instrumentation and Control Power System

		Component	Malfunction		Comments & Consequences
2 2 2 2	6.	125V DC Distribution Center DCA, DCB	Gradual decay of voltage on one bus	(a)	Each 125 volt bus is monitored to detect the voltage decay on the bus and initiate an alarm at a setting above a voltage where the battery can deliver power for safe and orderly shutdown of the station. Upon detection, power will be restored either by correcting the deficiency by switching to a redundant source or by employing one of the redundant circuits.
2 2	7.	DC Distribution Center Load Feeder Cables	Cables shorted	(a)	Same comments as 3a and 3b.
5					
	8.	Isolating Diodes	Failure of one	(a)	If the diode fails "shorted" then the other series diodes will still provide adequate isolation and power will be uninterrupted.
				(b)	If the diode fails "open" then the other redundant supply through its isolating diodes will continue to supply power without interruption.
9 9 9 9 9	9.	125V DC Control Power Panelboard 1DIA, 1DIB, 1DIC, 1DID, 2DIA, 2DIB, 2DIC, 2DID, 3DIA, 3DIB, 3DIC or 3DID	Bus shorted	(a)	Voltage on two of the 125 volt dc bus systems will decay until isolated by the isolating circuit breakers causing consequences same as comments 3a and 3b. At most, one panelboard in a single unit could be lost.
2 9 9 9 9 9 9 9				(b)	For one unit, one-half of control and instrumentation power not associated with reactor instrumentation and protective systems or engineered safeguards will be degraded until the shorted panel board isolates, after which one-fourth of the loads would be lost. Control and instrumentation power associated with reactor instrumentation and protective systems or engineered safeguards is covered in 9(g).
2				(c)	For one unit, one-half of 6900 volt switchgear closing control power could be lost but dual trip coils and redundant tripping power supplies are provided.

Table 8-5 (Page 3 of 3). Single Failure Analysis for 125 Volt DC Instrumentation and Control Power System

	Component	Malfunction		Comments & Consequences
2			(d)	For one unit, one-third of the 4160 volt switchgear closing control power could be lost. Dual trip coils and redundant tripping control power are provided. The remaining redundant switchgear is adequate and is supplied control power from the other dc panels.
2			(e)	For one unit, the 4160 volt main feeder bus circuit breakers on only one of the two buses could lose closing control. All 4160 volt circuit breakers have redundant trip coils and power supplies. The remaining main feeder bus and circuit breakers are supplied control power from the other dc panels, permitting the switching of 4160 volt emergency power to any unit.
9 9 9 9 9 9			(f)	For one unit, the 600 volt load center(s) associated with the affected panel will lose dc control power; however, each load connected to the load center(s) has an alternate feed from a redundant load center.
			(g)	One static inverter would be lost and power to one instrument bus would be lost temporarily until a manual transfer could be made to a regulated instrument bus. The temporary loss of one vital instrument bus would result in the temporary loss of one channel of reactor protection and instrument systems and engineered safeguards systems. Other remaining channels will receive vital instrument control power from the other panelboards.

Table 8-6. Single Failure Analysis for the 120 Volt AC Vital Power System

		Component	Malfunction		Comments & Consequences
    9 9 9 9 9	1.	125V DC Control Power Panelboard 1DIA, 1DIB, 1DIC, 1DID, 2DIA, 2DIB, 2DIC, 2DID, 3DIA, 3DIB, 3DIC or 3DID	Bus shorted		One static inverter would be lost and power to one instrument bus would be lost temporarily until a manual transfer could be made to a regulated instrument bus. The temporary loss of one vital instrument bus would result in the temporary loss of one channel of reactor protection and instrument systems and engineered safeguards systems. Other remaining channels will receive vital instrument control power from the other panelboards.
	2.	Static Inverter Feeder Cable	Failure		Same as comment 1.
	3.	Static Inverter	Failure		Same as comment 1.
    9 9 9 9 9 9 9 9	4.	Vital Instrument Power Panelboard 1KVIA, 1KVIB, 1KVIC, 1KVID, 2KVIA, 2KVIB, 2KVIC, 2KVID, 3KVIA, 3KVIB, 3KVIC or 3KVID	Failure of one	(a)	For any one bus failure only one channel of any system associated with reactor instrumentation and protective systems or engineered safeguards would be lost. Sufficient redundant channels supplied from other vital instrument buses would provide adequate protection.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 9. AUXILIARY SYSTEMS

The Auxiliary Systems required to support the reactor during normal operations and servicing of the Oconee Nuclear Station are described in this section. Some of these systems have also been described and discussed in Chapter 6, "Engineered Safeguards," since they serve as engineered safeguards. The information in this section deals primarily with the functions served by these systems during normal operation.

The design of the Auxiliary Systems has included consideration of system sharing, where feasible, between the three Oconee Nuclear Station units. This section describes the equipment for each unit and states where equipment is shared.

The majority of the components in these systems are located within the Auxiliary Building. Those systems connected by piping between the Reactor Building and the Auxiliary Building are equipped with Reactor Building isolation valves as described in Chapter 6, "Engineered Safeguards."

9.1 FUEL STORAGE AND HANDLING

9.1.1 NEW FUEL STORAGE

7 New fuel will normally be stored in the spent fuel pool serving the respective unit. New or irradiated fuel
7 assemblies with initial nominal enrichments up to 5.00 weight percent U-235 which do not meet the
7 requirements for unrestricted storage must be placed in a restricted loading pattern.

9 **Note:** New fuel is temporarily being administratively restricted to 4.10 weight percent or less due to the
9 current operable but degraded status of the spent fuel pools (Ref. PIPs O-00-0969 and
9 O-99-01247). This conservative limit ensures that the limit of $K_{eff} < 0.95$ will be met.

7 Reactivity analyses for these assemblies, stored in every other row of the spent fuel pool, were performed
7 using the methods discussed in Section 9.1.2.3.2, "Criticality Analysis." Acceptable fuel assemblies which
9 qualify for storage in the alternating rows between restricted assemblies are referred to as filler assemblies.

New fuel may also be stored in the fuel transfer canal. The fuel assemblies are stored in five racks in a row having a nominal center-to-center distance of 2 ft 1-3/4 inches. One rack is oversized to receive a failed fuel assembly container. The other four racks are normal size and are capable of receiving new fuel assemblies.

New fuel may also be stored in shipping containers.

9.1.2 SPENT FUEL STORAGE

9.1.2.1 Spent Fuel Storage - Oconee 1, 2

The Spent Fuel Pool common to Oconee Units 1 and 2 has been re-racked to increase the spent fuel storage capacity to 1312 fuel assemblies through the use of neutron absorbing racks. This modification is pursuant to License Amendment Nos. 90, 90 and 87 for License Nos. DPR-38, DPR-47 and DPR-55 for the Oconee Nuclear Station.

9.1.2.1.1 Design Bases

The Spent Fuel Pool designed for Oconee 1 and 2 is an integral part of the Oconee 1 and 2 Auxiliary Buildings and conforms to Safety Guide 13, "Fuel Storage Design Basis." The fuel pools were designed
7 for tornado wind and missiles, turbine generator missile, and seismic conditions as listed in Table 3-23.
The Spent Fuel Pools were analyzed for the postulated cask drop accident as described in Section 3.8.4.4, "Design and Analysis Procedures."

The spent fuel pool is constructed of reinforced concrete lined with stainless steel plate. The fuel pool concrete, reinforcing steel, liner plate and welds connecting the liner plate to the fuel pool floor concrete embedments are analyzed based on consideration of the new racks and additional fuel. Design criteria including loading combinations and allowable stresses are in compliance with Oconee FSAR Section 3.8.4, "Other Seismic Class I Structures" for Class I structures. The determination of Ta (abnormal thermal load condition to be used in combination with E′) is based on the failure of one pump or cooler during normal operating conditions.

The function of the spent fuel storage racks is to provide for storage of spent fuel assemblies in a flooded pool, while maintaining a coolable geometry, preventing criticality, and protecting the fuel assemblies from excess mechanical or thermal loadings.

A list of design criteria is given below:

1. The racks are designed in accordance with the "NRC Position for Review and Acceptance of Spent Fuel Storage and Handling Applications," dated April 14, 1978 and revised January 18, 1979.
2. The racks are designed to meet the nuclear requirements of ANSI N210-1976. The effective multiplication factor, K_{eff}, in the spent fuel pool is less than or equal to 0.95, including all uncertainties and under all credible conditions.
3. The racks are designed to allow coolant flow such that boiling in the water channels between fuel assemblies does not occur.
4. The racks are designed to Seismic Category 1 requirements, and are classified as ANS Safety Class 3 and ASME Code Class 3 Component Support structures.
5. The racks are designed to withstand loads which may result from fuel handling accidents and from the maximum uplift force of the fuel handling crane.
6. Each storage position in the racks is designed to support and guide the fuel assembly in a manner that will minimize the possibility of application of excessive lateral, axial and bending loads to fuel assemblies during fuel assembly handling and storage.
7. The racks are designed to preclude the insertion of a fuel assembly in other than design locations.
8. The materials used in construction of the racks are compatible with the storage pool environment and do not contaminate the fuel assemblies

9.1.2.1.2 Design Description

The Oconee fuel storage racks are composed of individual storage cells made of stainless steel interconnected by grid assemblies to form integral module structures as shown in Figure 9-1. Each cell has a lead-in opening which is symmetrical and is blended smooth to facilitate fuel insertion. The cells are open at the top and bottom to provide a flow path for convective cooling of spent fuel assemblies through natural circulation. The fuel assembly storage cells are structurally connected to form modules through
8 the use of plates and box beams which limit structural deformations and maintain a nominal center-to-center spacing between adjacent storage cavities during design conditions including the Safe Shutdown Earthquake. The racks utilize a neutron absorber, Boraflex, which is attached to each cell. The modules are neither anchored to the floor nor braced by the pool walls. The following information applies to the Oconee 1 and 2 fuel storage pool.

	Number of Cells	1312
	Number of Modules	4 - 8 x 11 10 - 8 x 12
5	Poison Material	Boraflex 0.02 gm B^{10}/cm^2 Vented to pool environment
	Center-to-Center Spacing	10.65 in.
5 5 5	Type of Fuel	B&W 15 x 15, MK B11 and earlier designs, 5.0 weight percent maximum nominal enrichment

8	Approx. Rack Assembly Dimension and Max Weights	8 x 11 85.5 x 117 x 176 - 24,200 lbs.
8		8 x 12 - 85.5 x 128 x 176 - 26,100 lbs.

The pool outline and rack arrangements are shown in Figure 9-3 and Figure 9-4.

9.1.2.2 Spent Fuel Storage - Oconee 3

The Spent Fuel Pool serving Oconee Unit 3 has been re-racked to increase the spent fuel storage capacity
5 to 822 fuel assemblies, plus 3 additional storage spaces for failed fuel containers, through the use of neutron absorbing racks. This modification is pursuant to License Amendment Nos. 123, 123, and 120 for License Nos. DPR-38, DPR-47 and DPR-55 for the Oconee Nuclear Station.

9.1.2.2.1 Design Bases

The Oconee 3 Spent Fuel Pool has the same Design Bases as the Oconee 1 and 2 pool described in Section 9.1.2.1.1, "Design Bases."

9.1.2.2.2 Design Description

The Oconee 3 Spent Fuel Pool storage racks are similar to the Oconee 1 and 2 racks described in Section 9.1.2.1.2, "Design Description." The following information applies to Oconee Unit 3 spent fuel storage racks.

5 5	Number of Cells	822 plus storage locations for 3 failed fuel containers
	Number Rack Arrays	7 - 8 x 10
		2 - 8 x 12 1 - 8 x 10 x/3 container locations
5 5	Poison Material	Boraflex 0.03 gm B^{10}/cm^2 Vented to pool environment
	Center-to-Center Spacing	10.60 in.
5 5 5	Type of Fuel	B&W 15 x 15, MK B11 and earlier designs, 5.0 weight percent maximum nominal enrichment.
8 8	Approximate Rack Assembly Dimension and Maximum Weights	8 x 10 - 85.5 x 107 x 172 - 18,060 lbs.
8 8		8 x 12 - 85.5 x 128 x 172 - 21,800 lbs.

The pool outline and rack arrangements are shown in Figure 9-3 and Figure 9-4.

5 9.1.2.3 System Evaluation

5 9.1.2.3.1 Structural and Seismic Analysis

Fuel assembly storage rack and associated structures are designed to withstand the maximum forces generated during normal operation combined with the Safe Shutdown Earthquake according to the requirements of a Seismic Class 1 structure. For these conditions, the storage rack design is such that all stresses fall within the allowable stress limits specified in the AISC Specifications for Design, Fabrication and Erection of Structural Steel.

Normal operating loads include dead weight (in air) and thermal expansion loads. Lateral and vertical seismic loads along with the fluid forces generated by seismically generated pool water sloshing are considered to be acting simultaneously.

The seismic input spectra conform to the requirements of Regulatory Guide 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants."

Reference is made to Project 81 PSAR, Docket Nos. STN50-488 through -493, Section 3.7, "Seismic Design." The smoothed response spectra shown on Figure 2E-2A were normalized to 10 percent g for Safe Shutdown Earthquake (SSE). An earthquake acceleration-time history compatible with these spectra, as shown in Figures 2E-2B through 2E-2E, was used as a base motion on the model of the Auxiliary Building.

The seismic response of the Auxiliary Building to the base excitation is determined by a dynamic analysis. The dynamic analysis is made by idealizing the structure as a series of lumped masses with weightless elastic columns acting as spring restraints. The base of the structure is considered fixed. The choice of the location of the mass-joints depends on the distribution of masses in the real structure.

8 The seismic analysis of the racks was performed in two phases:

8 First a seismic time history analysis of a simplified non-linear 2-dimensional model was conducted. The
8 model consisted of spring, mass, damping, friction, and gap elements to simulate a fuel bundle in a
8 simplified model of a rack. The fuel assembly-to-cell impact loads, support pad lift-off values, rack
8 sliding, and overall rack response were determined from the non-linear analysis. Coefficients of friction
8 were varied between minimum and maximum possible values in order to determine worst case conditions
8 of sliding and tipping respectively. Rack-to-rack impacts were precluded by spacing the racks beyond
8 maximum possible excursion. The gap spaces are large enough to accomodate lateral module motion due
8 to earthquake forces. In order to account for 3-dimensional effects, the results of independent orthogonal
8 loadings were combined by the SRSS method.

8 Next, a seismic response spectrum analysis of a 3-dimensional finite element model of the racks, using
8 inputs from the results of the non-linear analysis, and superimposed with other applicable loads, was
8 conducted. Design stresses and safety margins for appropriate components in the racks were tabulated
8 and found to be acceptable.

8 The structural damping values used are 4 percent for an SSE and 2 percent for an OBE.

The maximum uplift load available from the fuel handling crane on the storage rack is limited to 3000 lbs
8 or less by the hoist interlock. A separate fuel assembly drop analysis was performed. A 3000 pound
8 object was postulated to impact the top of the rack from a height of 6 feet. Calculations show that the
8 resulting stresses are within acceptable stress limits.

Structural design precludes placing a fuel assembly between cells, and the rack will withstand the loadings imposed by a postulated dropped fuel assembly.

5 **9.1.2.3.2 Criticality Analysis**

5 The design methodology which ensures the criticality safety of the fuel assemblies in the spent fuel storage
5 rack is discussed in Section 9.1.2.3.2.3, "Criticality Analysis Methodology" and in Reference 8.

5 *9.1.2.3.2.1 Neutron Multiplication Factor*

5 Criticality of fuel assemblies in the spent fuel storage rack is prevented by the design of the rack which
5 limits fuel assembly interaction. This is done by fixing the minimum separation between assemblies and
5 inserting neutron poisons between assemblies.

5 The design basis for preventing criticality outside the reactor is that, including uncertainties, there is a 95
5 percent probability at a 95 percent confidence level that the effective multiplication factor (k_{eff}) of the fuel
5 assembly array will be less than 0.95 for most conditions (0.98 for certain accident conditions) as
5 recommended in ANSI/ANS-57.2-1983 and in Reference 9. The acceptance criteria for criticality is
5 further discussed in Section 9.1.2.3.2.5, "Acceptance Criteria for Criticality."

5 *9.1.2.3.2.2 Normal Storage*

5 Under normal storage conditions, the following assumptions were used in the criticality analysis.

5 1. Credit is taken for the decrease in reactivity associated with the fuel assembly burnup.

5 2. The fuel assembly is the most reactive fuel assembly to be stored based on a minimum burnup. The
5 fuel designs analyzed are all 15x15 arrays and include up through the Babcock and Wilcox MkB11
5 design.

5 3. The moderator is pure water at the temperature within the design limits of the pool which yields the
5 largest reactivity. No dissolved boron is included in the water for normal storage in the spent fuel
5 pool racks. Credit is taken for soluble boron under postulated accident conditions and during fuel
5 movement. For accident conditions the double contingency principle of ANSI N16.1-1975 is applied.
5 This principle states that it shall require at least two unlikely, independent, and concurrent events to
5 produce a criticality accident. During fuel movement the presence of dissolved boron in the spent fuel
5 pool water is assumed since this is only a temporary condition and only a single assembly is handled
5 at a time.

5 4. The array is either infinite in the lateral extent or is surrounded by a conservatively chosen reflector,
5 whichever is appropriate for the design. The nominal case calculation is infinite in the lateral extent.
5 However, poison plates are not necessary on the periphery of the modular array and between widely
5 spaced modules because calculations show that this finite array is less reactive than the nominal case
5 infinite array. The assemblies are also infinite in the axial extent. The 2 dimensional infinite array
5 assumption is consistent with other burnup credit analyses performed by the spent fuel storage cell
5 vendor. The vendor studied the differences between a detailed 3-D model which included the effects
5 of axial burnup, and an infinite 2-D model which did not. The conclusion reached was that the
5 reactivity differences were relatively small and that the infinite 2-D model conservatively bounded the
5 results of the 3-D model with axial burnup effects for the typical range of minimum burnup
5 requirements. Therefore, the nominal case of a 2 dimensional infinite array of poison cells is a
5 conservative assumption.

5 5. Mechanical uncertainties and biases due to mechanical tolerances during construction are treated by
5 either using "worst case" conditions or by performing sensitivity studies and obtaining appropriate
5 values. The items included in the analysis are:

5 - Boraflex thickness

5 - Boraflex width

5 - Can ID

5 - Stainless steel thickness

5 - Center-to-center spacing

- Fuel enrichment
- Fuel pellet density
- Fuel pellet OD

Other applicable uncertainties and biases are discussed in Section 9.1.2.3.2.3, "Criticality Analysis Methodology."

6. No credit is taken for the assembly spacer grids.
7. No credit is taken for fuel assembly control components which can be removed (e.g. burnable poisons and control rods).
8. Credit is taken for the inherent neutron absorbing effect of some of the rack structure materials and in solid materials added specifically for neutron absorption in accordance with Section 6.4.2.2.8 of ANSI/ANS-57.2-1983.
9. A bias is included in the reactivity calculation to account for B_4C particle self shielding.

9.1.2.3.2.3 Criticality Analysis Methodology

Criticality of fuel assemblies outside the reactor is precluded by adequate design of fuel transfer, shipping and storage facilities and by administrative control procedures. The two principal methods of preventing criticality are limiting the fuel assembly array size and limiting assembly interaction by fixing the minimum separation between assemblies and/or inserting neutron poisons between assemblies.

The design basis for preventing criticality outside the reactor is that, considering possible variations, there is a 95 percent probability at a 95 percent confidence level that the effective multiplication factor (k_{eff}) of the fuel assembly array will be less than or equal to 0.95 as recommended in ANSI N210-1976. The conditions that are assumed in meeting this design basis are outlined in Section 9.1.2.3.2.2, "Normal Storage."

In order to justify storage of fuel up to 5.0 w/o, the burnup credit approach was utilized in the spent fuel pools. The burnup credit approach to fuel rack criticality analysis requires calculation and comparison of reactivity values over a range of burnup and initial enrichment conditions. In order to accurately model characteristics of irradiated fuel which impact reactivity, a criticality analysis method capable of evaluating arrays of these irradiated assemblies is needed. The advanced nodal methodology combining CASMO-3/TABLES-3/SIMULATE-3 is used for this purpose. CASMO-3 (Reference 4) is an integral transport theory code, SIMULATE-3 (Reference 6) is a nodal diffusion theory code, and TABLES-3 (Reference 5) is a linking code which reformats CASMO-3 data for use in SIMULATE-3. This methodology permits direct coupling of incore depletion calculations and resulting fuel isotopics with out-of-core storage array criticality analyses. The variable effects of fission product poisoning, fissile material production and utilization and other related effects are accurately modeled with the CASMO-3/TABLES-3/SIMULATE-3 methodology. Applicable biases and uncertainties are developed and become inputs to the methodology.

The results for the criticality methodology are validated by comparison to measured results of fuel storage critical experiments. The criticality experiments used to benchmark the methodology were the Babcock and Wilcox close proximity storage critical experiments performed at the CX-10 facility (Reference 7). The B&W critical experiments used are specifically designed for benchmarking reactivity calculation techniques. The experiments are analyzed, and the statistical accuracy of the calculated reactivity results are assessed.

The bias associated with the benchmarks is -0.00189 Δk with a standard deviation of 0.00371 Δk. The 95/95 one-sided tolerance limit factor for 10 values is 2.911. Therefore, there is a 95 percent probability at

5 a 95 percent confidence level that the uncertainty in reactivity due to the method is not greater than
5 0.01080 Δk.

5 For burned fuel, the maximum reactivity occurs approximately 100 hours after shutdown due to the decay
5 of Xe^{135}. Therefore, all fuel assemblies in the spent fuel pool are modeled at no xenon conditions.

5 An additional bias and uncertainty are required to quantify the reactivity of burned nuclear fuel
5 assemblies. Two burnup uncertainties associated with this methodology are accounted for in the
5 criticality analysis. The first penalty accounts for uncertainties in the reactivity due to uncertainties in the
5 burnup of the assembly, while the second penalty accounts for the reactivity holddown effect of lumped
5 burnable absorbers.

5 The exposure reactivity uncertainty accounts for the uncertainty on the assembly burnup. Since the final
5 burnup qualification curves are based on a code calculated burnup, the uncertainty in that calculated
5 burnup must be considered. Rather than determining the uncertainty on the actual burnup, the
5 uncertainty on reactivity due to burnup was applied to account for the burnup uncertainty. A 95/95
5 one-sided tolerance was determined to account for the maximum reactivity error associated with the
5 burnup of the fuel.

5 As required by the standards, no removable poisons are accounted for in the criticality analyses. Thus, all
5 assemblies are modeled with no burnable poisons (BPs). However, this can be slightly non-conservative
5 due to the increase in reactivity associated with the removal of the BP. Thus a burnable poison removal
5 (BP-Pull) penalty is developed to account for this effect. BPs are used in the core design to hold down
5 reactivity, and hence peaking of fresh assemblies. Thus, the reactivity of the BPd assembly is less than the
5 non-BPd assembly. However, once the BP is removed from the previously BPd assembly, a reactivity
5 increase is seen due to the shadowing effect the BPs had on the assembly. This reactivity increase is large
5 enough such that the assembly with the BPs removed is more reactive than the assembly which never
5 contained BPs, once the BPs are removed. This difference in reactivity is applied as an additional bias on
5 reactivity.

5 The basic approach in the burnup credit methodology is to use reactivity equivalencing techniques to
5 construct burnup versus enrichment curves which represent equivalent and acceptable reactivity conditions
5 over an applicable range of burnups and initial enrichments. These burnup versus enrichment curves are
5 established for each type of storage, e.g. unrestricted and restricted storage.

5 Generation of the applicable burnup credit curves requires a two part calculation process. The first part is
5 to create two types of reactivity versus burnup curves. The first type of curve defines the maximum
5 reactivity for the spent fuel pool such that the appropriate design criteria are met including allowances for
5 both calculational uncertainties and manufacturing tolerances. The second type of curve represents the
5 reactivity versus burnup for a particular enrichment, and is generated for the range of enrichments. The
5 intersection of the maximum design reactivity curve with the multiple enrichment curves provides data
5 points for the second part of the process.

5 The second part of the process generates the burnup versus initial enrichment curves by plotting the
5 burnup where the maximum design reactivity equals the reactivity of a particular enrichment for each
5 enrichment. Two curves are generated which represent the qualification criteria for a particular storage
5 configuration. Each burnup versus enrichment curve shows the minimum amount of burnup required to
5 qualify fuel for storage in the applicable loading pattern as a function of the fuel's initial enrichment.
5 Additional details of the methods used can be found in Reference 8.

5 The SCALE-4 system of computer codes (Reference 10) was used to analyze the boundary condition
5 created between the restricted and unrestricted storage configurations to assure that the storage

5 configurations at the boundary do not cause an increase in the nominal k_{eff} for the individual regions.
5 This analysis is performed to determine if there is a need for new administrative restrictions at the
5 boundaries.

7 This methodology utilizes two dimensional Monte Carlo theory. Specifically, this analysis method used
7 the CSAS25 sequence contained in Criticality Analysis Sequence No. 4 (CSAS4). CSAS4 is a control
7 module contained in the SCALE-4.2 system of codes. The CSAS25 sequence utilizes two cross section
7 processing codes (NITAWL and BONAMI) and a 3-D Monte Carlo code (KENO Va) for calculating the
7 effective multiplication factor for the system. The 27 Group NDF4 cross section library was used
7 exclusively for this analysis.

5 Acceptable interface boundary conditions between storage configurations were determined by varying the
5 boundaries between various storage regions to determine the worst case configurations for coupling
5 between assemblies in different regions. The boundaries were then reflected to simulate an infinite array.
5 The k_{eff} of these infinite boundary arrays were compared to the base k_{eff} of infinite arrays of either fuel
5 storage region creating the boundary. If the infinite boundary array k_{eff} did not represent an increase in the
5 k_{eff} of the regions making the boundary, then no storage restrictions were imposed at the interface. When
5 the worst case did represent an increase, conservative storage restrictions were applied.

5 These methods conform with ANSI N18.2-1973, "Nuclear Safety Criteria for the Design of Stationary
5 Pressurized Water Reactor Plants," Section 5.7, Fuel Handling System; ANSI N210-1976, "Design
5 Objectives for LWR Spent Fuel Storage Facilities at Nuclear Power Stations," Section 5.1.12; ANSI
5 N16.9-1975, "NRC Standard Review Plan," Section 9.1.2, "Spent Fuel Storage" and the NRC guidance
5 contained in Reference 9.

5 *9.1.2.3.2.4 Postulated Accidents*

5 Most accident conditions will not result in an increase in k_{eff} of the rack. Examples are loss of cooling
5 systems and dropping a fuel assembly on top of the rack. For the loss of cooling systems, the reactivity
5 decreases with decreasing water density for the Oconee spent fuel storage racks and the current analyzed
5 fuel designs. For an assembly dropped on top of the storage rack, the rack structure pertinent for
5 criticality is not excessively deformed and the dropped assembly has more than eight inches of water
5 separating it from the active fuel height of stored assemblies which precludes interaction. Although the
5 dropped assembly is more reactive outside rather than inside the poisoned storage cell, the assembly is no
5 more reactive dropped on top of the storage rack than located anywhere else in the pool outside the
5 storage rack.

5 However, accidents can be postulated which would increase reactivity. For accident conditions, two
5 techniques are employed to ensure that sufficient criticality margin exists, the double contingency principle
5 and increasing the K_{eff} limit to 0.98. The acceptance criteria for criticality is further discussed in
5 9.1.2.3.2.5, "Acceptance Criteria for Criticality."

5 The double contingency principle of ANSI/ANS-57.2-1983 states that it is not required to assume two
5 unlikely, independent concurrent events to ensure protection against a criticality accident. Thus, for
5 accident conditions, the presence of soluble boron in the storage pool water can be assumed as a realistic
5 initial condition since not assuming its presence would be a second unlikely event.

5 The presence of approximately 2000 ppm boron in the pool water will decrease reactivity by about 20
5 percent Δk. In perspective, this is nearly as much negative reactivity as in the poison plates, so k_{eff} for the
5 rack would only be slightly greater than 0.95 even if the poison plates were not present. Thus, for
5 postulated accidents, should there be a reactivity increase, k_{eff} would be less than or equal to 0.95 due to
5 the combined effects of the dissolved boron and the poison plates.

5 Increasing the k_{eff} limit to 0.98 provides an additional 0.03 Δk margin for accident conditions. This still
5 provides 0.02 Δk margin to criticality as required in ANSI/ANS-57.2-1983 Section 6.4.2.2.3.

5 The "optimum moderation" accident is not a problem in the spent fuel storage racks because possible
5 water densities are too low ($\leq$ 0.01 gm/cm^3) to yield k_{eff} values higher than for full density water and the
5 rack design prevents the preferential reduction of water density between the cells of a rack (e.g. boiling
5 between cells). Further, the presence of the poison plates removes the conditions necessary for "optimum
5 moderation" so that k_{eff} continually decreases as moderator density decreases from 1.0 g/cm^3 to 0.0 g/cm^3
5 in poison rack designs.

5 *9.1.2.3.2.5 Acceptance Criteria for Criticality*

5 The neutron multiplication factor in the spent fuel pools shall be less than or equal to 0.95, including all
5 uncertainties. Under certain accident conditions K_{eff} may be less than or equal to 0.98 as permitted by
5 ANSI/ANS-57.2-1983.

5 Generally, the acceptance criteria for postulated accident conditions can be $k_{eff} \leq 0.98$ because of the
5 accuracy of the methods used coupled with the low probability of occurrence. For instance, in ANSI
5 N210-1976 the acceptance criteria for the "optimum moderation" condition is $k_{eff} \leq 0.98$. However, for
5 storage pools which contain dissolved boron, the use of the realistic initial conditions provides additional
5 subcriticality margin below 0.98. Thus, the acceptance criteria for most conditions in the spent fuel pools
5 will be $k_{eff} \leq 0.95$. This assumes credit may be taken for soluble boron under accident conditions as
5 allowed by the double contingency principle in ANSI/ANS-57.2-1983, and that no credit is taken for
5 soluble boron under normal conditions.

5 For certain accident conditions, the less restrictive 0.98 limit on k_{eff} is applied. Examples of this include
5 the cask drop accident in Section 15.11.2.5.1, "Criticality Analyses for Dry Storage Transfer Cask Drop
5 Scenarios" and makeup to the spent fuel pool with unborated water following a Standby Shutdown
5 Facility event.

5 *9.1.2.3.2.6 Cask Drop Accident*

5 Cask drop accidents are analyzed for criticality consequences in Section 15.11.2.5.1, "Criticality Analyses
5 for Dry Storage Transfer Cask Drop Scenarios."

5 **9.1.2.3.3 Material, Construction, and Quality Control**

7 The entire fuel assembly storage rack is constructed of type 304 stainless steel, with Boraflex panels
7 attached to each cell. All welded construction is used in the fabrication of the fuel assembly storage rack.
The all-welded construction ensures the structural integrity of the storage modules and provides assurance
of smooth, snag-free passage in the storage cavities so that it is highly improbable that a fuel assembly
could become stuck in the rack.

7 The material, construction and quality control procedures are in accordance with the quality assurance
requirements of Duke Power Company, as described in Duke Power Company Topical Report,
DUKE-1.

5 **9.1.2.3.4 Interface of High Capacity Fuel Storage Rack and Spent Fuel Storage Pool**

The pool floor will support the high capacity storage rack as a free-standing structure during all design
8 conditions. During installation, no racks are moved over spent fuel assemblies in the pool. All spent fuel
8 assemblies in Unit 3 are removed prior to removing existing racks.

For the free-standing rack structure, conservative analysis shows that under simultaneous forces from
8 vertical and lateral seismic excitation, the residual displacement of the rack relative to the pool floor is less
8 than 1 inch for full-loaded condition (i.e., much less than minimum clearance of 2.75 inches to pool walls
and installed equipment.)

8 The maximum sliding distance of the Westinghouse free-standing fuel rack is obtained by equating the
8 kinetic energy developed in the fuel rack, in response to the SSE seismic event, to the energy dissipated by
8 friction between the fuel rack supports and the pool floor, during sliding. The maximum kinetic energy in
8 the fuel rack, produced by the SSE seismic event, is calculated from the spectral response to the SSE
8 response spectrum. The horizontal displacement of the rack is 1.414 times the sum of the deflecton of the
8 top of the rack (0.245 in) and the maximum sliding distance (0.432). The coefficient of friction is assumed
8 to be 0.20.

The rack/pool floor normal force on which the lateral friction forces used in the analysis are based
8 includes the effect of vertical seismic acceleration.

8 The maximum lateral seismic force exerted by any rack module on pool floor is 189000 pounds and
8 results in a stress of 2440 psi in the floor liner and 3296 psi in the weld connecting the floor liner to
embedments in the concrete. The maximum combined seismic and thermal stress in the floor liner is
8 21640 psi and 30610 psi in the weld between liner and embedments. The maximum stresses are below the
8 design allowable stress of 27,000 psi in the liner and 32000 psi in the welds.

5 9.1.2.4 Safety Evaluation

The storage rack is designed and constructed to retain the integrity of the structure under all anticipated loads, including the Safe Shutdown Earthquake, with the maximum number of fuel assemblies occupying the storage locations.

The rack design provides protection against damage to the fuel and precludes the possibility of a fuel
assembly being placed between cells. Although not required for safe storage of spent fuel assemblies, the
7 spent fuel pool water is normally borated to a concentration as specified by the Core Operating Limits
7 Report (COLR). The rack design also assures a K_{eff} of less than 0.95 even when the entire array of fuel
5 assemblies, assumed to be in their most reactive condition and within the limits specified in the Technical
5 Specifications, are immersed in unborated water at room temperature. Furthermore, if the pools were
5 filled with the most reactive fuel allowed, which is clearly in violation of the Technical Specifications, K_{eff}
5 would be $\simeq$ 0.8 with credit for soluble boron. Under these conditions a criticality accident during
refueling or storage is not considered credible.

9 9.1.2.5 Boraflex

9 The spent fuel storage racks contain Boraflex, which is the trade name for a silicon polymer that contains
9 a specified amount of Boron 10 that is used as the neutron absorber to assure that the design basis for
9 criticality control is met through the service life of the racks. The Boraflex is affixed to each of the four
9 exterior sides of the fuel storage cell by means of stainless steel wrappers. Boraflex is used in spent fuel
9 storage racks for the nonproductive absorption of neutrons such that the NRC established acceptance
9 criterion of k_{eff} no greater than 0.95 is maintained.

9 In the NRC Safety Evaluations approving the use of these racks, the NRC concluded that tests under
9 irradiation and at elevated temperatures in borated water indicate that the Boraflex material will not
9 undergo significant degradation during the expected service life of 40 years.′ Based on the above
9 information, Duke has conservatively determined that the aging of Boraflex meets the criteria of Section
9 54.3 and should be considered as a time-limited aging analysis for the purposes of license renewal.

9 Oconee has had in place a Boraflex Monitoring Program since the installation of the high density spent
9 fuel storage racks containing Boraflex. This program contains several elements including testing,
9 monitoring, and analysis of the criticality design. Actions are taken as necessary to assure that the NRC
9 established acceptance criterion of k_{eff} no greater than 0.95 is maintained.

9 The Spent Fuel Rack Boraflex Monitoring Program monitors the Boraflex to assure that the required 5%
9 criticality margin is maintained for the lifetime of the spent fuel storage racks. The program includes:

9 1. Periodic neutron attenuation testing of a representative sample of actual Boraflex panel enclosures to
9 established appropriate acceptance criteria;

9 2. Periodic sampling and analysis for silica in the spent fuel cooling water and the trending of results
9 obtained;

9 3. Corrective actions to be taken in the event the Boraflex is no longer capable of maintaining the
9 required subcriticality margin.

9 Data collection and analysis of Boraflex condition is implemented through Nuclear Generation
9 Department administrative and workplace procedures.

9 From the license renewal review, it was determined that the above activities will effectively manage the
9 Boraflex during the period of extended operation.

9.1.3 SPENT FUEL COOLING SYSTEM

9.1.3.1 Design Bases

2 **9.1.3.1.1 Units 1 and 2 Spent Fuel Pool Cooling System**

5 The primary function of Spent Fuel Pool Cooling System for Units 1 and 2 is to provide decay heat
2 removal for the spent fuel stored in the Units 1 and 2 spent fuel pool. The cooling system design
5 requirements are the criteria imposed by the 1980 re-racking (References 11, 12). Other system functions
2 are to maintain the pool inventory, clarity and chemistry at acceptable levels.

5

5 Revised criteria have been imposed during the 1980 re-racking modification, pursuant to Amendments 90,
90, and 87 for License Nos. DPR-38, DPR-47 and DPR-55 for the Oconee Nuclear Station. The
5 thermal-hydraulic analyses associated with the spent fuel pool racks assumes that the bulk spent fuel pool
7 temperature remain at or below 150°F, for normal heat loads (Reference 11). The Units 1 and 2 Spent
Fuel Cooling System is designed to keep the pool bulk water temperature:

5 1. Below 150°F for normal heat loads and two or three pump-cooler configurations in operation
5 (Reference 11)

5 2. Below 150°F for abnormal heat loads and three pump-cooler configurations in operation (Reference
5 11)

5 3. Below 205°F for abnormal heat loads and any two pump-cooler configurations in operation
5 (Reference 11).

For the Units 1 and 2 spent fuel cooling system, the design basis normal heat load assumes that Units 1
and 2 are refueled consecutively, and the rack positions are filled with previous discharges, except for 118
5 spaces reserved for a full core discharge (Reference 11). The design basis abnormal heat load assumes that
Units 1 and 2 are refueled consecutively, followed by a full core discharge after a short period of

5 operation. In this case, all rack positions contain spent fuel (References 11 and 12). The decay heat
5 predictions are to be based on the methodology presented in Reference 13.

5 It should be noted that, while all temperature conditions above represent design criteria associated with
5 specific analytical assumptions, only the higher temperature of 205°F represents an actual operating limit.
5 Analyses have been performed to ensure that seismic and structural integrity of the pool liner, supporting
5 concrete, and fuel racks are not compromised at this temperature limit. Thermal - hydraulic analysis of
5 the racks has also shown that boiling within the fuel cells does not occur with pool temperatures
5 maintained at or below this limit, provided normal operating pool level is maintained.

2 In addition to the primary function of decay heat removal, the system provides for purification of the
2 spent fuel pool water, the fuel transfer canal water, and the contents of the borated water storage tank, in
2 order to remove fission and corrosion products and to maintain water clarity for fuel handling operations.
2 The system also provides inventory makeup for the fuel transfer canal and the incore instrument handling
2 tank.

2 The system is designed to withstand the effects of a seismic event and meet the requirements of Quality
2 Group C classification.

2 **9.1.3.1.2 Unit 3 Spent Fuel Pool Cooling System**

2 The Unit 3 Spent Fuel Pool Cooling System duplicates the equipment used for the Units 1 and 2 system.
2 The Unit 3 system is designed to remove the decay heat from the stored fuel in the Unit 3 spent fuel pool.
5 The cooling system heat removal requirements are as set forth in NRC Standard Review Plan Section
5 SRP-9.1.3 (References 14, 15). Other system functions are to maintain the pool inventory, clarity and
2 chemistry at acceptable levels.

5

2 The Unit 3 system heat removal design requirements, as stipulated by Standard Review Plan 9.1.3, are:

2 1. For the maximum normal heat load with the normal cooling systems in operation, and assuming a
2 single active failure, the temperature of the pool water shall be maintained at or below 140°F and the
2 liquid level in the pool should be maintained.

2 2. For the abnormal maximum heat load with the normal cooling systems in operation, the pool water
2 temperature should be kept below boiling and the liquid level in the pool should be maintained. A
2 single active failure need not be considered.

5 The design basis maximum normal and abnormal decay heat loads are as defined in SRP 9.1.3 (Reference
5 15), for fuel racks with greater than 1 1/3 core storage capacity. The decay heat predictions are to be
5 based on the methodology presented in Reference 13.

5 It should be noted that, while both temperature conditions above represent design criteria associated with
5 specific analytical assumptions, only the boiling criterion represents an actual design limit. An operating
5 limit of 205°F is imposed for conservatism. Analyses have been performed to ensure that seismic and
5 structural integrity of the pool liner, supporting concrete, and fuel racks are not compromised at this
5 temperature limit. Thermal - hydraulic analysis of the racks also has shown that boiling within the fuel
5 cells does not occur with pool temperatures maintained at or below this limit, provided normal operating
5 pool level is maintained.

2 In addition to the primary function of decay heat removal, the system provides for purification of the
2 spent fuel pool water, the fuel transfer canal water, and the contents of the borated water storage tank, in
2 order to remove fission and corrosion products and to maintain water clarity for fuel handling operations.

2 The system also provides inventory makeup for the fuel transfer canal and the incore instrument handling
2 tank.

2 The system is designed to withstand the effects of a seismic event and meet the requirements of Quality
2 Group C classification.

9.1.3.2 System Description

0 The Spent Fuel Cooling System (Figure 9-5, Units 1, 2 and 3) provides cooling for the spent fuel pool to remove fission product decay heat energy. System performance data are shown in Table 9-1 (Units 1 and 2) and Table 9-2 (Unit 3). Major components of the system are briefly described below.

Spent Fuel Coolers

The spent fuel coolers are designed to maintain the temperature of the spent fuel pool as noted in Section 9.1.3.1, "Design Bases." There are three coolers for Oconee 1 and 2, and three coolers for Unit 3, arranged in parallel.

Spent Fuel Coolant Pumps

The spent fuel coolant pumps take suction from the spent fuel pool and recirculate the fluid back to the pool after passing through the coolers. A portion of the flow is demineralized and filtered depending on conditions. There are three pumps for Oconee Units 1 and 2, and three pumps for Oconee 3. The spent fuel coolant pumps are also used for filling the fuel transfer canal or incore instrumentation handling tank with borated water from the borated water storage tank.

Spent Fuel Coolant Demineralizers

One spent fuel coolant demineralizer will process approximately one-half of the spent fuel pool volume in 24 hours. There is one demineralizer for Units 1 and 2, and one for Unit 3.

Spent Fuel Coolant Filters

The spent fuel coolant filters are designed to remove particulate matter from the spent fuel pool water. They are sized for the same flow rate as the demineralizers (180 gpm). There are two filters for Units 1 and 2, and two for Unit 3.

Borated Water Recirculation Pump

This pump removes water from the borated water storage tank for demineralization and filtering. The
pump may also be used while demineralizing and filtering the water in the fuel transfer canal during a
7 transfer of fuel. It may also be used for emptying the fuel transfer canal if spent fuel coolant pumps are
unavailable for use. There is one pump for Units 1 and 2, and one for Unit 3.

9.1.3.3 System Evaluation

9.1.3.3.1 Normal Operation

7 The normal operation of the Spent Fuel Cooling System provides several functions. The most safety
7 significant of these functions is to maintain pool inventory so that stored fuel is always covered with
7 water. In order to protect against loss of inventory by boil-off, the system maintains the pool temperature

7 below the design bases limits specified in Section 9.1.3.1, "Design Bases." The system also maintains the
7 pool clarity and chemistry at acceptable levels.

2 Spent fuel pool heat removal is accomplished by recirculating spent fuel coolant water through heat
2 exchangers and then back to the pool. The spent fuel pumps take suction from the spent fuel pool and
2 transport the flow through the coolers, which are arranged in parallel. The waste heat is removed from
2 the shell side of the coolers by the Recirculated Cooling Water System. The cooled spent fuel pool water
2 is then directed back to the spent fuel pool.

2 The spent fuel pool water temperature is a direct function of the decay heat load produced by the fuel in
2 the racks, in conjunction with the heat removal capability of the spent fuel cooling system. The total heat
2 removal capacities are the same for the Units 1 and 2 and the Unit 3 spent fuel pool coolant systems.
2 Both systems use the same numbers of pumps and coolers, with the same design specifications and overall
2 equipment configurations. The expected decay heat loads vary with the number of fuel assemblies present
2 in the pool, the burnups of the various fuel assemblies, and the post-irradiation decay times.

2 At the time that the Units 1 and 2 spent fuel pool was re-racked, its spent fuel cooling system was
2 upgraded to handle the higher total heat load expected from the increased number of stored fuel
2 assemblies. The heat removal capability of the upgraded spent fuel cooling system has been sized to meet
2 the design limits specified in Section 9.1.3.1, "Design Bases." A specific analysis of expected maximum
2 normal and abnormal heat loads was performed, based on 18 month cycles, with average fuel burnups of
5 421 EFPDs. The Spent Fuel Cooling System was analyzed to predict the pool temperatures which would
5 result from these heat loads. Temperatures meet the design requirements as specified in Section 9.1.3.1,
5 "Design Bases."

2 At the time that the Unit 3 spent fuel pool was re-racked, its spent fuel cooling system was upgraded to
2 handle the higher total heat load expected from the increased number of stored fuel assemblies. The heat
2 removal capability of the upgraded spent fuel cooling system has been sized to meet the design limits
2 specified in Section 9.1.3.1, "Design Bases." A specific analysis of expected maximum normal and
2 abnormal heat loads was performed, based on 18 month cycles, with average fuel burnups of 440 EFPDs.
5 Again, the Spent Fuel Cooling System was analyzed to predict the pool temperatures resulting from these
5 heat loads. These temperatures meet the design requirements as specified in Section 9.1.3.1, "Design
2 Bases."

5 During an actual refueling outage for any unit at ONS, it is now common practice to offload a full core
5 (177 fuel assemblies) into the pool. The resulting heat load under this condition will be less than the
5 abnormal heat load cases evaluated in Sections 9.1.3.1.1, "Units 1 and 2 Spent Fuel Pool Cooling
5 System" and 9.1.3.1.2, "Unit 3 Spent Fuel Pool Cooling System" for the Units 1 and 2 fuel pool and
5 Unit 3 fuel pool respectively. In addition, the resulting temperature will be less than 205°F in the fuel
5 pools in the abnormal heat load case, assuming a single active failure. The seismic structural integrity of
5 the storage racks, pools, and supporting structures has been evaluated at or above this temperature, and
5 found to be adequate. Also, the thermal-hydraulic analysis of the storage racks indicates that localized
5 boiling will not occur if water entering the storage cells reaches this temperature, as long as normal pool
5 level is maintained.

2 A bypass purification loop is provided to maintain the purity of the water in the spent fuel pool. This
2 loop is also utilized to purify the water in the borated water storage tank following refueling, and to
2 maintain clarity in the fuel transfer canal during refueling. Water from the borated water storage tank or
2 fuel transfer canal can be purified by using the borated water recirculation pump.

9.1.3.3.2 Failure Analysis

An analysis of the maximum fuel cladding temperature has been performed for the postulated case of complete loss of coolant circulation to the pool. The analysis assumes maximum anticipated heat load in the pool, with the hottest assembly located in the least cooled storage area. The maximum cladding temperature will occur at the location of maximum heat flux. For a fuel assembly having the maximum value for decay heat power of 80 kw, and for an axial peak to average power density ratio of 1.2, the maximum local fuel rod heat flux is 1200 BTU/hr-ft^2. Natural circulation flow rates within the storage tubes have been calculated which give confidence that convection film coefficients in excess of 50 BTU/hr-ft^2 °F can be expected. Assuming this low value for conservatism, the clad surface temperature is 24°F above the coolant temperature. Because the heat flux is small, very large uncertainties in the film coefficient are acceptable without causing prohibitively high clad temperatures. For example, a reduction by a factor of five in the film coefficient would result in a clad surface temperature of 120°F above the coolant temperature. A reduction by a factor of ten, from 50 BTU/hr-ft^2 °F to 5 BTU/hr-ft^2 °F would result in a clad surface temperature of 240°F above the coolant temperature. These temperatures are below 650°F, which is the normal operating temperature of the fuel clad in the core.

9.1.3.4 Safety Evaluation

The Spent Fuel Cooling System provides adequate capacity and component redundancy to assure the cooling of stored spent fuel, even when large quantities of fuel are in storage. Multiple component failures or complete cooling failures permit ample time to assure that protective actions are taken. The system is
7 arranged so that loss of fuel pool water by piping or component failure is highly improbable. The system performs no emergency functions. Alarms are provided to alert operator of abnormal pool level and temperature.

7 The Spent Fuel Cooling System has one process line connecting to the Reactor Coolant System through
7 the SSF RC Makeup line. Its major penetration to the Reactor Building is through the fuel transfer tube. The fuel transfer tube is isolated inside the Reactor Building by a blind flange connection in the fuel transfer canal.

9.1.4 FUEL HANDLING SYSTEM

9.1.4.1 Design Bases

9.1.4.1.1 General System Function

9 The fuel handling system shown on Figure 9-7 (sheets 1 & 2) is designed to provide a safe, effective means of transporting and handling fuel from the time it reaches the station in an unirradiated condition until it leaves the station after postirradiation cooling. The system is designed to minimize the possibility of mishandling or maloperations that could cause fuel assembly damage and/or potential fission product release.

Separate fuel handling equipment is provided for each reactor. A common fuel storage area serves Oconee 1 and 2, while a separate fuel storage area is provided for Oconee 3.

7 The reactors are refueled with equipment designed to handle the spent fuel assemblies underwater from
7 the time they leave the reactor vessels until they are placed in a cask for shipment from the spent fuel
7 pools. Underwater transfer of spent fuel assemblies provides an effective, economic, and transparent radiation shield, as well as a reliable cooling medium for removal of decay heat. Use of borated water assures reactor subcriticality during refueling.

9.1.4.1.2 New Fuel Storage

New Fuel Storage is described in Section 9.1.1, "New Fuel Storage."

9.1.4.1.3 Spent Fuel Pool

Each spent fuel pool is a reinforced concrete pool located in its respective Auxiliary Building. The Oconee 1, 2 pool is lined with stainless clad plate. The Oconee 3 pool is lined with stainless steel plate.
8 The unit 1 and 2 spent fuel pool will hold 1312 fuel assemblies. The unit 3 spent fuel pool will hold 822
8 assemblies plus 3 spaces for failed fuel canisters. Fuel components (such as control rods, BP's, or
8 APSR's) requiring removal from the reactors are stored in the spent fuel assemblies or in brackets
8 suspended from the top of the fuel racks.

9.1.4.1.4 Fuel Transfer Tubes

Two horizontal tubes are provided to convey fuel between each Reactor Building and the respective Auxiliary Building. These tubes contain tracks for the fuel transfer carriages, gate valves on the spent fuel pool side, and a means for flanged closure on the Reactor Building side. The fuel transfer tubes penetrate the spent fuel pool and the fuel transfer canal at their lower depth, where space is provided for the rotation of the fuel transfer carriage baskets.

9.1.4.1.5 Fuel Transfer Canal

The fuel transfer canal is a passageway in the Reactor Building extending from the reactor vessel to the Reactor Building wall. It is formed by an upward extension of the primary shield walls. The enclosure is a reinforced concrete structure lined with stainless clad plate to form a canal above the reactor vessel which is filled with borated water for refueling.

Space is available in the deeper portion of the fuel transfer canal for underwater storage of the reactor vessel internals upper plenum assembly. This portion of the fuel transfer canal can also be used for storage of the reactor vessel internals core barrel and thermal shield assembly by storing the upper plenum assembly in the upper end of the fuel transfer canal.

9.1.4.1.6 Fuel Handling Equipment

9 This equipment consists of fuel handling bridges, fuel handling mechanisms, fuel storage racks, fuel transfer mechanisms, and shipping casks. In addition to the equipment directly associated with the handling of fuel, equipment is provided for handling the reactor vessel closure head and the upper plenum assembly to expose the core for refueling.

9.1.4.2 System Description and Evaluation

9.1.4.2.1 Receiving and Storing Fuel

New fuel assemblies are received in shipping containers, unloaded and stored in the appropriate spent fuel pool. After reactor shutdown, new fuel assemblies can be transferred from the spent fuel pool to the Reactor Building with the use of the fuel transfer mechanisms and the fuel transfer tubes.

9.1.4.2.2 Loading and Removing Fuel

Following the reactor shutdown and Reactor Building entry, the refueling procedure is begun by removal
7 of the reactor closure head. Prior to this it is necessary to uncouple the control rods from the drive
7 mechanisms. An auxiliary hoist (the CRDM crane, located over the fuel transfer canal) is used for this

7 and any other special purposes that may be required during refueling. The electrical and water
connections to the head assembly are disconnected.

7 To close the annular space between the reactor vessel flange and fuel transfer canal floor, a seal plate is
7 lowered into position and bolted to the canal shield flange with appropriate gaskets. The isolation valves
7 on the spent fuel pool end of the fuel transfer tubes are closed and the tubes drained. The blind flanges
7 on the reactor building end of the transfer tubes are then removed.

7 Head removal and replacement time is minimized by the use of multiple tensioners. The stud tensioners
7 are hydraulically operated to permit preloading and unloading of the reactor vessel closure studs at cold
7 shutdown conditions. The studs are tensioned to their operational load in discrete steps in a
7 predetermined sequence. Required stud elongation after tensioning is verified by an elongation gauge.

Following removal of the studs from the reactor vessel tapped holes, the studs and nuts are supported in
0 the closure head bolt holes with specially designed spacers. The studs and nuts are then removed from
0 the reactor closure head for inspection and cleaning using special stud and nut handling fixtures. Two
special alignment studs are installed in stud location Nos. 15 and 45. The lift of the head and replacement
after refueling is guided by these studs. These studs are also used to locate the index fixture used for
0 aligning the plenum assembly during removal and replacement. Storage racks are provided for the closure
0 head studs and the alignment studs.

The reactor closure head is lifted out of the canal onto a head storage stand on the operating floor by a
head and internals handling fixture attached to the polar crane. The stand is designed to protect the
7 gasket surface of the closure head.

7 The upper plenum assembly is removed from the reactor, using the head and internals handling fixture
7 and adaptors attached to the polar crane with an internals handling extension, and stored in the deeper
7 portion of the fuel transfer canal on a stand on the canal floor. The reactor vessel stud holes except for
7 locations Nos. 15 and 45 are closed with special plugs that prevent water and/or other foreign substances
7 from entering the holes. The fuel transfer canal is then filled with borated water.

7 The original plant design provided provisions for optimizing refueling operations by using two fuel
9 handling bridges in each Reactor Building, a Main Bridge and an Auxiliary Bridge, which spanned the fuel
9 transfer canal. The Main Bridge was used to shuttle spent fuel assemblies from the core to the transfer
9 station and new fuel assemblies from the transfer station to the core, while the Auxiliary Bridge was used
9 to relocate partially spent fuel assemblies within the core as specified by the fuel management program.
7 The full core off-load refueling practice is now normally used. Fuel shuffling is performed by completely
7 unloading the core using the Main Bridge, shuffling the control components in the spent fuel pool using
7 manual tools suspended from an overhead hoist mounted on the Spent Fuel Bridge, and then reloading
9 the core. Since the Auxiliary Bridges were no longer needed for their original design purpose (Main
9 Bridge could be used if 'in-core' shuffling *of fuel assemblies* became necessary) and they were an
9 interference for fuel handling activities, the Auxiliary Bridges were physically removed from the Reactor
9 Buildings (ref. NSM X2914).

9 In the original plant design, each unit's Main Bridge was equipped with two trolley-mounted hoists. One
9 hoist (fuel handling mechanism) was equipped with a fuel grapple and the second hoist (control rod
9 handling mechanism) housed the control rod grapple. (The Unit 3 Main Bridge was later upgraded to
9 one trolley mounted multiple purpose hoist equipped with both fuel and component grapples). The Main
9 Bridges now have one trolley mounted hoist equipped with a fuel grapple only. (ref. NSM-X2914) The
9 Auxiliary Bridges (which consisted of one trolley-mounted hoist with fuel grapple only) for each unit has
9 been removed. Each fuel handling bridge uses a pneumatic system for grapple operation. (ref. NSM
9 X2914)

The Main Bridge moves a spent fuel assembly from the core underwater to the transfer station where the
9 fuel assembly is lowered into the fuel transfer carriage fuel basket. The Main Bridges have a fuel mast
9 only and are not capable of handling components (ref. NSM-X2914). Components are shuffled in the
9 spent fuel pool (after complete core off load) using manual tools suspended from an overhead hoist
9 mounted on the Spent Fuel Bridge, and then reloaded the core

Spent fuel assemblies removed from the reactors are transported to the spent fuel pool from the Reactor Building via fuel transfer tubes by means of the fuel transfer mechanism. The fuel transfer mechanisms are carriages that run on tracks extending from each spent fuel pool through the transfer tubes and into the respective Reactor Building. Each of the two independently operated fuel transfer mechanisms which serve Oconee 1 and 2 is designed to operate in two directions so that either of the two Reactor Buildings can be serviced by one or two mechanisms as required. A rotating fuel basket is provided on each end of each fuel transfer carriage to receive fuel assemblies in a vertical position. The hydraulically operated fuel basket is rotated to a horizontal position for passage through the transfer tube, and then rotated back to a vertical position in the spent fuel pool or Reactor Building for vertical removal or insertion of the fuel assembly.

The spent fuel assemblies are removed from the fuel transfer carriage fuel basket using a fuel handling bridge equipped with a fuel handling mechanism and fuel grapple. This bridge spans the spent fuel pool and permits the refueling crew to store or remove new and spent fuel assemblies in any one of the storage rack positions. Spent fuel assemblies may be moved within the spent fuel pools by use of the fuel
5 handling bridge auxiliary hoist and appropriate remote handling tools. In addition, a Post Irradiation
5 Examination jib crane, with associated grapple that may be used to move fuel, is installed in the Unit 1
5 and 2 spent fuel pool.

Once refueling is completed, the fuel transfer canal is drained through a pipe located in the deep transfer station area. The canal water is pumped to the borated water storage tank to be available for the next refueling.

During operation of the reactors, the fuel transfer carriages are stored in the respective spent fuel pools, thus permitting a blind flange to be installed on the Reactor Building side of each tube.

Space is provided in each spent fuel pool to receive a spent fuel shipping cask as well as provide for required fuel storage. The layout of the fuel pool is shown on Figure 1-4 through Figure 1-8. The cask area is located at the north end of the fuel pools and adjacent to the fuel racks. Following a decay period, the spent fuel assemblies are removed from storage and loaded into the spent fuel shipping cask under water for removal from the site. The spent fuel shipping cask does not pass over fuel storage racks, or any systems or equipment important to safety when being moved to or from the spent fuel pool.

7 The spent fuel cask handling facility consists of a 100-ton capacity overhead bridge crane with a 13 foot 6
inch span. The hoist controls are five step magnetic, contactor reversing, secondary resistor type with time delay acceleration and a maximum speed of 9 feet per minute. The hoist is equipped with AC solenoid-operated brake system and an eddy-current brake. The bridge controls are the same as the hoist controls and are equipped with AC solenoid operated brake system and has a maximum speed of 50 feet per minute. The trolley is a single speed, four feet/minute, magnetic contactor reversing type controller with AC solenoid-operated brake system. The cranes were designed in accordance with Electric Overhead Crane Institute's Specification No. 61, Class A.

The cranes were tested in the shop by performing a running test, and load tested at the Oconee site to 98 percent of capacity. The running and load test results were satisfactory. Maintenance of the cranes is in accordance with ANSI B30.2. The structural and mechanical components of the crane are designed to have a minimum factor of safety of 2.5 based on yield strength and rated capacity. The hoist brake system consists of the dynamic AB 707 eddy-current control brake and a 13-inch solenoid-operated shoe brake (Whiting SESA). The bridge is equipped with a hydraulic brake for operating the crane from the cab and a solenoid-operated shoe brake for operating the crane by pendant control from the floor. The trolley is equipped with a solenoid-operated shoe brake. The hoist system is equipped with a 75 horsepower motor that produces 328 foot-pounds of torque at full load, 1200 rpm. The starting and instantaneous stalling torque is 902 foot-pounds. The hoist is equipped with a geared lower limit switch for block travel and a paddle-type upper limit switch to prevent a two-blocking situation from occurring.

The cranes are equipped with a sister type hook with safety latch. The hook was load tested and non-destructive tested in the shop. Bethanized wire rope with a safety factor of 6 was used. A lifting adapter to be used between the yoke and the crane hook is also designed to support three times the load. The lifting adapter is a stainless steel member approximately 24 feet long, used to lift the cask from the platform to the bottom of the spent fuel pool.

A decontamination area is located in the building adjacent to each spent fuel pool where the outside surfaces of the casks can be decontaminated prior to shipment by using water, detergent solutions and manual scrubbing to the extent required.

9.1.4.2.3 Safety Provisions

Safety provisions are designed into the fuel handling system to prevent the development of hazardous conditions in the event of component malfunctions, accidental damage or operational and administrative failures during refueling or transfer operations.

All fuel assembly storage facilities employ neutron poison material and/or maintain an eversafe geometric spacing between assemblies to assure fuel storage arrays remain subcritical under all credible storage conditions. The fuel storage racks are designed so that it is impossible to insert fuel assemblies in other than the prescribed locations, thereby assuring the necessary spacing between assemblies. Fuel handling and transfer containers are also designed to maintain an eversafe geometric array. Under these conditions, a criticality accident during refueling or storage is not considered credible.

Fuel handling equipment is designed to minimize the possibility of mechanical damage to the fuel assemblies during transfer operations. If fuel damage should occur, the amount of radioactivity reaching the environment will present no hazard. The fuel handling accident is analyzed in Chapter 15, "Accident Analyses."

5 All spent fuel assembly transfer operations are conducted underwater. The water level in the fuel transfer
5 canal provides a nominal water level of 9 feet over the active fuel line of the spent fuel assemblies during
5 movement from the core into storage to limit radiation at the surface of the water. The fuel storage racks
5 provide a nominal 23.5 feet of water shielding over the stored assemblies. The minimum water depth over
5 the stored fuel assemblies is equal to, or greater than 21.34 feet. The minimum depth of water over the
5 fuel assemblies and the thickness of the concrete walls of the storage pool are sufficient to limit radiation
5 levels in the working area. Dose rate information for fuel transfer conditions, and from the storage racks
5 in the Spent Fuel Pool, are provided in Section 12.3.1, "Facility Design Features."

Water in the reactor vessel is cooled during shutdown and refueling as described in Section 9.3.3, "Low Pressure Injection System." Adequate redundant electrical power supply assures continuity of heat removal. The spent fuel pool water is cooled as described in Section 9.1.3, "Spent Fuel Cooling System." A power failure during the refueling cycle will create no immediate hazardous condition due to the large water volume in both the transfer canal and spent fuel pool. With a normal quantity of spent fuel assemblies in the storage pool and no cooling available, the water temperature in the spent fuel pool would increase very slowly (Section 9.1.3, "Spent Fuel Cooling System").

7 During reactor operations, bolted and gasketed closure plates, located on the reactor building flanges of
7 the fuel transfer tubes, isolate the fuel transfer canal from the spent fuel pool. Both the spent fuel pool and the fuel transfer canals are completely lined with stainless clad steel plate for leak tightness and for ease of decontamination. The fuel transfer tubes will be appropriately attached to these liners to maintain leak integrity. The spent fuel pool cannot be accidentally drained by gravity since water must be pumped out.

During the refueling period the water level in both the fuel transfer canal and the spent fuel pool is the same, and the fuel transfer tube valves are open. This eliminates the necessity for interlocks between the fuel transfer carriages and transfer tube valve operations except to verify full-open valve position.

7 The fuel transfer canal and spent fuel pool water will have a boron concentration as specified by the Core
7 Operating Limits Report. Although this concentration is sufficient to maintain core shutdown if all of the control rod assemblies were removed from the core, only a few control rods will be removed at any one time during the fuel shuffling and replacement. Although not required for safe storage of spent fuel assemblies, the spent fuel pool water will also be borated so that the transfer canal water will not be diluted during fuel transfer operations.

The fuel transfer mechanisms permit initiation of the fuel basket rotation from the building in which the fuel basket is being loaded or unloaded. Carriage travel and fuel basket rotation are interlocked to prevent
7 inadvertent carriage movement when the fuel basket is in the vertical position. Rotation of the fuel baskets is possible only when the carriages are in the rotating frame at the end of travel.

8 Interlocks are provided to prevent operation of the bridges or trolleys with a fuel assembly until the assemblies have been hoisted to the upper limit in the mast tube. Mandatory slow zones are provided for the hoisting mechanisms as the grapples approach the core and fuel baskets during insertion of fuel assemblies. The slow zones will be in effect during entry into the reactor core or fuel storage rack and just before and during bottoming out of the fuel assemblies. The controls are appropriately interlocked to prevent simultaneous movement of the bridge, trolley or hoists. The grapple mechanisms are interlocked with the hoists to prevent vertical movement unless the grapples are either fully opened or fully closed. The fuel grapple is so designed that when loaded with the fuel assembly, the fuel grapple cannot be
9 opened as a result of operator error, electrical, or pneumatic failure.

All operating mechanisms of the system are located in the fuel handling and storage area for ease of maintenance and accessibility for inspection prior to start of refueling operations. All electrical equipment, with the exception of some limit switches, is located above water for greater integrity and ease of maintenance. The hydraulic systems which actuate the fuel basket rotating frame use demineralized water for operation.

7 Fuel with suspected defective fuel rods are typically examined and tested for leakage. Leakage verification
7 utilizes an ultrasonic test rig which can be used to detect the presence of water inside a fuel pin. If this
7 method indicates that a fuel pin is defective then the fuel assembly will either be repaired or evaluated for
7 acceptability for use in future cycle designs.

9 The Main fuel handling bridges have a fuel mast only and are not capable of handling components. The
9 original design of the Main fuel bridges included separate hoists, which allowed control components to be
9 exchanged between fuel assemblies within the Reactor building. This capability has been removed. (ref
9 NSM-X2914) All lifts for handling of reactor closure heads and reactor internal assemblies will be made
9 using the Reactor Building Polar crane.

Travel speeds for the fuel handling bridges, hoists and fuel transfer carriages will be controlled to assure safe handling conditions.

4 Since 1990, Oconee has been involved in transferring spent fuel from the Unit 1 and 2 and the Unit 3
4 Spent Fuel Pools to an on-site Independent Spent Fuel Storage Installation. A specially designed transfer
4 cask and associated handling equipment is used for this operation. Cask handling accidents are addressed
5 in Chapter 15, "Accident Analyses." More detailed information on cask loading and handling activities
7 can be found in the ONS Site Specific and General License System ISFSI UFSARs.

9.1.5 REFERENCES

8 1. Calculation OSC-1870, "Oconee Nuclear Station Unit 3 Poison Spent Fuel Storage Racks"

8 2. Calculation OSC-6574, "Oconee Nuclear Station Unit 1 and 2 Poison Spent Fuel Storage Racks"

9 3. Calculation OSC-1875, "Slashing Effect of Water in Spent Fuel Pools"

5 4. Studsvik, "CASMO-3 A Fuel Assembly Burnup Program," STUDSVIK/NFA-89/3, Revision 4.4,
5 January, 1991.

5 5. Studsvik, "TABLES-3 Library Preparation Code for SIMULATE-3", STUDSVIK/SOA-92/03,
5 Revision 0, April, 1992.

5 6. Studsvik, "SIMULATE-3 Advanced Three-Dimensional Two-Group Reactor Analysis Code",
5 STUDSVIK/SOA-92/01, Revision 0, April, 1992.

5 7. M.N. Baldwin, et. al., "Critical Experiments Supporting Close Proximity Water Storage of Power
5 Reactor Fuel", The Babcock and Wilcox Company, BAW-1484-7, July, 1979.

5 8. Duke Power Company, Letter to U.S. Nuclear Regulatory Commission Document Control Desk,
5 from J.W. Hampton, November 22,1994, "Oconee Nuclear Station Docket Nos. 50-269,-270,-287
5 Unit 3 Cycle 16 Reload Technical Specifications".

5 9. U.S. Nuclear Regulatory Commission letter to All Power Reactor Licensees, from B.K. Grimes, April
5 14, 1978, "OT Position for Review and Acceptance of Spent Fuel Storage and Handling
5 Applications".

5 10. Oak Ridge National Laboratory, "SCALE 4.2, A Modular Code System for Performing Standardized
5 Computer Analyses for Licensing Evaluation", Volumes I-IV, NUREG/CR-200, Revision 4, April
5 1995.

5 11. Letter from W. O. Parker, Jr. (DPC) to H. R. Denton (USNRC), dated July 1, 1980.

5 12. Letter from W. O. Parker, Jr. (DPC) to H. R. Denton (USNRC), dated July 25, 1980.

5 13. USNRC Technical Branch Position ASB 9-2, "Residual Decay Energy for Light Water Reactors for
5 Long Term Cooling".

5 14. Letter from H. B. Tucker (DPC) to H. R. Denton (USNRC), dated March 10, 1983.

5 15. NUREG-0800, Standard Review Plan Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System".

7 16. Safety Evaluation by the Office of Nuclear Reactor Regulation related to Amendment No. 209 to
7 Facility Operating License DPR-38, Amendment No. 209 to Facility Operating License DPR-47,
7 Amendment No. 206 to Facility Operating License DPR-55, Duke Power Company, Oconee Nuclear
7 Station, Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

7 17. Letter from J. W. Hampton to USNRC, dated November 22, 1994, Oconee Nuclear Station Docket
7 Nos. 50-269, -270, -287 Unit 3 Cycle 16 Reload Technical Specifications, May 3, 1995.

8 18. License amendment 123, 123, and 120 for Units 1, 2 and 3 respectively.

8 19. License amendment 90, 90, and 87 for Units 1, 2 and 3 respectively.

8 20. Calculations OSC-1870, Rev D3, "Oconee Nuclear Station Unit 3 Poison Spent Fuel Storage Racks".

8 21. Calculations OSC-6574, Rev 0, "Oconee Nuclear Station Unit 1 and 2 Poison Spent Fuel Storage
8 Racks".

9 22. Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3, submitted
9 by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos.
9 50-269, -270, and -287.

9 23. NUREG-1723, Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station,
9 Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

9.2 WATER SYSTEMS

2

9.2.1 COMPONENT COOLING SYSTEM

9.2.1.1 Design Bases

The Component Cooling System is designed to provide cooling water for various components in the Reactor Building as follows: letdown coolers, reactor coolant pump cooling jacket and seal coolers, quench tank cooler, and control rod drive cooling coils. The design cooling requirement for the system is based on the maximum heat loads from these sources. The system also provides an additional barrier between high pressure reactor coolant and service water to prevent an inadvertent release of activity.

9.2.1.2 System Description and Evaluation

The Component Cooling System is shown schematically on Figure 9-8, and the performance requirements of the system are tabulated in Table 9-3. The following is a brief functional description of the major components of the system and their sharing between nuclear units of the station:

<u>Component Cooler</u>

Each component cooler is designed for the total Component Cooling System heat load for a reactor unit. Oconee 1 and 2 each have a single component cooler with a shared common spare. Oconee 3 has two coolers. The coolers reject the heat load to the Low Pressure Service Water System.

<u>Component Cooling Pumps</u>

Each component cooling pump is designed to deliver the necessary flows to the letdown coolers, reactor coolant pump cooling jackets and seal coolers, quench tank cooler, and control rod drive cooling coils. Each unit has one operating pump and one spare.

<u>Component Cooling Surge Tank</u>

This tank allows for thermal expansion and contraction of the water in this closed-loop system. It also provides the required NPSH for the component cooling pumps.

<u>Control Rod Drive Filters</u>

Two filters are provided in the cooling water circuit to the control rod drives to prevent particulates from entering the drive cooling coils. Only one filter is used at a time, with the second as a spare. A bypass is also provided.

9.2.1.3 Mode of Operation

During operation, one component cooling pump and one component cooler recirculate and cool water to accommodate the system heat loads for each reactor unit. The component cooling surge tank accommodates expansion, contraction, and leakage of coolant into or out of the system. The surge tank provides a reservoir of component cooling water until a leaking cooling line can be isolated. Makeup water and corrosion inhibiting chemicals are added to the system in the surge tank.

9.2.1.4 Reliability Considerations

The Component Cooling System performs no emergency functions. Redundancy in active components is provided to improve system reliability. The pumps, coolers, surge tank, and most of the instrumentation are located in the Auxiliary Building and are accessible for inspection and maintenance.

9.2.1.5 Codes and Standards

2 The components of the system are designed to the codes and standards given in Table 9-13.

9.2.1.6 System Isolation

Since the Component Cooling System is not an engineered safeguards system, Reactor Building isolation valves are automatically closed on a high Reactor Building pressure signal to provide building isolation. The Reactor Building inlet lines are isolated by two check valves, one on the outside and one on the inside of the Reactor Building. The Reactor Building outlet line is isolated by an electric motor-operated valve on the inside and by a pneumatic valve on the outside of the Reactor Building.

9.2.1.7 Leakage Considerations

Water leakage from piping, valves, and other equipment in the system is not considered to be detrimental since the cooling water is normally nonradioactive. Welded construction is used throughout the system to minimize the possibility of leakage except where flanged connections are required for servicing.

8 In-leakage of reactor coolant to the system is detected by a radiation monitor (RIA-50) located in the
8 pump recirculation line and is also indicated by an increase in surge tank level. A defective coil of a coolant pump can be remotely isolated by an electric motor-operated valve on the outlet cooling line and a stop-check valve on the inlet line. A letdown cooler leak can be remotely isolated with motor-operated valves on the reactor coolant side of the cooler. The cooling water side can be completely isolated by closing a remotely operated, motor-actuated valve on the inlet of the cooler and the manual valves on the outlet cooling lines. Leakage from the quench tank cooler can be isolated by manual valves on the reactor coolant side. The cooling water side can be completely isolated by two manual valves.

9.2.1.8 Failure Considerations

Since the system serves no engineered safeguards function, the only consideration following a loss-of-coolant accident is the operation of the isolation valves. Redundant isolation valves are provided as described in Chapter 6, "Engineered Safeguards." Failures and malfunction of components during normal operation were evaluated. Operation of the Component Cooling System is essential to normal reactor operation. In the event of loss of a component cooling pump, the standby pump will automatically start and maintain cooling water flow. The complete loss of cooling water flow does not require immediate reactor shutdown. However, procedures will require the operator to shutdown the reactor to protect the control rod drive coils. The reactor coolant pumps can be operated without component cooling water if seal injection flow is available.

9.2.2 COOLING WATER SYSTEMS

9.2.2.1 Design Bases

The cooling water systems for the station are designed to provide redundant cooling water supplies to insure continuous heat removal capability both during normal and accident conditions.

4 The Low Pressure Service Water (LPSW) and portions of the Condenser Circulating Water (CCW)
6 systems are designed so no single component failure will impair emergency safeguards operation.
Redundant pumping capability is provided, heat exchangers and pumps can be isolated and pressure reducing valves are provided with bypasses.

All cooling systems are designed to be operated and monitored from the control room. Component design parameters are given in Table 9-4.

The design purpose of each of the cooling water systems is outlined below:

Condenser Circulating Water (CCW) System - This system provides for cooling of the condensers
2 during normal operation of the plant. The system also serves as the ultimate heat sink for decay heat
4 removal during cooldown of the plant. The CCW System is the suction source for other service water
4 systems, including HPSW, LPSW, ASW, and SSF ASW. In addition, CCW provides a heat sink for
4 the RCW system. Following a design basis event involving loss of the CCW pumps, the Emergency
2 Condenser Circulating Water (ECCW) System supplies suction to the LPSW pumps.

High Pressure Service Water (HPSW) System - This system provides a source of water for fire protection throughout the station. In the event of a loss of the normal LPSW supply, HPSW automatically supplies cooling water to the HPI pump motor coolers. For loss of A.C. power, HPSW via the Elevated Water Storage Tank automatically supplies cooling water to the Turbine
9 Driven Emergency Feedwater Pump and its associated Oil Cooler.

Low Pressure Service Water (LPSW) System - This system provide cooling water for normal and emergency services throughout the station. Safety related functions served by this system are:

1. Reactor Building cooling units.
2. Decay heat removal coolers.
3. High pressure injection pump motor bearing coolers.
0 4. Motor-Driven Emergency Feedwater Pump motor air coolers.
5. Turbine Driven Emergency Feedwater Pump cooling water jacket
9 6. Siphon Seal Water

6 Recirculated Cooling Water (RCW) System - This is a closed loop system to supply corrosion inhibited cooling water to various components. This system has no direct safety related functions.

9

8 Essential Siphon Vacuum (ESV) System - This system supports the Condenser Circulating Water
8 (CCW) system by removing air from the CCW Intake header during normal and siphon modes of
8 operation. The nuclear safety-related functions are:

8 1. Remove air from the CCW Intake Headers during normal operation to ensure that the operable
8 Intake Headers are primed at the start of an event requiring the siphon mode of operation.

8 2. Remove air from the CCW Intake Headers during the siphon mode of operation to ensure that
8 the siphon does not fail due to air accumulation during a Design Basis Accident involving loss of
8 power to the CCW pumps.

8 The ESV system is installed on Units 2 and 3 only.

8 Siphon Seal Water (SSW) System - This system's nuclear safety-related function is to support the
8 ESV system by providing operating liquid to the ESV pumps. The ESV pumps are liquid ring
8 vacuum pumps which require a continuous supply of water in order to create a vacuum. Additionally,
8 it has a non-nuclear safety-related function of providing sealing and cooling water to the CCW pumps
8 and motors.

8 On July 18, 1989 the NRC Issued Generic Letter 89-13, "Service Water System Problems Affecting
8 Safety-Related Equipment," requesting holders of operating licenses to supply information about their
8 respective service water systems to assure the NRC of compliance with the recommended actions of
8 Generic Letter 89-13, and to confirm that the safety functions of their respective service water systems are
8 being met. Oconee's responses to Generic Letter 89-13 are contained in references 7, 8, 9, 10, 12. In
8 order to assure the adequacy of the Oconee service water systems and safety related heat exchangers to
8 perform their functions as designed, a Service Water System Program has been established in accordance
8 with NSD-312. The Service Water System Program consists of all those activities related to the service
8 water systems and components, including periodic inspections, repairs, replacements, monitoring and
8 testing.

9.2.2.2 System Description and Evaluation

9.2.2.2.1 Condenser Circulating Water System (CCW)

7 The Little River arm of Lake Keowee is the source of water for the CCW systems. Figure 2-4 shows the arrangement of the systems with respect to the two branches of Lake Keowee. Each unit has four condenser circulating water pumps supplying water via two 11 ft. conduits into a common condenser intake header under the turbine building floor. The discharge from the condenser is returned to the Keowee River arm of Lake Keowee.

5 The suction of the condenser circulating water pumps extends below the maximum drawdown of the lake. The intake structure is provided with screens which can be manually removed for periodic cleaning.

5 The CCW system is designed to take advantage of the siphon effect so the pumps are required only to
5 overcome pipe and condenser friction loss.

2 The CCW system has an emergency discharge line to the Keowee hydro tailrace. This discharge line is connected to each of the three condensers of each unit. Under a loss-of-power situation, the emergency discharge line will automatically open and the CCW system will continue to operate as an unassisted siphon system supplying sufficient water to the condenser for decay heat removal and emergency cooling
2 requirements. This siphon system is the Emergency Condenser Circulating Water (ECCW) System and
3 can be divided into two distinct parts. The "first siphon" takes suction from the CCW intake canal and
3 supplies flow to the CCW crossover header in the Turbine Building basement, where the LPSW System
3 takes its suction. The "second siphon" takes suction from the condenser inlet piping, supplies flow
3 through the condenser, and discharges to the Keowee Hydro tailrace. A loss of function of the second
3 siphon would not affect the capability of the first siphon to perform its function.

3 In a loss of off-site power (LOOP) situation, the CCW pumps will be tripped by a load shed command.
8 The ECCW System first siphon is required to supply suction to the LPSW System until a CCW pump
3 can be manually restarted by the control room operator. Gravity flow (without relying on the siphon) to

3 the suction of the LPSW pumps is possible if the lake level is sufficiently above the bottom of the CCW
3 intake piping to maintain the required NPSH and flow demand. Refer to Section 16.9.7, Selected
4 Licensee Commitments Manual, for additional requirements regarding the CCW Supply to the LPSW
4 System.

3 During a loss of all AC power situation (Station Blackout), the CCW System is not required to supply
3 suction to the LPSW System since power to the LPSW pumps would not be available. The second
7 siphon is not required. Decay heat removal can be accomplished by venting steam to the atmosphere
3 using the main steam safety valves or the manual atmospheric dump valves. The CCW piping has
4 sufficient inventory to cope with a four-hour Station Blackout by supplying suction to the SSF Auxiliary
4 Service Water System. (Reference 8.3.2.2.4, "Station Blackout Analysis.")

3

3 During normal operation, the continuous vacuum priming system removes noncondensible gases from
5 portions of the CCW System. An emergency steam air ejector (ESAE) is available to enhance operation
5 of the second siphon if the vacuum priming pumps are lost due to a loss of power. The essential siphon
8 vacuum (ESV) system is connected to the CCW inlet header to remove non-condensible gases during
8 normal and siphon operations.

4 Pursuant to the recommendations of the Oconee Probabilistic Risk Assessment study a pushbutton has been installed in the control room for sending a close signal to the CCW pump discharge valves. The capability to close the CCW valves is needed to protect against the possibility of CCW siphoning into the turbine building basement, causing flooding.

5 The intake canal that supplies water from Lake Keowee to the suction of the CCW pumps contains a
5 submerged weir. The purpose of this weir is to provide an emergency pond of cooling water if the water
5 supply from Lake Keowee were lost. This emergency pond could be recirculated through the condensers
5 and back to the intake canal for decay heat removal as long as the intake canal level remains sufficient.
5 However, during the operating license review of Oconee Units 2 and 3, the Atomic Energy Commission
5 (AEC) staff requested a reanalysis of the capability of the weir to withstand hydraulic forces using more
5 conservative assumptions than those used in the original design. Based on results obtained, the AEC staff
5 concluded that a rapid drawdown of Lake Keowee could cause considerable displacement of the riprap
5 used to face the weir. However, the AEC staff did not require Duke Power to redesign the weir, since the
5 water trapped in the condenser intake and discharge piping below elevation 791 ft. MSL is adequate to
5 supply the three Oconee units with steam generator boil off for safe shutdown for a period of 37 days
5 (Reference 1). The Auxiliary Service Water (ASW) System is capable of using the inventory trapped in
5 the CCW piping for decay heat removal (Reference 9.2.3, "Auxiliary Service Water System"). Therefore,
5 the licensing basis does not rely on the weir nor recirculation of the intake canal for decay heat removal
5 after a loss of Lake Keowee event (Reference 2).

9.2.2.2.2 High Pressure Service Water System (HPSW)

The schematic arrangement of the HPSW system is shown on Figure 9-10. This system is used primarily for fire protection throughout the Oconee station. In the event of a loss of the normal LPSW supply, HPSW automatically supplies cooling water to the HPI pump motor coolers. For loss of AC power, HPSW via the elevated water storage tank automatically supplies cooling water to the turbine driven
8 emergency feedwater pump and its associated oil cooler. HPSW is also used as a backup supply to the
8 SSW system. Refer to Sections 16.9.7 and 16.9.8 for specific requirements to support the LPSW System.

Two full size (6000 gal/min at 117 psig) and one reduced size (500 gal/min at 117 psig) high pressure service water pumps supply the high pressure system. A 100,000 gallon elevated water storage tank provides inventory for a backup supply of water.

The 500 gal/min pump will normally operate to keep pressure on the fire headers. In the event of a fire, one full size pump provides adequate capacity for automatically maintaining the elevated water storage tank inventory. The second full size pump is an installed spare. The HPSW pumps take suction from the CCW system. The HPSW and LPSW pump suctions are connected to the 42 inch cross-connection
7 between the Condenser Circulating Water inlet headers for the three units. Manual isolation valves are provided so that service water may be supplied from any or all of the inlet headers.

4

9.2.2.2.3 Low Pressure Service Water System (LPSW)

The schematic arrangement of the LPSW system is shown on Figure 9-11 and Figure 9-12. Oconee 1 and 2 share three 15,000 gal/min LPSW pumps. The LPSW pumps and the HPSW pumps take suction from the 42 inch crossover line between the condenser inlet headers; two LPSW pumps are supplied by one suction line and the other pump is supplied by the other suction line. The HPSW system is
9 connected to LPSW at the LPSW pump discharge, but the interconnections are not used. The alignment
6 of HPSW to LPSW is not credited to mitigate any design basis accident or design event.

2 Suction is provided to the LPSW pumps via gravity flow or siphon flow from the CCW System (ECCW
2 mode) following a design basis accident where the CCW pumps are not running. Lake level is
2 administratively controlled to maintain sufficient NPSH for the LPSW pumps under these conditions.

8 The LPSW pumps have a minimum continuous flow rate of 4250 gpm based on manufacturer's
8 recommendation. On Oconee Units 1 & 2, two LPSW pumps are normally operating with the third
8 pump in standby. Therefore, on Oconee Units 1 & 2, the potential for interaction between running
8 LPSW pumps is possible whenever the total demand from system loads is minimized. The potential exists
8 where the stronger pump may close the weaker pump's discharge valve and keep it closed. The weaker
8 pump would then be exposed to extended dead-head conditions. To minimized the potential for
8 deadheading, procedural guidance has been provided to ensure LPSW flow will be maintained greater than
8 4,000 gpm on the shutdown unit whenever either Unit 1 or Unit 2 is shutdown in refueling. If this flow
8 rate cannot be maintained on the shutdown unit, the LPSW system must be reduced to one pump
8 operation. (References 3, 4)

8 On an engineered safeguards signal, the standby LPSW pump(s) starts resulting in three Unit 1 & 2
8 LPSW pumps operating or two Unit 3 LPSW pumps operating. Under this condition the potential exists
8 for the LPSW pumps to be operated below the recommended minimum continuous flow rate of 4250
8 gpm per pump, or for a stronger pump to deadhead a weaker pump during low flow conditions. To
8 avoid pump damage due to low flow conditions, a minimum flow line is provided for each LPSW pump.
8 (Reference 5)

0 The LPSW system provides cooling for components in the Turbine Building, the Auxiliary Building, and
0 in the Reactor Building. Two separate 24 inch lines provide LPSW to the components in the Auxiliary and Reactor Buildings. These two supply lines are further divided into four separate supply headers, two supplying the components in Oconee 1 and two supplying the components in Oconee 2. The decay heat removal coolers and the Reactor Building cooling units are supplied by separate LPSW supply lines. The return lines from the decay heat removal coolers and the Reactor Building coolers maintain separation to a point beyond a remote-operated isolation valve.

For Oconee 3, each of the two 15,000 gal/min LPSW pumps take their suction from the CCW crossover. These pumps provide cooling water via separate supply lines to engineered safeguards equipment in the Reactor Building and the Auxiliary Building similar to Oconee 1 and 2. The return lines from the Oconee
1 3 engineered safeguards maintain separation to a point beyond a remote-operated isolation valve.

The Turbine Building requirements for LPSW are supplied from other separate headers. The three pumps associated with Oconee 1 and 2 have a Turbine Building header serving the Turbine Building requirements for Oconee 1 and 2. The two pumps associated with Oconee 3 also have a Turbine Building header to supply the Oconee 3 requirements.

The separate flow paths serving the emergency safeguards equipment can be isolated by remote-operated isolation valves.

The LPSW system is monitored and operated from the control room. Isolation valves are incorporated in all LPSW lines penetrating the Reactor Building.

The three (per unit) Reactor Building coolers ("A," "B," and "C") are supplied by individual lines from the separate LPSW supply headers. Each inlet line is provided with a motor operated shutoff valve located outside the Reactor Building. Similarly, each discharge line from the coolers is provided with a motor operated valve located outside the Reactor Building. This allows each cooler to be isolated
6 individually. During normal operation, the "A" and "C" coolers can receive throttled flow while flow
6 through the "B" cooler may be diverted to the four Reactor Building auxiliary cooling units to provide
normal Reactor Building cooling. Flow to the RB auxiliary cooling units is automatically isolated by an
6 engineered safeguards signal returning full flow to the "B" RB cooling unit. LPSW is simultaneously
8 aligned to the "B" RBCU and the auxiliary coolers (reference 13). This alignment ensures sufficient flow
8 is maintained through a RBCU to prevent condensation induced waterhammers which are not bounded
8 by existing analysis. This alignment also allows LPSW to supply the auxiliary cooling units for reactor
8 building temperature control. On an engineered safeguards signal the outlet valves on the three RB
cooling units fully open automatically to assure emergency flow through coolers.

2 The LPSW System provides sufficient flow to the Low Pressure Injection (LPI) coolers and Reactor
2 Building Cooling Units (RBCUs) to ensure sufficient heat transfer capability following a design basis
2 accident and a single active failure. The worst case design basis accident involves a LOCA/loss of offsite
3 power with a loss of instrument air. The worst case single failures for achieving desired flows to the
2 RBCUs and LPI coolers are 1) failure of a single LPSW pump, and 2) failure of a 4160 volt bus which
2 fails an LPSW pump, an RBCU fan, and an LPI cooler isolation valve. Analysis and testing have been
2 performed to demonstrate system performance under worst case conditions.

2 The LPSW System can provide sufficient flow to the required loads following a seismic event. Valves
7 1LPSW-139, 2LPSW-139, and 3LPSW-139 are remotely-operated, seismically-qualified valves which can
2 isolate the non-seismic, non-essential header from the safety-related portions of the system. Other
2 non-seismic connections to the system exist which cannot be remotely isolated. Analyses have
2 demonstrated that, given a simultaneous failure of all non-seismic connections that cannot be remotely
2 isolated, the LPSW System can provide sufficient flow to the required loads.

8 LPSW flow to the LPI coolers is normally throttled using air-operated valves LPSW-251 and LPSW-252.
2 During a design basis accident involving a loss of instrument air, these valves fail open to their travel
2 stops. Motor-operated valves LPSW-4 and LPSW-5 will be used to throttle LPSW flow to the LPI
8 coolers under these conditions. Travel stops are in place on LPSW-251 and LPSW-252 to ensure LPSW
4 flow through an LPI cooler does not exceed the design limit of 7500 gpm under worst case conditions.

2 The LPSW flow to and from each Reactor Building cooler is measured. Provisions are available to
2 indicate cooler leakage.

9 LPSW is a non-radioactive cooling water system that is monitored for radioactivity. Monitoring is
9 required per Section 11.5.1, "Design Bases and Evaluation" since LPSW provides cooling to normally
9 radioactive systems. Components from these normally radioactive systems could potentially leak

9 radioactivity into LPSW. Upon any indication of radioactivity, the component suspected of leaking may
9 be individually isolated.

The LPSW pumps are connected to the 4160 volt buses which supply power to engineered safeguards equipment. The emergency power supply is adequate to operate all LPSW pumps upon a loss of off-site power.

During normal operation, the cooling requirements are supplied by operating one LPSW pump per unit.
1 The LPSW requirement following a loss of coolant accident can also be supplied by one pump per unit.
The spare pump is started by the engineered safeguards actuation signal to provide redundancy for single failure criteria.

8 LPSW supplies water to the SSW system.

9.2.2.2.4 Recirculated Cooling Water System (RCW)

The RCW system for the Oconee station is shown schematically in Figure 9-13. This system provides inhibited closed cycle cooling water to various components outside the Reactor Building including:

1. RC pump seal return coolers
2. Spent fuel cooling
3. Sample coolers
4. Evaporator systems
5. Various pumps and coolers in the Turbine Building

The RCW system consists of two parallel loops which are normally isolated from each other. One loop supplies cooling for shared station loads, Unit 1 and 2 loads and secondary loads on Unit 3. It consists of four motor-driven pumps and four RCW heat exchangers. A 25,000 gallon surge tank provides a surge volume to accommodate temperature changes and leakage. Condenser circulating water is used to cool the RCW heat exchangers. The other loop supplies cooling for Unit 3 primary loads. It consists of two motor-driven pumps and two RCW heat exchangers. It contains a 7,700 gallon surge tank and also utilizes condenser circulating water to cool the RCW heat exchangers. RCW effluent from the Auxiliary Building is monitored for radioactivity. Leakage of radioactive fluids from any of the coolers in the Auxiliary Building will be indicated by these monitors. Separate monitors are provided on the return lines from the Oconee 1 and 2 Auxiliary Building and the Oconee 3 Auxiliary Building.

The number of RCW pumps and RCW heat exchangers in operation varies depending on the spent fuel heat load and lake water temperature. The isolation valves, which normally separate the two parallel loops, can be opened, however; it is not a necessary configuration.

The RCW provides no engineered safeguards functions and does not penetrate the Reactor Building.

8 **9.2.2.2.5 Essential Siphon Vacuum and Siphon Seal Water Systems**

8 The Essential Siphon Vacuum (ESV) and the Siphon Seal Water (SSW) systems are discussed together
8 due to their inherit relatedness. Simplified schematic diagrams of the systems are shown in Figure 9-42
8 and Figure 9-43.

8 The ESV system consists of three (3) liquid ring vacuum pumps per unit. These pumps, one of which is
8 an installed spare, are connected to two (2) tanks. These tanks are connected to the CCW Intake headers
8 (one tank per header). A float valve is used to minimize CCW water passage into the ESV system. A

8 minimum flow line for the ESV pumps is provided on the tanks to ensure that a minimum amount of air
8 is passing through the ESV pumps. Without this minimum amount of air, the vacuum created in the
8 ESV pumps will cause cavitation, which, over a long period of time, can cause pump degradation. Short
8 periods of time (e.g., over a month) without minimum flow operation will not degrade the pumps.

8 During normal operations, an ESV pump and tank are aligned to a given CCW Intake header. Air
8 accumulation in the CCW Intake Header is removed by the ESV system in order to maintain the CCW
8 Intake Header primed during normal operations. During emergency operations, the ESV pump minimum
8 flow line is isolated and the ESV pumps remove any air accumulation that occurs in the CCW Intake
8 Header. This allows full ESV pump capacity to be directed toward the siphon until the event is mitigated.

8 The ESV pumps are controlled from the Control Room. Vacuum Tank pressure indication and pump
8 operating status are located in the control room. Float valve heat trace current and valve temperature
8 indications are also available in order to allow monitoring of float valve condition during sub-freezing
8 weather. During emergency operations, the ESV pump restart is delayed for a short period of time in
8 order to allow for other, more time-critical loads to load onto the emergency power system. A variety of
8 non-nuclear safety-related data points associated with the ESV/SSW/ECCW systems are sent to the plant
8 computer.

8 The SSW System consists of two headers that are supplied water from the Low Pressure Service Water
8 (LPSW) system. Only one header is needed to supply all loads. However, both SSW headers are
8 normally in service so that a single failure in the LPSW system cannot cause a loss of safety function.
8 The SSW supply water routes from the Turbine Building to the ESV Building, where it is strained. Once
8 strained, SSW routes to the ESV pumps and to the CCW pumps. SSW provides an operating liquid for
8 the ESV pumps and provides sealing and cooling water the CCW pump shaft seal and motor bearing
8 cooler. The nuclear safety-related function of the SSW System is to provide the operating liquid to the
8 ESV pumps. The ESV pumps are liquid ring vacuum pumps which require a continuous supply of water
8 in order to create a vacuum. As the header branches to the ESV pumps and then branches to each ESV
8 pump individually, a solenoid valve is contained at each pump. This solenoid valve is interlocked with
8 the ESV pump control circuitry. The valve opens when the pump starts and closes when it stops. A
8 failure of one of these solenoids would cause a single ESV pump to be inoperable. The SSW system
8 function would not be affected, since it could successfully deliver water to the remaining ESV pumps.

8 The SSW system contains provisions for connection of a submersible pump to supply sealing/cooling
8 water to the CCW pumps. Both the ESV and SSW systems are designated as QA Condition I systems.
8 They are seismically designed and designed to continue functioning with a single, active failure. However,
8 they are not designed for tornado loads. Interfacing structures existing prior to the installation of these
8 systems are designated QA Condition 4. The ESV Building shell is also a QA Condition 4 structure.

9.2.3 AUXILIARY SERVICE WATER SYSTEM

9.2.3.1 Design Basis

The Auxiliary Service Water System is designed for decay heat removal following a concurrent loss of the
1 main feedwater system, Emergency Feedwater System, and Decay Heat Removal System. The system
will maintain decay heat removal for a minimum of 37 days.

9.2.3.2 System Description

The Auxiliary Service Water System utilizes the plant CCW intake and discharge conduits as a source of
7 raw cooling water for decay heat removal (Figure 10-8). These conduits are interconnected by crossovers
and unwatering lines. An Auxiliary Service Water Pump located in the Auxiliary Building at Elev. 771

takes its suction from the Oconee 2 intake conduit and discharges into the steam generators of each unit
1 via separate lines into the emergency feedwater headers. The raw water is vaporized in the steam
generator removing residual heat and dumped to the atmosphere.

The auxiliary service water pump is an end suction centrifugal pump with a rated capacity of 3000 gal/min
6 at a total head of 180 feet.

It has been submitted to the following tests:

1. A non-witness ASME hydro test
2. Witnessed performance test
3. Sonic testing of shaft
4. Mill test certificates for casing, impeller, and shaft
5. Certified caliper measurements

The pump power supply is taken from the 4160 volt Standby Bus No. 1.

All valves required for operation of the Auxiliary Service Water System are either check valves or
manually operated. The pump suction is equipped with a manually operated butterfly valve and the
7 discharge with a check valve and manually operated gate valve. The pump is equipped with a minimum
7 flow path to the CCW discharge crossover line, which is isolated by a globe valve. The individual lines to
6 each steam generator auxiliary feedwater header are equipped with a check valve and one normally closed
6 gate valve which is used to control flow. The majority of non-embedded piping is Duke Class F.

Atmospheric steam dumps on each main steam line are equipped with one normally closed gate valve and one normally closed control valve which must be opened to reduce steam generator shell side pressure before placing the Auxiliary Service Water System into operation.

9.2.4 ULTIMATE HEAT SINK

The Condenser Circulating Water System is the ultimate heat sink for Oconee Nuclear Station. This system is described in Section 9.2.2.2.1, "Condenser Circulating Water System (CCW)."

9.2.5 REFERENCES

5 1. Safety Evaluation Report for Oconee Units 2 and 3, dated July 6, 1973.

5 2. Letter from J. W. Hampton (Duke) to USNRC Document Control Desk, dated May 31, 1995,
5 Service Water Issues.

7 3. Letter from H. B. Tucker (Duke) to USNRC Document Control Desk, dated December 5, 1989,
7 NRC Bulletin No. 88-04 Potential Safety-Related Pump Loss Action 4 Report Status Update.

8 4. Letter from J. W. Hampton (Duke) to USNRC Document Control Desk, dated January 7, 1993,
8 "NRC Bulletin No. 88-04 Potential Safety-Related Pump Loss Revised Response".

8 5. Letter from L. A. Wiens (NRC) to J. W. Hampton (Duke), dated June 10, 1993, "Revised Response
8 to NRC Bulletin 88-04, "Safety Related Pump Loss".

8 6. Safety Evaluation Report for License Amendment 217/217/214, dated August 19, 1996.

8 7. Letter from H. B. Tucker (Duke) to USNRC Document Control Desk, dated January 26, 1990,
8 "Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related
8 Equipment".

8 8. Letter from H. B. Tucker (Duke) to USNRC Document Control Desk, dated May 31, 1990,
8 "Supplemental Response to NRC Generic Letter 89-13, Service Water System Problems Affecting
8 Safety-Related Equipment".

8 9. Letter from J. W. Hampton (Duke) to USNRC Document Control Desk, dated September 1, 1994,
8 "Generic Letter 89-13".

8 10. Letter from J. W. Hampton (Duke) to USNRC Document Control Desk, dated April 4, 1995,
8 "Supplemental Response #3 Generic Letter 89-13".

8 11. Letter from L. A. Wiens (NRC) to M. S. Tuckman (Duke), dated February 8, 1991, "NRC Generic
8 Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment".

8 12. Letter from J. W. Hampton (Duke) to USNRC Document Control Desk, dated July 12, 1995,
8 "Supplemental Response #4 to G. L. 89-13".

8 13. PIP 0-098-3629 Operability Evaluation

9.3 PROCESS AUXILIARIES

9.3.1 CHEMICAL ADDITION AND SAMPLING SYSTEM

9.3.1.1 Design Bases

Chemical addition and sampling operations are required to change and monitor the concentration of various chemicals in the Reactor Coolant System and Auxiliary Systems. The Chemical Addition and Sampling System is designed to add boric acid to the Reactor Coolant System for reactivity control, lithium hydroxide for pH control, and hydrazine for oxygen control. The Chemical Addition and Sampling System can also be used for hydrogen peroxide additions to induce 'crud' bursts during unit shutdowns to enhance corrosion product removal and, therefore, reduce equipment/system/component dose rates. Following a LOCA, the chemical addition and sampling system can be used to add sodium hydroxide (caustic) to the reactor coolant system for pH adjustment.

9.3.1.2 System Description and Evaluation

The Chemical Addition and Sampling System is shown schematically on Figure 9-15 and Figure 9-16. The Sampling System has separate sampling stations for reactor coolant and steam generator sampling for each of the three units. Two auxiliary systems sampling stations are provided, one for Oconee 1 and 2 and one for Oconee 3.

Two chemical addition systems are also provided, one for Oconee 1 and 2 and one for Oconee 3. These systems permit chemical addition to and sampling of the Reactor Coolant System and other Reactor Auxiliary Systems during normal reactor operation.

4 The Chemical Addition and Sampling System performs no emergency functions (Refer to Section 9.3.6,
4 "Post-Accident Sampling System" for information on Post-Accident Sampling System). Guidelines for maintaining feedwater and reactor coolant quality are derived from vendor recommendations and the current revisions of the EPRI PWR Secondary and Primary Water Chemistry Guidelines, respectively. Detailed operating specifications for the chemistry of these systems are addressed in the Chemistry Section Manual. A brief functional description of the major system components follows.

Boric Acid Mix Tank

7 Two Boric Acid Mix Tanks, one shared between units 1 and 2, and one for unit 3, are provided as a
7 source of concentrated boric acid solution. The volume of the tanks provides sufficient boric acid solution to increase the reactor coolant system boron concentration to that required for cold shutdown. Tank heaters and electrically heat traced transfer lines maintain the fluid temperature above that required to assure solubility of the boric acid.

Boric Acid Pumps

Six boric acid pumps, three shared between units 1 and 2, and three for Unit 3, are provided to transfer the concentrated boric acid solution from the boric acid tank to the borated water storage tank, letdown storage tanks, spent fuel storage pool, or the core flood tanks. Two pumps, each with a 1 gal/min capacity, supply boric acid to the core flood tanks. The other four pumps, which each have 10 gal/min capacities, supply boric acid to other tanks, systems, and locations (Figure 9-15 and Figure 9-16).

Caustic Mix Tank

Caustic addition serves the primary purpose of adding sodium hydroxide to the LPI system following a LOCA to minimize the zinc-boric acid reaction. Previously, this system was used to control the pH in the RC bleed and miscellaneous waste evaporators and to regenerate the resins in the deborating demineralizers, but it is no longer used in this capacity. A single caustic mix tank is provided for Units 1
5 and 2, and one tank is provided for Unit 3. These tanks would be used only as an alternative to the
5 caustic bulk storage containers.

Caustic Pump

5 The caustic pump transfers sodium hydroxide from caustic bulk storage containers or the caustic mix tank to the LPI system. A single pump is provided for Units 1 and 2 and one is provided for Unit 3.

Lithium Hydroxide Tank

Lithium hydroxide is mixed and added to the Reactor Coolant System for pH control from the lithium hydroxide tank. A single tank is provided for Units 1 and 2, and one tank is provided for Unit 3.

Lithium Hydroxide Pump

The lithium hydroxide pump transfers lithium hydroxide from the LiOH tank to the letdown line upstream of the letdown filters. A single pump is provided for Units 1 and 2, and one pump is provided for Unit 3.

3

0 Hydrazine Pumps

The hydrazine pump transfers hydrazine to the letdown line upstream of the letdown filters. The hydrazine pump, after sufficient demineralized water flushes, is also used to transfer hydrogen peroxide. A
3 single pump is provided for units 1&2, and one pump is provided for unit 3. These pumps can also be
3 used as a backup to the Lithium Hydroxide pump or to add other chemicals (as needed) to the RCS.

0 A separate hydrazine pump transfers hydrazine from a small container backwards through the pressurizer
0 water space sample line to the pressurizer. Each unit has its own separate pump.

Pressurizer Sample Cooler

This cooler cools the effluent sample taken from the pressurizer steam or water space. One cooler is provided per unit.

Steam Generator Sample Cooler

This cooler cools the effluent sample taken from the secondary side of the steam generator. Two coolers are provided per unit.

9.3.1.2.1 Mode of Operation

The chemical addition portion of this system delivers the necessary chemicals to other systems as required. Boric acid is provided to the spent fuel pool, borated water storage tank, letdown storage tank, and core flooding tanks as makeup for leakage or to change the concentration of boric acid in the associated systems. Sodium hydroxide is added to the LPI system following a LOCA to minimize the zinc-boric acid reaction. The sampling portion of this system is used to take samples to assure that water qualities and boric acid concentrations are maintained. Sampling locations and the samples taken at each location are as follows:

<u>Liquids</u>

9 Primary Sample Basin

1. Steam Generator Sample Sink
   - a. Secondary Side of Steam Generator
2. Reactor Coolant Sample Sink
   - a. Pressurizer Water Space
   - b. Pressurizer Steam Space
   - c. Low Pressurizer Injection Cooler Outlet
   - d. Core Flooding Tanks
   - e. Total Gas Sample
   - 0 f. Reactor Coolant

9 Waste Disposal Sample Basin

3. Auxiliary Systems Sample Sink
   - a. Purification Demineralizer Inlet and Outlet
   - b. Deborating Demineralizer Outlet
   - c. Letdown Storage Tank Water Space
   - 7 d. RC Bleed Evaporator Feed Pump Discharge (out of service)
   - e. Deborating Demineralizer Outlet (Regeneration)
   - 7 f. Waste Evaporator Feed Pump Discharge (out of service)
   - 7 g. RC Bleed Evaporator (Concentrate) (out of service)
   - 8 h. Concentrated Boric Acid Storage Tank Pump Discharge
   - 7 i. RC Bleed Evaporator (Distillate) (out of service)
   - 7 j. Waste Evaporator (Concentrate) (out of service)
   - k. RC Bleed Transfer Pump Discharge
   - l. Waste Transfer Pump Discharge
   - m. High Activity Waste Transfer Pump Discharge
   - n. Low Activity Waste Transfer Pump Discharge
   - 7 o. Condensate Test Tank Pump Discharge (out of service)
   - 7 p. RC Bleed Evaporator Demineralizer Outlet (out of service)
   - q. Reactor Building Normal Sump
   - 7 r. Waste Evaporator (distillate) (out of service)

<u>Gaseous</u>

6 1. Hydrogen Analyzer

6 a. Containment

9 2. Gas Analyzer (Unit 1 and 3) (out of serice)

9 a. Waste Holdup Tank

9 b. High Activity Waste Tank

9 c. RC Bleed Holdup Tanks

9 d. Waste Gas Vent Header

9 e. RC Bleed Evaporator (Unit 1 only)

9 f. Waste Evaporator (Unit 1 only)

9 g. Waste Gas Decay Tanks

9 h. H_2 Purge Station

9 3. Sample Containers (to be analyzed for a variety of substances)

9 a. Letdown Storage Tank Gas Space

9 b. Pressurizer Steam and Water Space

9 c. Gas Analyzer Sample (out of service)

9.3.1.2.2 Reliability Considerations

The Chemical Addition and Sampling System is not required to function during an emergency condition. Redundant boric acid pumps and flow paths are provided to guard against a single component failure rendering the system inadequate for boron addition. In addition to the boric acid mix tank, boric acid is also available for boration in 5-percent by weight solution from the concentrated boric acid storage tank. To prevent precipitation, heating/heat tracing is installed on components and lines used to transfer concentrated boric acid. The pumps, tanks, coolers, and instrumentation are located in the Auxiliary Building and are accessible for inspection and maintenance.

9.3.1.2.3 Codes and Standards

The components of the Chemical Addition and Sampling System are designed to the codes and standards noted in Table 9-5.

9.3.1.2.4 System Isolation

0 The pressurizer sample line, core flood sample line, and both steam generator sample lines are the only
0 system lines that penetrate the Reactor Building. All these lines contain electric motor-operated isolation
0 valves inside the Reactor Building and pneumatic valves outside, which are automatically closed by an
0 engineered safeguards signal (except for the core flood sample line which has a manual isolation valve).

9.3.1.2.5 Leakage Considerations

Leakage of radioactive reactor coolant from this system within the Reactor Building will be collected in the Reactor Building normal sump. Leakage of radioactive gases from this system outside the Reactor Building is collected by placing the sampling stations under hoods exhausting to the unit vent.

9.3.1.2.6 Failure Considerations

7 Since the system serves no engineered safeguards function, the only consideration immediately following a
7 loss-of-coolant accident is the operation of the isolation valves. Redundant isolation valves are provided
to assure isolation of the Reactor Building as described in Section 9.3.1.2.4, "System Isolation."

9.3.1.2.7 Operational Limits

The Chemical Addition and Sampling System provides certain chemicals to several systems in proper quantities and concentrations and provides a capability to sample fluids in various systems. The limits that must be maintained on these operations are described below.

The boric acid mix tank solution is to be maintained above an average temperature of 105°F in order to
maintain boric acid in solution at a concentration of 7 percent by weight. The capacity of the boric acid
8 mix tank is 500 cubic feet. The volume of boric acid required to borate to cold shutdown near end of
8 core life is cycle specific. (See Core Operating Limits Report)

9.3.2 HIGH PRESSURE INJECTION SYSTEM

9.3.2.1 Design Bases

The High Pressure Injection System is designed to accommodate the following function during normal reactor operation:

1. Supply the Reactor Coolant System with fill and operational makeup water.
2. Provide seal injection water for the reactor coolant pumps.
3. Provide for purification of the reactor coolant to remove corrosion and fission products.
4. Control the boric acid concentration in the reactor coolant.
5. In conjunction with the pressurizer, the system will accommodate temporary changes in reactor coolant volume due to small temperature changes.
6. Maintain the proper concentration of hydrogen and corrosion inhibiting chemicals in the Reactor Coolant System.
7. Provides continuous flow for cooling the normal HPI nozzles (see FSAR Section 5.4.7.2, "High Pressure Injection") to minimize thermal shock.
8. Provides auxiliary pressurizer spray control for cooldown when normal pressurizer spray is unavailable.

The specific design bases for various parts of the system are as follows:

<u>Letdown Capability</u>

The system will accommodate letdown required as a result of coolant volume expansion when heating the reactor coolant to operating temperature at a rate of 100°F/h while maintaining constant pressurizer level. The letdown is cooled before leaving the Reactor Building.

<u>Purification</u>

Filters and demineralizers are provided to remove reactor coolant impurities. The letdown filters and purification demineralizers are sized for full flow through the letdown orifice.

Makeup

The system will accommodate makeup requirements during design reactor coolant system transients and for Reactor Coolant System cooldown at the design rate.

9.3.2.2 System Description and Evaluation

The High Pressure Injection System is shown schematically on Figure 9-17 and Figure 9-18. Table 9-6 and Table 9-7 list the system Performance requirements and data for individual components. The following is a brief functional description of system components:

Letdown Cooler

The letdown cooler reduces the temperature of the letdown flow from the Reactor Coolant System to a temperature suitable for demineralization and injection to the reactor coolant pump seals. Heat in the letdown coolers is rejected to the Component Cooling System.

Letdown Flow Control

The letdown flow rate at reactor operating pressure is limited by a fixed block orifice. At reduced pressure a parallel, normally closed, remotely operated valve can be opened to maintain the desired flow rate. In addition there is a second parallel, normally closed valve which may be manually positioned for flow control.

3

Purification Demineralizer

The letdown flow is passed through the purification demineralizer to remove reactor coolant impurities other than boron. The design purification letdown flow is equal to one Reactor Coolant System volume in 24 hours. One demineralizer is provided for each unit. In addition, a spare demineralizer is shared between Oconee 1 and 2, and another spare is installed for Oconee 3. The spare demineralizer may be used to remove lithium from the reactor coolant system to maintain system chemistry and/or used to remove cesium from the reactor coolant system in the event of fuel defects. Chapter 11, "Radioactive Waste Management" describes coolant activities, coolant handling and storage, and expected limits on activity discharge.

Letdown Filters

Two letdown filters in parallel are provided to prevent particulates from entering the Reactor Coolant System and subsequently the pump seal filters. One filter is normally in use.

High Pressure Injection Pumps

The high pressure injection pumps are designed to return coolant which is letdown for purification to the Reactor Coolant System, and to supply the seal water to the reactor coolant pumps. The pumps are sized to permit one pump to provide normal operating makeup and seal water flow.

Reactor Coolant Pump Seal Injection Filters

Two reactor coolant pump seal filters are provided to prevent particulates from entering the pump seals. One is normally in use.

Seal Return filter

A single filter is installed in the seal return line upstream of the seal return coolers to remove particulate matter. A bypass is installed to permit servicing during operation.

Reactor Coolant Pump Seal Return Coolers

The seal return coolers are sized to remove the heat added by the high pressure injection pumps and the heat picked up in passage through the reactor coolant pump seals. Heat from these coolers is rejected to the Recirculated Cooling Water System. Two coolers are provided and one is normally in operation.

Letdown Storage Tank

The letdown storage tank serves as a receiver for letdown, seal return, chemical addition, and system makeup. The tank also accommodates temporary changes in system coolant volume.

9.3.2.2.1 Mode of Operation

During normal operation of the Reactor Coolant System, one high pressure injection pump continuously supplies high pressure water from the letdown storage tank to the seals of each of the reactor coolant pumps and to a makeup line connection to one of the reactor inlet lines. Makeup flow to the Reactor Coolant System is regulated by a flow control valve, which operates on signals from the pressurizer level controller.

A control valve in the common injection line to the pump seals automatically maintains the desired total injection flow to the seals. Manual Throttle valves in each pump seal injection line provide a capability to balance the seal injection flow rates. A portion of the water supplied to the seals enters the Reactor Coolant System. The remainder returns to the letdown storage tank after passing through one of the two reactor coolant pump seal return coolers.

On Oconee 1 only, when the leakage rate past the No. 1 face seal on any operating reactor coolant pump is less than 1 gal/min, the isolation valve in the seal bypass line is opened allowing flow of injection water past the lower radial pump bearing for cooling and lubrication. Provision is also made for filling the No. 3 (vapor) seal standpipe from the No. 1 seal water return line to the Letdown Storage Tank for Oconee 1 only.

Seal water inleakage to the Reactor Coolant system requires a continuous letdown of reactor coolant to maintain the desired pressurizer level. Letdown is also required for removal of impurities and boric acid from the reactor coolant. The letdown is cooled by one of the letdown coolers, reduced in pressure by the letdown orifice, and then passed through the purification demineralizer to a three-way valve which directs the coolant to the letdown storage tank or to the Coolant Storage System.

Normally, the three-way valve is positioned to direct the letdown flow to the letdown storage tank. If the boric acid concentration in the reactor coolant is to be reduced, the three-way valve is positioned to divert the letdown flow to the Coolant Storage System. Boric acid is removed by directing the letdown flow through a deborating demineralizer with the effluent returned directly to the letdown storage tank, or by the feed and bleed method. Feed and bleed is the process of directing the letdown flow to a coolant bleed holdup tank and maintaining the level in the letdown storage tank with demineralized water pumped from a supply of unborated water. The flow of demineralized water is measured and totaled by inline flow instrumentation. The flow of demineralized or borated water returning to the letdown storage tank is controlled remotely by the makeup control valve. During normal operation the inline instrumentation or the control rod drive interlock will terminate makeup flow.

The letdown storage tank also receives chemicals for addition to the reactor coolant. A hydrogen overpressure is maintained in the tank to assure a slight amount of excess hydrogen in the circulating reactor coolant. Other chemicals are injected in solution into the tank.

System control is accomplished remotely from the control room with the exception of the reactor coolant pump seal return cooling. The letdown flow rate is set by remotely positioning the letdown flow control valve to pass the desired flow rate. The spare purification demineralizer can be placed in service by remote positioning of the demineralizer isolation valves. The letdown flow to the Coolant Storage System is diverted by remote positioning of the three-way valve and the valves in the Coolant Storage System. The reactor coolant volume control valve is automatically controlled by the pressurizer level controller.

A continuous cooling flow is maintained through the HPI nozzle warming lines. Flow is monitored via the Operator Aid Computer with signals from a flow transmitter on each warming line.

Auxiliary pressurizer spray is remote manually controlled from the control room. No means exists for directly monitoring auxiliary pressurizer spray flow. Instead, pressurizer level is utilized for process monitoring of auxiliary pressurizer spray.

For emergency operation as a High Pressure Injection System, the normal letdown coolant flow line and the normal pump seal return line are closed, and additional makeup flow is supplied through the high pressure injection emergency lines. The pumps and pump motors are designed to be able to operate at the higher flow rates and lower discharge pressures associated with emergency high pressure injection requirements. Emergency operation of this system is described in Chapter 6, "Engineered Safeguards."

9.3.2.2.2 Reliability Considerations

This system provides essential functions for the normal operation of the unit. Redundant components and alternate flow paths have been provided to improve system reliability.

Each unit has three high-pressure injection pumps, each capable of supplying the required reactor coolant pump seal and makeup flow. One is normally in operation while another is in standby status to be used as needed. The third pump is used only for emergency injection. There are two letdown coolers and two seal return coolers. One cooler in each group will perform the required duty while the other may be used as a spare.

8 One of the two letdown filters or reactor coolant pump seal filters is normally in use while the other is a
spare.

9.3.2.2.3 Codes and Standards

Each component of this system will be designed to the code or standard, as applicable, noted in Table 9-7.

9.3.2.2.4 System Isolation

The letdown line and reactor coolant pump seal return line are outflow lines which penetrate the Reactor
Building. Both lines contain electric motor-operated isolation valves inside the Reactor Building and
7 pneumatic valves outside which are automatically closed by an engineered safeguards signal. The injection
7 lines to the reactor coolant pump seals are inflow lines penetrating the Reactor Building. These lines
7 contain a check valve on the inside and on the outside of the Reactor Building. Check valves in the
discharge of each high pressure injection pump provide further backup for Reactor Building isolation. The two emergency coolant injection lines are used for injecting coolant to the reactor vessel after a loss-of-coolant accident. After use of the lines for emergency injection is discontinued the electric

motor-operated isolation valves in each line outside the Reactor Building may be closed for isolation.
7 The HPI nozzle warming line and auxiliary pressurizer spray line are inflow lines penetrating the Reactor
7 Building. These lines each contain a check valve on the inside and on the outside for Reactor Building isolation.

9.3.2.2.5 Leakage Considerations

Design and installation of the components and piping in the High Pressure Injection System considers the radioactive service of this system. Except where flanged connections have been installed for ease of
2 maintenance, the system is an all-welded system.

9.3.2.2.6 Failure Considerations

The effects of failure and malfunctions in the High Pressure Injection System concurrent with a
7 loss-of-coolant accident are presented in Chapter 6, "Engineered Safeguards." These analyses show that redundant safety features are provided where required.

For pipe failures in the High Pressure Injection System, the consequences depend upon the location of the rupture. If the rupture were to occur between the reactor coolant loop and the first isolation valve or check valve, it would lead to an uncontrolled loss-of-coolant from the Reactor Coolant System. The analysis of this loss-of-coolant Accident is included in Chapter 15, "Accident Analyses." If the rupture were to occur beyond the first isolation valve or outside the Reactor Building, the release of radioactivity would be limited by the small line sizes and by closing of the isolation or check valve.

A single failure will not prevent boration when desired for reactivity control, since several alternate paths are available for adding boron to the Reactor Coolant System. These are: (a) through the normal makeup lines, (b) through the reactor coolant pump seals, and (c) through the emergency injection lines. If pump suction is unavailable from the letdown storage tank, a source of borated water is available from
8 the borated water storage tank during normal operation.

9.3.2.2.7 Operational Limits

Alarms or interlocks are provided to limit variables or conditions of operation that could cause system upsets. The variables or conditions of operation that are limited are as follows:

1. Letdown Storage Tank Level

   Low water level in the letdown storage tank is alarmed and interlocked to the three-way bleed valve. Low water level will switch the three way valve from the bleed position to is normal position.

2. Letdown Line Temperature

   A high letdown temperature in the letdown line downstream of the letdown coolers is alarmed and interlocked to close the pneumatic letdown isolation valve, thus protecting the purification demineralizer resins.

3. Dilution Control

   The dilution cycle is initiated by the operator. Several safeguards are incorporated into the design to prevent inadvertent excessive dilution of the reactor coolant.

3 a. The dilution valves have an automatic feature such that the operator may preset the desired
3 quantity of dilution volume before initiating the dilution cycle. The dilution cycle will terminate
3 when flow has integrated to the desired batch size. This interlock may be manually bypassed.
3 Operation in the automatic mode is the preferred method of dilution.

3 b. Interlocks on the regulating control rod bank automatically terminates the dilution cycle regardless
3 of the mode of operation the controller is in, automatic or manual, if the regulating rod group
3 (Group 6) is inserted into the core beyond 25 percent.

3 c. The operator may manually terminate the dilution cycle at any time.

9.3.3 LOW PRESSURE INJECTION SYSTEM

9.3.3.1 Design Bases

The Low Pressure Injection System removes decay heat from the core and sensible heat from the Reactor
2 Coolant System during the latter stages of cooldown. It provides the means for filling and draining the
2 fuel transfer canal. The system maintains the reactor coolant temperature during refueling and reduced
2 inventory operation. The LPI and support system(s), selected components of the RCS and HPI are
2 dedicated to prevention and mitigation of loss of Decay Heat Removal events. (See Section 16.5.3 in the
2 Selected Licensee Commitments Manual.)

2 In the event of a loss-of-coolant accident, the system injects borated water into the reactor vessel for longterm emergency cooling. The emergency functions of this system are described in Chapter 6, "Engineered Safeguards." Performance data is listed in Table 9-8.

9.3.3.2 System Description and Evaluation

The Low Pressure Injection System is shown schematically in Figure 9-19. An independent system is provided for each unit. The Low Pressure Injection System normally takes suction from the reactor coolant outlet line and delivers the water back to the reactor through the core flooding nozzles after passing through the low pressure injection pumps and coolers. The Low Pressure Injection System may be lined up when the reactor pressure is below the system suction piping design pressure for cooldown of the system to refueling temperatures. The decay heat is transferred to the Low Pressure Service Water System by the decay heat removal coolers. Component data are shown in Table 9-9.

The major system components are described as follows:

<u>Decay Heat Removal Pumps</u>

Three decay heat removal pumps are arranged in parallel with electric motor operated valves in the
7 suction line to each pump. Each pump has a separate minimum flow recirculation line with an orifice
7 between pump discharge and pump suction. The bore of each orifice was increased to address
7 considerations detailed in IEB 88-04, Safety Related Pump Loss. The two outboard pumps are normally
7 available for emergency operation, and the center pump is valved off on both the suction and discharge
7 sides of the pump. During decay heat removal, any two of the three pumps are lined up to the decay heat
7 removal coolers.

The design flow is that required to cool the Reactor Coolant System from 250°F to 140°F in 14 hours. The steam generators are used to reduce the Reactor Coolant System from operating temperature to the 250°F temperature.

<u>Decay Heat Removal Coolers</u>

The decay heat removal coolers, during a routine shutdown, remove the decay heat from the circulated reactor coolant. Both coolers are designed to cool the circulated reactor coolant from 250°F to 140°F in 14 hours.

Borated Water Storage Tank

3 The borated water storage tank is located outside the Reactor Building and the Auxiliary Building. It
3 contains borated water with boron concentration maintained in accordance with the Core Operating
3 Limits Report. It is used for filling the fuel transfer canal during refueling and for filling the incore
3 instrumentation handling tank. The borated water storage tank also provides borated water for emergency
core cooling and the Reactor Building Spray System. Liquid level in the borated water storage tank is
monitored by redundant level instrumentation.

9.3.3.2.1 Mode of Operation

2 Two pumps and two coolers normally perform the decay heat removal function for each unit. The steam
2 generators reduce the reactor coolant temperature to approximately 250°F and pressure to approximately
4 300 psig. These conditions represent upper limits for starting an LPI pump so as to avoid exceeding
2 system design limits. For Oconee Units 1 and 2, when these temperatures and pressures are reached,
2 decay heat removal will be initiated by aligning the system in one of two possible "switchover"
2 configurations. The first (preferred) path aligns A and C pumps to RCS through newly installed high
2 pressure piping. With either the A or C pump operating, fluid is returned to the RCS through the "A"
2 train of LPI. The second (alternate) path aligns the B cooler to the RCS and the outlet of the cooler is
2 routed to the suction of the A and C pumps. In this alignment, the pump in service will return fluid to
2 the RCS through the "B" train of LPI. After the RCS pressure has been reduced to approximately 125
2 psig, the system is aligned so that two pumps take suction from the reactor outlet line and discharge
2 through two coolers.

4 For Oconee 3 decay heat cooling is initiated at 290 psig/250°F by aligning pumps to take suction from the
reactor outlet line and discharge through the coolers into the reactor vessel. The equipment utilized for
decay heat cooling is also used for low pressure injection during accident conditions.

During refueling, the decay heat from the reactor core is rejected to the low pressure injection coolers in the same manner as it is during cooldown to 140°F. At the beginning of the refueling period, both coolers and both pumps are required to maintain 140°F in the core and fuel transfer canal. Later, as core decay heat decreases, one cooler and pump can maintain the required 140°F.

The fuel transfer canal may be filled by switching the suction of the decay heat removal pumps from the reactor outlet to the borated water storage tank. When the transfer canal is filled, suction to the pumps is switched back to the reactor outlet pipe. (Normally filled with the spent fuel cooling pumps as described in Section 9.1.3, "Spent Fuel Cooling System.")

After refueling, the transfer canal is drained by switching the discharge of one of the pumps from the reactor injection nozzle to the borated water storage tank. The other pump will continue the recirculation mode of decay heat removal.

9.3.3.2.2 Reliability Considerations

Since the equipment is designed to perform both normal and emergency functions, separate and redundant flow paths and equipment are provided to prevent a single component failure from reducing the system performance below a safe level. All rotating equipment and most valves are located in the Auxiliary Building to facilitate maintenance and periodic operational testing and inspection.

9.3.3.2.3 Codes and Standards

Each component of this system will be designed to the code or standard, as applicable, as noted in Table 9-9.

9.3.3.2.4 System Isolation

The Low Pressure Injection System is connected to the reactor outlet line on the suction side and to the reactor vessel on the discharge side. The system is isolated from the Reactor Building on the suction side by two electric motor-operated valves located inside the Reactor Building and one electric motor-operated valve located outside the Reactor Building. The discharge side is isolated from the Reactor Building by a check valve inside and an electric motor-operated valve outside the Reactor Building. All of these valves are normally closed whenever the reactor is in the operating condition. In the event of a loss-of-coolant accident, the valve on the discharge side opens, but the valves between the reactor vessel and the suction side of the pumps remain closed throughout the accident.

9.3.3.2.5 Leakage Considerations

During reactor power operation, all equipment of the Low Pressure Injection System is idle, and all isolation valves are closed. Under loss-of-coolant accident conditions, fission products may be recirculated in the coolant through the exterior piping system. Potential leaks have been evaluated to obtain the total radiation dose to the public due to leakage from this system. The evaluation is discussed in Chapter 12, "Radiation Protection."

9.3.3.2.6 Operational Limits

Alarms or interlocks are provided to limit variables or conditions of operation that might affect system or station safety. These variables or conditions of operation are as follows:

<u>Decay Heat Removal Flow Rate</u>

Low flow from the pumps during the decay heat removal mode of operation is alarmed to signify a reduction or stoppage of flow and cooling to the core.

<u>Reactor Coolant Pressure Interlock</u>

The first valve from the Reactor Coolant System in the suction line to the low pressure injection pumps is interlocked with the Reactor Coolant System pressure instrumentation to prevent inadvertent overpressurization of the Low Pressure Injection System piping while the Reactor Coolant System is still above Low Pressure Injection System design pressure.

<u>Reactor Coolant Leaving Decay Heat Removal Coolers</u>

High temperature of the reactor coolant discharging from the decay heat removal coolers is alarmed to signal a loss of cooling capability in the respective cooler.

4 9.3.3.2.7 Failure Considerations

4 The effects of failure and malfunctions in the Low Pressure Injection System concurrent with a
7 loss-of-coolant accident are presented in Section 6.3.3.4, "Single Failure Assumption." Redundant safety
4 features are provided where required.

4 For pipe failures in the Low Pressure Injection System, the consequences depend upon the location of the
4 rupture. If the rupture were to occur between the first check valve upstream of the core flood nozzle and
4 the vessel, this would lead to a loss-of-coolant accident. The analysis of this loss-of-coolant accident is
4 included in Chapter 15, "Accident Analyses." Section 15.14.4.3, "Small Break LOCA" addressed this
4 failure as one of the limiting small break. Reference ECCS Analysis of B&W 177 FA
4 LOWERED-LOOP NSS Rev. 3 (BAW-10103A, Rev. 3 Topical Report July 1977).

9.3.4 COOLANT STORAGE SYSTEM

9.3.4.1 Design Bases

The Coolant Storage System for each unit is designed to accommodate the accumulated coolant bleed over a core cycle, including startup expansion and coolant letdown to storage for boric acid reduction.

Two coolant bleed holdup tanks, each with a capacity of 11,000 ft^3, are provided for each unit. One tank
2 provides storage for the reactor coolant bleed prior to treatment by the Radwaste Facility or makeup to
2 the Reactor Coolant System. The other tank provides additional storage and is used to store clean water
2 for use as feed to the Reactor Coolant System. An additional tank is provided for storage of the
2 concentrated boric acid from the boric acid mix tank. The RC Bleed Evaporator and associated
2 equipment is not used for coolant processing. Coolant processing is performed by the Radwaste Facility.

2 The storage of reactor coolant bleed requires approximately 55 percent of the volume of the bleed holdup
tanks for each unit. The tanks for all three units are arranged so that they can be utilized to store liquid
from the other units if so desired.

8 The design volume of coolant removed from one unit during heatup and dilution from MODE 5 is
approximately 9600 ft^3. This occurs near the end of the core cycle when boric acid concentrations are
8 reduced. Earlier in core life, coolant is removed in smaller quantities to reduce boric acid concentrations.

An additional requirement for coolant storage is the partial drain which occurs during refueling. The coolant is removed in a batch of approximately 6100 ft^3. per unit and returned to the Reactor Coolant System upon completion of refueling. Thus, it occupies storage capacity only during the period of refueling. The required storage volume for refueling operations of 6100 ft^3. is less than 10 percent of the total available capacity.

A quench tank, located inside the Reactor Building, condenses and contains any effluent from the pressurizer safety valves. The quench tank is sized to condense one normal pressurizer steam volume without relieving to the Reactor Building atmosphere. A quench tank drain pump is provided for pumping the quench tank contents into the letdown storage tank. The reactor coolant which has leaked into the quench tank can be pumped directly back into the coolant system to avoid routing this leakage through the waste disposal system.

9.3.4.2 System Description and Evaluation

The Coolant Storage System is used for the collection and storage of reactor coolant liquid. The liquid is
received from the High Pressure Injection System both as a result of reactor coolant expansion during
startup and for boric acid concentration reduction during startup and normal operation. It is either
conveyed to coolant bleed holdup tanks for storage or passed through deborating demineralizers for boric
acid removal and returned as unborated makeup to the High Pressure Injection System. A spray nozzle
in the coolant bleed tanks on the inlet line allow some of the gases to be released. Recirculating the tank
7 allows further stripping action to occur. Liquid from the coolant bleed holdup tanks can be pumped to
7 the Radwaste Facility for processing. This is schematically shown in Figure 9-21 and Figure 9-18.
Component data is shown in Table 9-10.

The quench tank, located inside the Reactor Building, condenses and contains effluent from the
pressurizer safety valves and various vents. Liquid in the quench tank can be circulated through a cooler
2 for temperature control, sampled and the excess liquid pumped to the Letdown Storage Tank, coolant
bleed holdup tanks or the Liquid Waste Disposal System. This portion of the Coolant Storage System is
shown schematically on Figure 9-20.

The deborating demineralizers may also be loaded with mixed bed resin and used as purification demineralizers to support normal purification and boron/lithium coordination programs.

The coolant bleed holdup tanks and the concentrated boric acid storage tanks are vented to the gaseous waste vent header to provide for filling and emptying without overpressurization or causing a vacuum to exist. In addition, each tank is equipped with a relief valve and a vacuum breaker. Pressurized nitrogen can be supplied to each tank to allow purging.

Instruments and controls for operation of this system are located in the control rooms. Instruments and controls for the coolant bleed holdup tanks and pumps and for the concentrated boric acid storage tanks and pumps are duplicated on the auxiliary control boards.

9.3.5 COOLANT TREATMENT SYSTEM

The Coolant Treatment System was originally designed and installed to both store reactor coolant bleed and to treat RC bleed for recycling. Since the boron recycling portion of the original Coolant Treatment System never functioned properly, the coolant storage portion is the only part of the system still in use at Oconee. The Coolant Storage System is described in Section 9.3.4, "Coolant Storage System." Radwaste processing is described in Section 11.6.3, "Mechanical Systems."

9.3.6 POST-ACCIDENT SAMPLING SYSTEM

9.3.6.1 Post-Accident Liquid Sampling System

9.3.6.1.1 Design Bases

0 This system provides the capability to obtain and analyze a liquid Reactor Coolant System sample under accident (Reg. Guide 1.3 or 1.4 release of Fission products) conditions without incurring a radiation exposure to any individual in excess of five (5) rems whole body dose or 75 rems to extremities. The diluted liquid and dissolved gas samples obtained from the system have the capability to:

1. Provide information related to the extent of core damage that has occurred or may be occurring during accident.
2. Determine the types and quantities of fission products released to the containment in the liquid and gas phase and which may be released to the environment.
3. Provide information on coolant chemistry (i.e., boron concentration, dissolved gas, pH, etc.).

7 9.3.6.1.2 System Description and Evaluation

The Post-Accident Liquid Sample System consists of a sample panel that houses the tubing, valving, instrumentation and system components. The system is controlled and monitored remotely from the sample control panel. The system is schematically illustrated in Figure 9-22. There is one separate
5 system for each Oconee unit, located at elevation 771 + 0 in the auxiliary building.

The control panel actuates valves that are outside containment and before/after the sample enters/leaves the sampling panel. The remaining valves are controlled either by Operations from the control room or by Operations manually. All valves involving penetrations to the reactor building are normally closed except when sampling.

Selection of sample lines is provided on the sample control panel. The sampling sequence is described in Section 9.3.6.1.3, "Mode of Operation."

9.3.6.1.3 Mode of Operation

The operation of the Post-Accident Liquid Sampling System is sequenced as follows:

1. The post-accident liquid sampling panel (sampler) isolates a reactor coolant sample at a system pressure up to 2500 psig and system temperature up to 650°F. The reactor coolant is cooled such that the isolated (pressurized) sample is below 200°F.
2. The pressurized liquid sample is depressurized into an evacuated gas collection bomb.
3. Gases are further stripped from the depressurized liquid sample by bubbling nitrogen through the liquid sample into the evacuated gas collection bomb.
4. Stripped gases are diluted with a known quantity of nitrogen to atmospheric pressure.
5. A diluted gas grab sample is taken for remote lab analysis.
6. pH of the depressurized, degassed liquid sample is measured.
7. A measured quantity of liquid sample is collected and taken for radioisotopic and chemical analysis.

6 8. The sample panel is flushed (around the liquid and diluted gas grab samplers) through the sample
6 return line to containment in order to reduce local dose rates. In the event of unexpected internal
6 sample panel leakage, the sample panel sump may also be pumped through the sample return line to
6 containment.

9.3.6.2 Post-Accident Containment Air Sampling System

9.3.6.2.1 Design Bases

The system provides the capability to promptly (within three hours) obtain and analyze a containment air sample under accident conditions (Reg. Guide 1.3 or 1.4 release of fission products) without incurring a radiation exposure to any individual in excess of five (5) rems whole body dose or 75 rems to extremities. The system has the capability to:

1. Provide information related to the extent of core damage that has occurred or may be occurring during an accident.
2. Determine the types and quantities of fission products released to the containment atmosphere and which may be released to the environment

7 9.3.6.2.2 System Description and Evaluation

The Post-Accident Containment Air Sampling System consists of a sampler panel that houses the tubing, valving, instrumentation, and system components. The system is controlled and monitored remotely from the sampler control panel. The system is schematically illustrated in Figure 9-23. Oconee 1 and 2 share common sample and control panels. Oconee 3 has a completely separate system.

The sample panel is located in an area close to the containment that would normally have limited accessibility. The sampler control panel is located in an accessible area separate from the sampler panel location.

Existing sample lines to the online hydrogen monitors, through solenoid valves selection, become the sample source for the containment air sampling panel.

Selection of the monitor is by switching on the hydrogen monitor control panel. The sampling sequence is described in Section 9.3.6.2.3, "Mode of Operation."

The operator can complete the sampling sequence in 30 to 60 minutes. The combined time allotted for sampling and analysis will be well within 3 hours from the time a decision has been made to take a sample. Alternate power sources are provided to meet the 3-hour limit in case of a loss of off-site power.

9.3.6.2.3 Mode of Operation

The operation of the Post-Accident Containment Air Sampling System is sequenced as follows:

1. The Post-Accident Containment Sampling System isolates a known quantity of containment
8 atmosphere, moves this quantity through a particulate air filter and an activated charcoal cartridge for separation of iodine and particulates from the noble gases, and provides a sample of the diluted gas for analysis.
2. Dilution gas (nitrogen) is provided for dilution factor up to 10,000 to 1.
8 3. The sampling system flushes and purges all interior sample lines as soon as possible to reduce
8 personnel exposure dose rates.

9.3.7 CONTAINMENT HYDROGEN MONITORING SYSTEM

9.3.7.1 Design Bases

The containment Hydrogen Monitoring System provides continuous indication of hydrogen concentration in the containment atmosphere. The measurement capability is provided over the range of 0% to 10% hydrogen concentration under both positive and negative ambient pressures. A continuous indication of the hydrogen concentration is not required in the control room at all times during normal operation. If continuous indication of the hydrogen concentration is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of the safety injection.

9.3.7.2 System Description

The Containment Hydrogen Monitor System withdraws a sample from the containment under normal, LOCA or Post LOCA conditions. The sample is analysed and returned to the containment. The monitoring system is designed to monitor containment gas for percentage volume of hydrogen.

A system of sample taking tubing is installed in the containment to draw air samples from 5 different levels or areas. Each of the sample intake lines has a solenoid valve which is remotely operated from a control panel in the ventilation room. At the control panel a selector solenoid valve is used to provide air flow to the Hydrogen Analyser from the selected intake port. The Hydrogen Analyser panels and associated remote control panels are located in the ventilation room. Remote alarm and indication is provided in the control room. There are two trains of equipment for each unit.

Ten Hydrogen Analyzer intake ports are installed, (two each) in the following locations:

1. The top of the Containment Building Dome, Elevation 983′ ± 5″
2. The operational level as close to the vessel as practical, Elevation 844 + 0′ ± 10′
3. The basement area, Elevation 788′ + 0″ ± 10′
4. The radiation monitor/hydrogen recombiner inlet header, Elevation 827′ + 4″
5. The radiation monitor/hydrogen recombiner outlet header, Elevation 824′ + 0″

<u>Hydrogen Measurement</u>

Analysis is accomplished by using the well established principle of thermal conductivity measurements of gases. This technique utilizes a self-heating filament fixed in the center of a temperature-controlled metal cavity. The filament temperature is determined by the amount of heat conducted by the presence of gas from the filament of the cavity walls. Thermal conductivity varies with gas species, thereby causing the filament temperature to change as the gas in the cavity changes. Filament resistance changes with temperature therefore, by using two filaments in separate cavities and connecting them in an electrical bridge, the difference in thermal conductivity of gases in the separate cavities may be determined electrically.

Electrical zero is set by first introducing the same gas to both cavities, then adjusting the electrical bridge to balance, resulting in a zero output. As different gases are introduced to the two individual cavities, the bridge will become unbalanced, and the electrical output will amplify with increasing differences in thermal conductivity of the gases used.

The measurement of hydrogen in the presence of nitrogen, oxygen and water vapor is possible because the thermal conductivity of hydrogen is approximately seven times higher than nitrogen, oxygen or water vapor, which have nearly the same thermal conductivities (at the filament operational temperature of approximately 550°K). The measurement is accomplished by using a thermal conductivity measurement cell and a catalytic reactor. The sample first flows through the reference section of the cell, then passes through the sample section of the measuring cell that includes the catalyst. The catalyst is chosen so that post-LOCA iodine will not poison the catalyst bed. The change in sample composition, due to the catalytic reaction is therefore indicated by the difference in thermal conductivity of the sample hydrogen content, as measured in the sample and reference sides of the cell.

If an excess amount of oxygen does not exist in the sample for recombining all the hydrogen, oxygen can be provided ahead of the hydrogen analyzer. The amount of oxygen added is determined by the highest range of the analyzer.

<u>Alarms</u>

Alarms are provided for high hydrogen concentration, cell failure and loss of power. These alarms are available on the analyzer itself and as signals to the control room annunciator. Additional alarms on the analyzer itself include low instrument temperature, low sample flow, low gas pressure and common failure.

9.3.7.3 Safety Evaluation

The Containment Hydrogen Monitor System (CHMS) meets the requirements of NUREG-0737, Item II.F.1.6. The CHMS has both indicator and recorder readouts in the control room on one of the two redundant channels and a indicator readout on the second channel. The CHMS has a range of 0% to
7 10% of Hydrogen. The CHMS indicator loop has a system accuracy of 3.0% of the full scale. The CHMS hardwired recorder loop and all the CHMS plant process computer loops have a system accuracy of 2.6% of the full scale. These values will provide information over the intended range of the CHMS that is sufficiently accurate and useful to allow the plant operator to adequately assess the hydrogen concentration within containment. There are five ports to draw samples for each of the redundant hydrogen monitors. The system provides capability to rapidly detect Hydrogen from the reactor and determine its concentration throughout the containment.

9.4 AIR CONDITIONING, HEATING, COOLING AND VENTILATION SYSTEMS

0 ## 9.4.1 CONTROL ROOM VENTILATION

9.4.1.1 Design Bases

0 The Control Room Ventilation and Air Conditioning Systems are designed to maintain the environment
7 in the control area which is comprised of the Control Room, Cable Room and Electrical Equipment
Rooms as indicated on Figure 9-24 within acceptable limits for the operation of unit controls as necessary
7 for equipment and operating personnel. Redundant air conditioning & ventilation equipment is provided
7 as summarized in Section 3.11.5, "Loss of Ventilation" to assure that no single active failure within these
systems will prevent proper control area environmental control. Acceptable limits for equipment in the
9 cable rooms and for the electrical equipment rooms is 120°F and 100°F for the Control Room.

Design conditions for the Control Room are 74°F and 50 percent maximum relative humidity. The Equipment Room is designed for 86°F and all other areas, i.e., the Control Room Zone and Cable Room are designed for 74°F. Outdoor design conditions are 95°F dry bulb and 76°F wet bulb. The ventilation and air conditioning systems are designed for continuous operation.

The radiation monitor, RIA-39, has a continuous sample of control room air pumped through the detector. High radiation level and loss of sample flow are annunciated at which time the operator energizes the outside air filter trains. The outside air filter trains act to filter particulate matter from the outside air to minimize uncontrolled infiltration into the Control Room.

7 Control area temperatures related to Station Blackout are addressed by Selected Licensee Commitment
7 16.8.1. The pressurization and filtration of the control room envelope is discussed further in Section 6.4,
7 "Habitability Systems."

9.4.1.2 System Description

9.4.1.2.1 Control Room Oconee 1 and 2

The Control Room for Oconee 1 and 2 is shared for the operation of both units. The Control Room is
3 primarily served by two large air handling units. The units are 100 percent capacity and only one unit is
required to operate at a time. Cooling is provided to the Unit 1 Cable Room, Unit 2 Cable Room, Unit 1
7 Equipment Room, and Unit 2 Equipment Room by a total of four air handling units. An automated
8 damper control system will operate to maintain acceptable temperatures in the cable and electrical
8 equipment rooms if one of the cable rooms AHUs is out of service.

7

0 All of the air handling units described above consist of roughing filters, chilled water cooling coils, and
centrifugal fans. Chilled water is supplied to the units from the plant WC chilled water system. Electric
duct heaters are installed in the ductwork to provide heat to the different areas when necessary.

4 Outside air is supplied to the Control Room for pressurization purposes, from an intake on the Auxiliary
Building roof. Air passes through filter trains which consist of pre-filters, 99.5 percent efficient HEPA
3 filters, 90 percent efficient charcoal filter beds, and a centrifugal fan. There are two 50 percent filter trains

and the system is capable of operating with one train or both trains. During normal plant operations, the
filter trains are not energized and require operator action to start. The outside air is supplied to the return
0 air intake of the large air handling units which serve the Control Room. A radiation monitor is provided
in the return air intake of the air handling units to alert the operators in the Control Room on a high
radiation reading at which time the operators start the outside air filter trains. The filter trains are
8 designed for a flow of 1350 cfm each. The pressurization system was not designed or licensed to maintain
8 a positive pressure in the Control Room assuming a single failure.

7 Cooling is provided to the Cable Rooms and Electrical Equipment Rooms by four air handling units
located in the vicinity of the rooms.

0 Table 9-11 is a list of the air handling units and operation requirement for the Control Room and
Control Room Zone air conditioning system. Figure 9-24 is a schematic description of the ventilation
and air conditioning systems for the Control Room and Control Room Zone.

9.4.1.2.2 Control Room Oconee 3

7 The Oconee 3 Control area is comprised of the Control Room, the Cable Room, and the Electrical
4 Equipment Room. These areas are served by six air handling units. Two 100 percent air handling units
4 serve the Control Room, two 100 percent air handling units serve the Cable Room, and two 100 percent
air handling units serve the Electrical Equipment Room. The air handling units consist of roughing
0 filters, chilled water cooling coils, and centrifugal fans. Chilled water is supplied to the air handling units
by the Plant WC Chilled Water System.

8 Outside air is supplied to the Control Room for pressurization purposes by two 50% trains taking suction
from an intake on the Auxiliary Building roof. The outside air passes through a filter system composed of
3 a prefilter, 99.5 percent efficient HEPA filter, 90 percent efficient charcoal filter beds and centrifugal fan.
Outside air is supplied to the return air intake of the air handling units. The outside air system is started
8 by the plant operators. The pressurization system was not designed or licensed to maintain a positive
8 pressure in the Control Room assuming a single failure.

A radiation monitor is provided to sample the return air entering the Control Room and Control Room Zone air handling units. The monitor alarms on a high radiation signal and alerts the operators to energize the outside air filter system to minimize the infiltration of unfiltered air into the Control Room.

0 Table 9-11 lists the air handling unit and operation requirements. Figure 9-24 is a schematic
representation of the air conditioning system.

9.4.1.3 Safety Evaluation

The Control Room is served by redundant air handling units. The chilled water for the air handling units
is supplied from the Plant WC Chilled Water System which is capable of supplying sufficient chilled water
7 for all necessary systems with one of two chillers in service.

Return air from the Control Room is continuously monitored by a radiation monitor before recirculating
back to the Control Room. A high radiation level will alert the operators to energize the outside air filter
3 trains. The filter trains are 50 percent, each train consisting of a prefilter, HEPA filter, 90 percent efficient
charcoal filter bed and centrifugal fan. The filters act to filter particulate matter from the outside air
supplied to minimize uncontrolled infiltration into the Control Room.

9.4.1.4 Inspection and Testing Requirements

0 The Control Room Ventilation System is in continuous operation and is accessible for periodic
0 inspection. The Control Room pressurization portion of the system is tested periodically to demonstrate
its readiness and operability as required by the Technical Specifications.

9.4.2 SPENT FUEL POOL AREA VENTILATION SYSTEM

9.4.2.1 Design Bases

The Spent Fuel Pool Area Ventilation System is designed to maintain a suitable environment for the operation, maintenance and testing of equipment and also for personnel access. The ventilation system is designed to maintain the Spent Fuel Pool Area at a maximum inside temperature of 104°F and a minimum temperature of 60°F.

The path of ventilating air in the Spent Fuel Pool Area is from areas of low activity toward areas of progressively higher activity for discharge to the unit vent.

An air handling unit consisting of roughing filters, steam heating coil, cooling coil supplied by low pressure service water, and a centrifugal fan supply 100 percent outside air to the Spent Fuel Pool Area. Two methods of exhausting air from the Fuel Pool Area are provided, a filtered exhaust system and an unfiltered exhaust system. Normal operation is with the unfiltered system in operation. In the filter mode, the Fuel Pool Area ventilation air passes through a filter train consisting of prefilters, high efficiency particulate (HEPA) filters, charcoal filter and two 100 percent vane axial fans. The filtered exhaust system is operable whenever fuel handling operations above or in the fuel pool are in progress.

The Spent Fuel Pool Area air is continuously monitored by radiation monitor, RIA-41.

9.4.2.2 System Description

Ventilation air for the Spent Fuel Pool Area is supplied by an air handling unit which consists of roughing filters, steam heating coil, cooling coil supplied by low pressure service water, and a centrifugal fan. Temperature is maintained in the Spent Fuel Pool Area by throttling steam to the heating coil or low pressure service water to the cooling coil.

In the normal mode of operation, the air from the Spent Fuel Pool Area is exhausted directly to the unit vents by the general Auxiliary Building exhaust fans. When fuel handling operations are in progress, the filtered exhaust system must be operable so in the event of an emergency the air leaving the Fuel Pool Area can be filtered.

The filtered exhaust system consists of a single filter train and two 100 percent capacity vane axial fans.
The filter train utilized is the Reactor Building Purge Filter Train. The filter train is comprised of
0 prefilters, HEPA filters, and charcoal filters. An attempt to start the main Reactor Building purge fan will
stop the Spent Fuel Pool filtered ventilation.

To control the direction of air flow, i.e., to direct the air from the Fuel Pool Area to the Reactor Building
0 Purge Filter Train, a series of pneumatic motor operated dampers are provided along with a crossover
duct from the Fuel Pool to the filter train.

0 Figure 9-25 and Figure 9-26 are detailed diagramatics of the Spent Fuel Pool Area Ventilation System.
The flow paths as well as air quantities are given in the diagram.

9.4.2.3 Safety Evaluation

Prior to handling fuel in the Spent Fuel Pool Area, the Spent Fuel Pool Ventilation System must be made operable as required by the Technical Specifications.

There are two 100 percent capacity vane axial fans which direct the Spent Fuel Pool air through the Reactor Building Purge Filter Train prior to being released to the unit vent. Only one fan is required for operation. The fans are manually energized by the operators should it become necessary to filter the exhaust air from the Fuel Pool Area. The automatic control sequence is such that the damper alignment, to redirect air flow through the Reactor Building Purge Filters, is automatically done when one of the fans is energized.

An alarm is provided when the fuel pool filtered flow drops below 70 percent of design flow.

A radiation monitor is provided to continuously monitor the fuel pool air and will alarm on a high radiation level.

9.4.2.4 Inspection and Test Requirements

The normal mode of the Spent Fuel Pool Area Ventilation System is in continuous operation and is
0 accessible for periodic inspection. The filtering mode of the Spent Fuel Pool Area Ventilation system is
tested periodically to demonstrate its readiness and operability as required by the Technical Specifications.

9.4.3 AUXILIARY BUILDING VENTILATION SYSTEM

9.4.3.1 Design Bases

The Auxiliary Building Ventilation System is designed to provide a suitable environment for the operation, maintenance and testing of equipment and also for personnel access.

The Auxiliary Building Ventilation System serves all areas of the Auxiliary Building with the exception of the Control Room Area and the Penetration Rooms. The ventilation system is designed to maintain temperature limits during normal plant operation of 104°F and 60°F during summer and winter respectively.

Ventilation air is supplied to both clean and potentially contaminated areas within the Auxiliary Building. The flow path of the ventilation air in the Auxiliary Building is from clean or low activity areas towards areas of progressively higher activity.

0 All air from the Auxiliary Building is directed to the unit vent stacks at which point it is exhausted and
continuously monitored by a radiation monitor which alarms on high radiation levels. In addition, a
radiation monitor samples air throughout the Auxiliary Building Ventilation System. The detector output
0 is logged on a recorder in the Control Room. All air from the Hot Machine Shop is exhausted to the
0 atmosphere after being measured by an air flow monitor. Periodically, radiation levels are checked in the
0 air flow using an air flow totalizer and particulate sampler.

The exhaust fans and supply fans are manually balanced such that the exhaust flow exceeds the supply air flow to minimize outleakage.

9.4.3.2 System Description

The Auxiliary Building Ventilation System is comprised of the Auxiliary Building Ventilation System proper and the Hot Machine Shop as shown in Figure 9-27 and Figure 9-28. Air is supplied to the
0 Auxiliary Building by a low pressure fan duct system. Air is taken in through outside air intake louvers by supply units consisting of roughing filters, steam coil, and cooling coil supplied by low pressure service
0 water. There are six main supply fans, each required for normal plant operation. Auxiliary Building air is
0 exhausted from the building, via exhaust duct and exhaust fans, through three unit vent stacks.

0 The Hot Machine Shop air is supplied by two recirculating local cooling units. Each unit consists of
0 roughing filters, a compressor, evaporator and condenser coils, and centrifugal fan. These units supply
0 recirculated air with a small amount of make-up air throughout the Hot Machine Shop via a low pressure
0 duct system. Air is exhausted from the Hot Machine Shop via exhaust duct and filter train and is
0 discharged to the atmosphere through an independent vent stack.

Table 9-11 is a list of the primary equipment which comprises the Auxiliary Building Ventilation System
7 and the Hot Machine Shop Ventilation System. The list includes number of installed components and normal operation requirements.

Temperatures are maintained in the Auxiliary Building by throttling steam to the steam coils or low
0 pressure service water to the cooling coils as required. Temperatures are maintained in the Hot Machine
0 Shop by electric unit heaters in the supply ductwork. The Hot Machine Shop uses direct expansion (DX)
0 cooling.

Remote recirculating fan-coil type units provide standby spot cooling in the pump rooms and other high heat load areas. The fan coil units are also served by the Low Pressure Service Water System.

9.4.3.3 Safety Evaluation

Under normal operating conditions, the Auxiliary Building Ventilation System supply fans and exhaust fans are balanced such that the exhaust air flow exceeds the supply air flow in order to minimize outleakage.

All exhaust air from the Auxiliary Building is directed to the unit vents where it is monitored prior to
0 being released to the atmosphere. All exhaust air from the Hot Machine Shop is monitored prior to being
0 released to the atmosphere through an independent vent stack.

9.4.3.4 Inspection and Testing Requirements

0 The Auxiliary Building Ventilation System and the Hot Machine Shop Ventilation System are in
0 continuous operation and are readily accessible for periodic inspection and maintenance.

9.4.4 TURBINE BUILDING VENTILATION SYSTEM

9.4.4.1 Design Bases

The Turbine Building Ventilation System is designed to provide a suitable environment for the operation of equipment and personnel access as required for inspection, testing and maintenance.

9.4.4.2 System Description

The Turbine Building is ventilated using 100 percent outside air. Air is supplied through wall openings along the east wall and is exhausted by fans mounted in the roof and along the west wall.

3 There are twelve roof mounted exhaust fans. Eighteen additional exhaust fans are located along the west wall. Each of the thirty fans are independently operated so that all or a portion of the fans can run as needed to maintain conditions within the Turbine Building.

0 Table 9-11 is a list of the primary equipment which includes the Turbine Building Ventilation System
3 Exhaust Fans. The list includes number installed and normal operation requirements.

9.4.4.3 Safety Evaluation

The Turbine Building Ventilation System operates to maintain suitable environmental conditions in the Turbine Building during normal plant operation.

9.4.4.4 Inspection and Testing Requirements

The Turbine Building Ventilation System is in continuous operation during normal plant operation and is readily accessible for periodic inspection and maintenance.

9.4.5 REACTOR BUILDING PURGE SYSTEM

9.4.5.1 Design Bases

7 The Reactor Building Purge System purges the Reactor Building with fresh air during unit outages.

7 During operation, outside air is introduced into the Reactor Building through a supply system which has dual isolation valves at the containment wall. Outside air is circulated throughout the Reactor Building by the normal Reactor Building Ventilation System. Air is then exhausted from the Reactor Building by the Reactor Building purge exhaust filter train.

0 The filter train consists of prefilters, HEPA filters, and charcoal filters. A centrifugal fan is positioned
0 downstream of the filter train. There are double isolation valves in the piping running from the Reactor
Building to the filter train.

The isolation valves are automatic, are normally closed, and are opened only for the purging operation. The valves are arranged so the purge supply piping and the purge exhaust piping each have a electrically actuated valve inside the Reactor Building and a pneumatically actuated valve outside the Reactor Building.

7 There are two modes of operation possible for the Reactor Building Purge System; normal purge, and
7 mini-purge. The system also has a recirculation mode, however it is not used because of duct leakage
7 concerns. The purge filter train can also be used to provide filtered exhaust as discussed in Section 9.4.2,
"Spent Fuel Pool Area Ventilation System."

9.4.5.2 System Description

8 The "Reactor Building Purge System" (Figure 6-4) purges the Reactor Building with fresh air to reduce airborne contaminant levels inside the Reactor Building.

The supply portion of this system consists of an outside air intake louver, roughing filters, a steam heating coil, associated ductwork and dual isolation valves at the reactor building wall. The exhaust portion of this system consists of a filter train, fans, associated ductwork, and dual isolation valves at the Reactor Building wall. The filter train consists of prefilter, HEPA filter, and charcoal filter. The isolation valves are automatic, normally closed and are opened only for the purging operation. The valves are so arranged that the supply portion and exhaust portion of the system each have an electrically actuated isolation valve inside the Reactor Building and two (2) pneumatically operated valves outside the Reactor Building (one is an isolation valve). A bleed valve between the two (2) outer valves vents any leakage from the Reactor Building into the penetration room.

7 There are two modes of operation possible for the "Reactor Building Purge System": 1) the normal
7 purge, and 2) the mini-purge.

The normal purge mode purges the Reactor Building with 35,000 cfm of fresh air which enters by way of the supply portion and leaves by way of the exhaust portion described above. The filtered exhaust air is all released to the atmosphere via the unit vent.

The mini-purge mode of operation provides a means to purge the Reactor Building at a reduced flow rate when activity levels are higher than desired for full purging. A 10,000 cfm vane-axial fan is provided to by-pass the normal purge exhaust fan. A series of pneumatically operated dampers provide isolation and control. During mini-purge, flow from the Reactor Building is through the purge filter train and can be modulated up to a maximum of 10,000 cfm. The vane-axial mini-purge fan is constant volume and to maintain 10,000 cfm flow, Reactor Building air is mixed with outside air, i.e., the more air being purged from the Reactor Building, the less air drawn from the outside air make-up intake. The mini-purge fan and normal purge fan cannot operate simultaneously.

7

9.4.5.3 Safety Evaluation

Each Reactor Building Purge System supply and exhaust penetration of the Reactor Building wall is equipped with dual isolation valves. The valves inside the Reactor Building are electrically operated and
0 the valves outside the Reactor Building have pneumatic actuators. The valves operate independently of one another and are in the closed position unless the purge is in operation.

The Purge System discharge to the unit vent is monitored and alarmed to prevent the release from exceeding acceptable limits.

9.4.5.4 Inspection and Testing Requirements

The Reactor Building Purge System is normally not in operation. The equipment and component are accessible for periodic maintenance. Parts of the system are maintained and tested in accordance with the Technical Specifications.

9.4.6 REACTOR BUILDING COOLING SYSTEM

9.4.6.1 Design Bases

The Reactor Building Cooling Systems are designed to remove the heat in the containment atmosphere
2 during normal plant operation and post accident operation.

A portion of the Reactor Building Cooling System is described in Section 6.2.2, "Containment Heat Removal Systems" as an Engineered Safety Feature.

The Reactor Building Cooling System is composed of two subsystems: Reactor Building Coolers and Reactor Building Auxiliary Coolers.

All components of the Reactor Building Cooling System are inside the Reactor Building. The only penetrations into and out of the Reactor Building that are related to the cooling system are the low pressure service water supply and return lines and isolation valves are provided on these lines at the penetrations.

9.4.6.2 System Description

8 The Reactor Building Cooling System shown in Figure 6-3 consists of the following subsystems and
components:

4 1. Three Reactor Building Cooling Units (RBCUs), each consisting of a 2-speed vane axial fan, four
cooling coils and distribution ductwork. These three cooling units are Engineered Safety Systems.

2. Four Reactor Building Auxiliary Cooling Units, each consisting of a 2-speed vane axial fan, four cooling coils, and distribution ductwork.

6 During normal plant operation, the A and C Reactor Building Cooling Units may operate in the high
speed mode. These units circulate Reactor Building air over low pressure service water supplied cooling
0 coils and distribute the cool air throughout the lower portion of the Reactor Building. Low pressure
6 service water supplied to the B RBCU may be diverted to four Auxiliary Cooling Units. Two EMO-ES
valves (LPSW-565 and LPSW-566) provided in the Low Pressure Service Water System divert the water
0 from the B RBCU to the Auxiliary Cooling Units. This low pressure service water supplies the four
0 cooling coils that comprise each Auxiliary Cooling Unit. The four auxiliary cooling unit fans are operated
0 in the high speed mode. The Auxiliary Cooling Units distribute the cool air via a duct system to the
upper portion of the Reactor Building. The temperature in the Reactor Building can be controlled by
varying the number of Auxiliary Cooling Units running.

8 LPSW is simultaneously aligned to the "B" RBCU and the auxiliary coolers (reference 1). This
8 alignment ensures sufficient flow is maintained through a RBCU to prevent condensation induced
8 waterhammers which are not bounded by existing analysis. This alignment also allows LPSW to supply
8 the auxiliary cooling units for reactor building temperature control.

During an emergency, the Reactor Building Cooling System mode of operation changes automatically.
6 Upon receipt of the signal from the Engineered Safeguards Actuation System, the operating Reactor
6 Building Cooling Units change to low speed operation and any idle unit(s) is energized at low speed. The
fans are run at the slower speed because of the changed horsepower requirements generated by the denser
building atmosphere. Also on the ES signal, the EMO valves, in the Low Pressure Service Water System,
0 which diverted water from the B RBCU to the Auxiliary Cooling Units are re-aligned. Valve LPSW-565
8 closes, stopping water flow to the Auxiliary Coolers. Valve LPSW-566 opens, if not already full open,
0 allowing water flow to the B RBCU. Additionally, all Low Pressure Service Water valves at the discharge
0 of the three RBCUs go to the full open position.

0 The accident may impose severe stresses on the lower portion of the duct work, causing possible collapse
0 or deformation. Therefore, the fusible links holding the dropout plates provided in the duct work below
the coils melt and drop off, assuring that a positive path for recirculation of the Reactor Building
atmosphere is available.

0

9.4.6.3 Safety Evaluation

9 The three Reactor Building Cooling Units (RBCUs) are an engineered safety feature. These units alone
9 can provide the design heat removal capacity to keep containment pressure below the design limit
following a loss-of-coolant accident with all three coolers operating by continuously circulating the steam-air mixture past the cooling tubes to transfer heat from the containment atmosphere to the low pressure service water.

8

Inside the Reactor Building, the cooling units are located outside the secondary shield at an elevation above the water level in the bottom of the Reactor Building during post-accident conditions. In this location, the units are protected from being flooded.

The major equipment of the Reactor Building Cooling Units is arranged in three independent strings with three duplicate service water supply lines. In the unlikely event of a failure in one of the three cooling
7 units, half of the Reactor Building Spray System capacity combined with the remaining two cooling units,
9 is capable of keeping the containment temperature and pressure within environmental qualification (EQ)
9 limits and is capable of keeping containment pressure below the design limit after a loss-of-coolant or
9 steam line break accident. Acceptable fan-motor operation is verified by testing each refueling outage.

A failure analysis of the cooling units is presented in Table 6-6.

9.4.6.4 Inspection and Testing Requirements

8 See "Tests and Inspections" under Section 6.2.2, "Containment Heat Removal Systems."

9.4.7 REACTOR BUILDING PENETRATION ROOM VENTILATION SYSTEM

9.4.7.1 Design Bases

This system is designed to collect and process potential Reactor Building penetration leakage to minimize environmental activity levels resulting from post-accident Reactor Building leaks. Experience has shown that Reactor Building leakage is more likely at penetrations than through the liner plates or weld joints.

The main function of the system is to control and minimize the release of radioactive materials from the Reactor Building to the environment in post-accident conditions. When the system is in operation, a
0 negative pressure with respect to surrounding areas will be maintained in the penetration room to ensure
inleakage.

Leakage into each of the penetration rooms is discharged to the unit vent through a pair of filter assemblies each consisting of a prefilter, an absolute filter, and a charcoal filter in series. The entire system is designed to operate under negative pressure up to the fan discharge.

The Penetration Room Ventilation System is not vulnerable to control malfunctions since it is controlled manually. Instrumentation is used only to monitor system performance and has no control function other than to guide the operator in adjusting the final control elements.

7 More detailed information concerning radiation levels and leakage requirements are discussed in Section
7 6.5.1, "Engineered Safeguards (ES) Filter Systems."

9.4.7.2 System Description

The Penetration Room Ventilation System is provided with two fans and two filter assemblies. Both fans
0 discharge through a single line to the unit vent. A schematic of the system is shown in Figure 6-4.

During normal operation, this system is held on standby with each fan aligned with a filter assembly. The
0 engineered safeguards signal from the Reactor Building pressure will actuate the fans. The Control room,
0 as well as remote instrumentation, monitors operation.

The design flow rate from the penetration room far exceeds the maximum anticipated Reactor Building
1 leakage. The design leak rate of .125 volume percent per day from the Reactor Building to the
1 penetration room (this is one-half of the total design leak rate out of the Reactor Building referenced in
1 Section 6.2.1, "Containment Functional Design") amounts to approximately 7.8 scfm compared to a design evacuation rate of 1000 scfm for each half of the system. The three valves in each purge line penetration will be closed by Reactor Building isolation signal. The Reactor Building Purge Equipment, if running, will be shut down from an interlock on the Reactor Building Purge isolation valves. After closing of the external valves, a small normally open valve vents the leakage, if any, from the two outermost valves into the penetration room. The Reactor Building Purge Equipment is not activated when the reactor is above cold shutdown conditions.

Following a loss-of-coolant accident, a Reactor Building isolation signal will place the system in operation by starting both full-size fans. Two power-operated butterfly valves which open when the fans start are provided at the discharge of each fan. This valve will be closed to prevent recirculation if one fan fails. A check valve is also provided at the discharge of each fan to prevent recirculation on failure of a fan. In the event of a fan failure, the normally closed tie valve (PR-20) can be opened from its remote manual station
9 to maintain cooling air through the idle filter train. Even if air flow is lost through a filter train, Reference
9 2 has shown that the charcoal ignition temperature will not be reached and operation of PR-20 is not
9 required.

The system utilizes remote manual control valves PR-13 and PR-17 in conjunction with constant speed fans to provide the proper negative pressure in the penetration room. Locations of penetrations and
7 openings in the penetration room are shown on Figure 6-23 and Figure 6-24. If during operation the
0 leakage increases causing a decrease in negative pressure below 0.06 inches H_2O with respect to the
0 outside atmosphere, the remote manual control valve will be adjusted or leaks will be repaired to bring the negative pressure to .06 inches H_2O or greater.

The remote manual control valve is also used to compensate for filter loading. Initially, it will be partially closed; and as the filter loads up causing a decrease in flow and negative penetration room pressure, the valve will gradually be opened so that the pressure drop across the filter-valve combination remains constant. By periodically adjusting the remote manual control valve to offset the effect of increased leakage and filter loading, the system characteristic remains constant.

The communicative paths between various parts of the penetration room are very large in comparison with the minute leakage that might exist due to imperfect seals. It therefore can be assumed that no pressure differentials exist in the room so that an instrument string sensing pressure at a single point can be used. Penetration room pressure is displayed in the control room and excessive and insufficient vacuum are annunciated.

Fan status and radiation level of filter effluent are displayed in the control room and excessive radiation is annunciated. Filter ΔP is displayed locally. Filter flow is displayed remotely adjacent to the remote manual control valves PR-13 and PR-17 remote control stations.

8 The system may be actuated by an operator during normal operation for testing. It may also operate
8 intermittently during normal conditions as required to maintain satisfactory temperature in the
8 penetrations rooms.

Particulate filtration is achieved by a medium efficiency pre-filter and a high efficiency (HEPA) filter.

The pre-filter consists of multiple horizontal tubular bags attached to a vertical metal plate header. The bags are made of ultra fine glass fibers and are supported so that adjacent bags do not touch and reduce the flow area. At the filter train design flow of 1000 cfm, the pre-filter is operating at one-half its rated flow.

The HEPA filter will intercept any particulates that pass through the pre-filter. The filter consists of a single cell of fiber glass media mounted in a metal frame. The cell has face dimensions of 24 inches x 24 inches and a depth of 11½ inches and is rated at 1150 scfm.

0 Adsorption filtration is accomplished by an activated charcoal filter. The filter consists of three horizontal
removable type double tray carbon cells. Flow through the trays is essentially vertical. Each tray has a
face area of 4.2 sq ft and a bed depth of 2 inches. At rated flow (167 cfm), the average face velocity is 40
ft/min and the residence time is 0.25 seconds. Each tray contains 40 lbs of carbon. The carbon is
0 impregnated so that it will adsorb methyl iodide as well as elemental iodine.

9.4.7.3 Safety Evaluation

The fans and filter trains for the system are redundant and only one fan and one filter train is required for emergency operation. Refer to Table 6-19 for a failure analysis of the system.

9.4.7.4 Inspection and Test Requirements

The Penetration Room Ventilation System is not normally in operation, but the equipment is accessible for periodic inspection. The entire system can be tested during normal operation. Testing and inspection of the system shall be as required by the Technical Specifications.

8 ## 9.4.8 REFERENCES

8 1. PIP 0-098-3629 Operability Evaluation.

9 2. OSC-4024, PIR 4-090-0057, Operability Evaluation: PRVS Inoperability Due to Valves PR-13,
9 PR-17, and PR-20, Attachment #4, Rev. 1.

9.5 OTHER AUXILIARY SYSTEMS

0 **Note**

0 This section of the FSAR contains information on the design bases and design criteria of this
0 system/structure. Additional information that may assist the reader in understanding this system is
0 contained in the design basis document (DBD) for this system/structure.

9.5.1 FIRE PROTECTION SYSTEM

9.5.1.1 Design Bases

The overall fire protection program is based on an evaluation of the potential fire hazards in the Auxiliary, Reactor Buildings, adjacent areas of the Turbine Building and the effect of postulated design basis fires relative to maintaining the ability to perform safe shutdown functions and minimize radioactive releases to the environment.

7 Total reliance is not placed on a single automatic fire suppression method. Fire hose stations, fixed
7 sprinklers, Halon and CO_2 fire suppression systems, and portable extinguishers are provided.

9.5.1.2 System Description and Evaluation

The High Pressure Service Water System (HPSW) provides water for the fire protection system at Oconee. Two 6,000 gal/min (at 117 psig) pumps and one 500 gal/min (at 117 psig) jockey pump supply the HPSW System.

The 500 gal/min jockey pump normally operates to maintain the system pressure on the fire protection headers. In the event of a fire, one 6000 gal/min pump will automatically provide sufficient water for maintaining elevated water storage tank inventory. The second 6000 gal/min pump is considered to be a spare.

5 Pump suctions are connected to the Condenser Circulating Water (CCW) crossover header. Service water
5 may be supplied by the CCW inlet headers for any Oconee Unit.

If power to the CCW pumps is lost, the emergency discharge to the Keowee hydro tailrace will
3 automatically open and the system would continue to function as an unassisted syphon. CCW normal
flow is 177,000 gal/min with each of the twelve (12) pumps.

A 100,000 gallon elevated storage tank is connected to the HPSW system. This tank serves as a source of water should the demand of the HPSW system exceed the capacity of the HPSW jockey pump. If the tank level should drop to 70,000 gallons, one HPSW pump will start. If the tank level continues to drop to 60,000 gallons, the second HPSW pump will start. The HPSW pumps will continue to run until the tank level reaches the 90,000 gallons (approximate) level and then cut off.

Power to the jockey pump is provided from 600V Motor Control Center 1XE located at Elevation 775 which is normally fed from 600V load center 1X3 located at Elevation 796 with an alternate supply from 600V load center 1X2 at Elevation 796. The jockey pump is located in Unit 2 along with HPSW pump B. Power to HPSW pump B is furnished directly from 4160V Bus No. 1 Unit No. 1.

HPSW Pump A is located in Oconee 1 and power is furnished directly from 4160V Bus. No. 2 Unit No. 1.

Power to these pumps may be fed from Oconee 1, 2 or 3; through the 230 KV and/or 525 KV systems; Unit 1 or 2 of Keowee Hydro Units; or from Combustion Turbines located at Lee Steam Station. These alternate sources, including the emergency power from Keowee, assure that the fire protection system will not be lost due to a single failure.

Failure or inadvertent operation of an automatic fire suppression system will not incapacitate redundant safe shutdown systems or functions.

New reactor fuel is stored in the Spent Fuel Pool prior to installation in the reactor. Hazards evaluations performed on this area (Spent Fuel Pool Area) revealed an insignificant amount of combustibles ordinarily in the area and that fire protection by portable fire extinguisher is acceptable.

Equipment required for safe shutdown is not shared between units except for the LPSW and CCW Systems. This arrangement has been evaluated and is acceptable.

7 Keowee Hydro Station Water Spray and Fire Hose systems are provided water by a separate Service
7 Water (SW) system. A portable pump is provided and may be used in establishing a backup fire fighting
7 system.

9.5.1.3 Administrative Procedures and Controls

Administrative procedures consistent with the need for maintaining the performance of the Fire Protection
System and personnel have been established at the Oconee Nuclear Station. These procedures have been
4 established at the Oconee Nuclear Station through the use of Site Directives and other station documents.
Guidance incorporated in the following publications has been utilized as much as practical:

NFPA-4 - Organization for Fire Services

NFPA-6 - Industrial Fire Loss Prevention

NFPA-7 - Management of Fire Emergencies

NFPA-8 - Management Responsibility for Effects of Fire on Operations

NFPA-27 - Private Fire Brigades

NRC Document - Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance.

7 Nuclear System Directive 313, "Control of Combustible and Flammable Material" states the parameters
7 of allowable storage of combustible materials for Oconee. Periodic inspections by insurance
5 representatives and station personnel assure adherence to the Directive.

Reviews are conducted of work requests by the Oconee Planning Section to determine the effects of these activities on station fire barriers or stops. This identification then alerts personnel to special precautions which must be taken.

1. Work involving ignition sources such as welding and burning is performed under closely controlled
7 conditions. Nuclear System Directive 314 has been written to cover these activities in areas which
7 have not been approved specifically by the Site Fire Protection Engineer. This directive has been
developed by personnel experienced in fire protection to provide guidance and precautions for fire
protection when welding or burning. Provisions of the directive require the establishment of clear

zones, preparation of floors, considerations of the ventilation systems and openings to adjacent rooms. Proper use of shielding materials is also required to protect equipment from the possibility of stray sparks. Prior to the initiation of welding or burning, the area must be inspected by a trained individual and written permission must be given. Fire watches, trained in the use of fire fighting equipment and methods of reporting fires are stationed during and for thirty minutes after the welding
4 or burning takes place. The Site Fire Protection Engineer audits the welding and burning program to assure its proper implementation.

2. Leak testing and similar procedures such as air flow determination use commercially available aerosol techniques.

3. Provisions for the bulk storage of combustible material such as HEPA filters, carbon filters, and dry
7 ion exchange resins are described in Nuclear System Directive 313. Procedures have been developed to control the transient storage of these materials during periods of replacement. The use of wood inside buildings containing safety-related systems or components is permitted only when suitable non-combustibles are not available. If wood is required, only fire retardant treated wood is used.

The Oconee Nuclear Station organization has been staffed and equipped to be self sufficient regarding
3 fire situations which might arise in the protected area. The Emergency Coordinator has the authority to utilize offsite fire departments. The local fire departments receive annual training.

In order to assure the capability to successfully contain a fire it is necessary to perform testing and maintenance of fire detection, fire fighting, fire protection equipment, emergency lighting and communications equipment. This is accomplished through the station periodic test program in which the performance of equipment is verified through actual testing as in the case of pumps or inspection and verification for such items as hoses and fire extinguishers. The responsibility for completion of these tests is not assigned to specific individuals but rather are assigned to responsible groups within the station organization to be performed at established frequencies. Testing is not considered necessary for the communication system since it also serves as the normal system and is in continuous use. Deficiencies identified as a result of inspections and use are reported and corrected.

7 Nuclear System Directive 316 has been developed to provide for the reporting and appropriate
7 corrective action to be taken in the event fire protection/detection equipment has been determined to
7 be, or is scheduled to be inoperable. Specific priorities have been established for expediting repairs to this equipment. Additional surveillance is specified as well as other necessary supplementary actions.
4 Fire protection/detection equipment will not be taken out of service without notifying the Site Fire
4 Protection Engineer.

7 The Oconee Fire Brigade organization is addressed by Nuclear System Directive 112 which describes
7 the functions and duties of each position and identifies individuals by title to fill these positions. The
7 organization provides for a Fire Brigade Leader and Shift Coverage.

Fire brigade training is provided in accordance with the Nuclear Production Department Fire Protection Training and Qualification Manual or commitments made to NRC.

9.5.1.4 General Guidelines for Plant Protection

9.5.1.4.1 Building Design

1. Plant layout separates safe shutdown systems from unacceptable fire hazards.

9 2. The Fire Protection Review analysis, (currently contained in the Fire Protection DBD), will be reviewed and updated as necessary.

3. See Section 9.5.1.6.3, "Cable Spreading Room" for cable room comments.

4. Interior wall and structural components and radiation shielding are non-combustible. Coatings are non-combustible with flame spread and fuel contribution of 50 or less.

5. There is no metal roof deck construction related to safe shutdown systems at Oconee, with the exception of the Turbine Building.
6. Suspended ceilings and their supports are non-combustible. Combustibles in this area are minimal.
7. Transformers installed in buildings containing safety related systems are not oil-filled, except for CT-4, which is located in the Unit 1/2 Blockhouse.
8. Transformers which are oil-filled and within 50 feet of a building containing safety related systems are protected with an automatic water spray system.
9. Floor drains are sized to remove fire protection water in locations where suppression systems are present, with exception of the cable spread rooms, equipment rooms, cable shafts and personnel hatch areas.
10. Redundant systems and equipment essential for a dedicated safe shutdown are separated by fire rated barriers.

7 11. Keowee Hydro Station does not have committed fire rated barriers due to its remote location.

9.5.1.4.2 Control of Combustibles

1. Safe shutdown systems are separated from combustible materials except for those required for operation.
2. There is no bulk gas storage in areas affecting safe shutdown equipment.
3. Power and control cable at Oconee is covered with a PVC jacket. Refer to Section 9.5.1.4.3, "Electric Cable Construction, Cable Tray and Cable Penetrations" (6) for discussion of construction and use of cable at Oconee.
4. Storage of flammable liquids comply with NFPA 30, "Flammable and Combustible Liquids Code." The governing edition of NFPA 30 is the edition current when the storage area is designed.

   An exception is the SSF Diesel Generator Fuel Oil Day Tank, which is as follows:

   - NFPA-30, Section 2.4.4.3 requires a "normally closed remotely activated valve... on each liquid transfer connection below the liquid level...to provide for quick cutoff of flow in the event of a fire in the vicinity of the tank."

   Since the fuel oil transfer pumps are positive displacement type and all piping connected to the storage tank is Duke Class B (seismic design), the intent of this section is met.

9.5.1.4.3 Electric Cable Construction, Cable Tray and Cable Penetrations

1. Cable trays are constructed from non-combustible materials.
2. See Section 9.5.1.6.3, "Cable Spreading Room."

7 3. Cable splices in raceways are not permitted. Current carrying capacity (ampacity) in power cables is
7 typically designed at 70 percent of manufacturers recommendation as a workplace engineering and
7 design criteria. However, other derating factors may be applied based upon IEEE S-135, ICEA
7 P-46-426 depending upon individual power cable installation specifications. These additional derating
7 factors may be more conservative than the 30 percent derating of manufacturers recommendation. On
7 this basis, the potential of internally generated faults with ensuing fires is considered remote; therefore,
7 protection of the cable insulation and jacketing from an internally initiated fire is not required.

9 4. The Oconee station is required to provide penetration seals in fire, flood and pressure (HVAC)
9 boundaries. No special penetration seal designs are installed to provide radiation shielding protection.
9 There is a Duke Power Nuclear Generation Department Penetration Seal Specification (Reference 21)
9 and Design Basis Calculation (Reference 22) which contains the approved materials and generic

9 penetration seal design configuration. Each identified Oconee penetration seal is contained in the
9 Oconee Equipment Database with references back to the generic qualified design configuration in the
9 corporate documents or in the site specific calculation (Reference 20). The site specific calculation
9 contains the penetration seals that have had an equivalency evaluation per the guidelines established
9 in the NRC Generic Letter 86-10.

9 The fire barrier and their penetration seal must meet the following acceptance criteria to meet our
9 licensing basis, as discussed below:

9 <u>Electrical Penetration Seals</u>

9 Electrical penetration seal designs shall be subjected to a standard exposure fire that follows the
9 ASTM E-119 Standard Time-Temperature Curve.

9 The acceptance criteria from IEEE 634 (which is identical to that of IEEE P634/D4) shall be used to
9 evaluate the acceptability of test assemblies. The IEEE 634 acceptance limit for ONS unexposed side
9 electrical penetration temperature shall be 700°F. This temperature was selected because the IEEE
9 634 acceptance criteria is the auto-ignition temperature of the outer cable covering and material in
9 contact with the cable penetration fire stop, or 700°F, whichever is lower. The ignition temperature
9 of outer cable jacketing has been determined to be 735°F.

9 <u>Mechanical Penetration</u>

9 Mechanical penetration seal designs shall be subjected to a standard exposure fire that follows the
9 ASTM E-119 Standard Time-Temperature Curve.

9 The acceptance criteria from IEEE-634 (which is identical to that of IEEE P634/D4) shall be used to
9 evaluate the acceptability of test assemblies. The IEEE 634 acceptance limit for Duke Power
9 mechanical penetration seals shall be 680°F. This temperature was selected because it represents the
9 lowest auto ignition temperature of any material normally found in close proximity to piping
9 penetrations (Armstrong Armalok pipe insulation).

7 5. Cable routings and separation are adequate to preclude the loss of safe shutdown capability by a
7 single fire hazard. Current carrying capability (ampacity) of power cables is derated by 30 percent of
7 manufacturer's rating as a workplace design criterion. However, other additional derating factors may
7 be applied based upon IEEE S-135, ICEA P-46-426 depending upon individual specifications of
7 installations. These additional factors may be more conservative than the single 30 percent derating.

6. The cable used at Oconee is classified as either power, control or instrumentation.

The 5 and 8 KV cables are three conductor power cables. The tinned copper conductors are covered with a semi-conductive extruded strand shield, insulated with ethylene propylene rubber (EPR) and wrapped with a tinned copper shield tape. The three conductors are then twisted with a flame retardant non-hygroscopic filler, bound together with binders tape, encased in a 25 mil galvanized steel interlocked armor jacket and covered with a flame retardant polyvinyl chloride (PVC) jacket.

The three conductor 2KV power cable, which is used for 600 V systems, is constructed the same as the 5 and 8 KV cable except that a hypalon or neoprene jacket has been applied over the EPR insulation in lieu of the tinned copper shield tape.

Control cables are multi-conductor cables. The tinned copper conductor has EPR insulation with the hypalon or neoprene jacket over the singles; the singles have been twisted with the flame retardant non-hygroscopic fillers and covered with an asbestos mylar binder tape. This is encased in 25 mil galvanized steel interlocked armor with a polyvinyl-chloride jacket.

Instrumentation cable (outside the containment) is single or multipaired cable consisting of #16 AWG copper conductor with PVC insulation. The singles are paired and twisted with an aluminum mylar shield with PVC jacket and overall served wire armor encased in a flame retardant PVC jacket.

Instrumentation (inside containment) is multi-conductor and paired cables consisting of #16 AWG, tinned copper conductors insulated with EPR and hypalon jacket. This is twisted with flame retardant fillers, wrapped with an asbestos mylar binder tape and encased in 25 mil galvanized steel interlocked armor with a flame retardant PVC jacket overall.

The use of armor on cables ensures they are more resistant to fire, mechanical damage and electrostatic and electromagnetic interferences. The armor also provides protection from short circuits and overloads.

7. Any new cable installed at Oconee will be constructed similar to the cable presently used at the station.

7 8. Cables are located in dedicated cable support systems. These systems include: cable tray, conduit,
7 cable troughs, electray and trenches. Piping is not routed in cable tray, conduit, cable troughs or
7 electray. Cables and piping do not routinely occupy the same trench. In specific instances, cable and
7 piping may share the same trench. Where cable and piping must share the same trench, an evaluation
7 will be performed to justify acceptability of joint occupancy prior to placing cables in pipe trenches or
7 pipes in cable trenches. Trenches are typically external to plant buildings. Pipes carrying combustible
7 gases or liquids are not permitted in cable trenches and likewise, cables will not be permitted in pipe
7 trenches where piping carries combustible gases or liquids. Miscellaneous storage is not permitted in
7 cable support systems or in trenches. There are no other fire hazards present in cable support
7 systems.

9. The cable rooms, the equipment rooms and the cable shafts are provided with smoke venting capabilities. Portable purge fans would augment installed equipment.

10. Only those cables which are required are routed to the control room. Cables entering the control
7 room terminate there. There are no power and control cables in the concealed floor or ceiling space,
7 except for miscellaneous power and network cables in the ceiling space supplying small OAC
7 computer room equipment. Therefore, a fire suppression system is not required in this area.

9.5.1.4.4 Ventilation

9 1. At Oconee, separate ventilation systems serve the Unit 1/2 and Unit 3 control rooms. Normal
9 ventilation is provided through one of two air handling units on each Oconee Control Room which
9 condition recirculated air.

9 The Oconee Unit 1/2 Control Room and the Oconee Unit 3 Control Room have similar but separate
9 pressurization systems. For each control room, pressurization and ventilation air is brought from the
9 outside via the outside air booster fans and associated filters. The fresh air intakes for the booster fans
9 are located on the Auxiliary Building roof. The air is sent through the two redundant fan and filter
9 units after which it mixes with return air in the nomal recirculated ventilation flowpath. The mixed air
9 is then conditioned and conveyed to the control room. The filters have isolation valves at their inlets
9 which will be closed unless the fans are energized. The fans run only during an emergency and during
9 testing.

9 2. For cable and equipment rooms, air handling units condition recirculated air. A common ventilation
9 system serves the cable and equipment rooms for Units 1 and 2. A connecting cable shaft between the
9 cable and equipment rooms is used to convey cool air to the equipment rooms to supplement cooling
9 from smaller cooling units dedicated to the equipment rooms. Some air passes from the Oconee Unit
9 1 equipment room to the Oconee Unit 2 equipment room to maintain air balance conditions. In Unit
9 3, the equipment and cable rooms are equipped with individual air handling units and the air handling
9 units are balanced.

9 3. Provision is made to remove smoke from the cable and equipment rooms and from the Unit 3
9 Control Room via smoke purge fans.

In Oconee 1 and 2, the smoke purge fan is located in the wall of Oconee 2 equipment room. The fan would remove smoke from the Oconee Units 1 and 2 cable rooms and Oconee Units 1 and 2 equipment rooms. The purge fan is flow rated at approximately 3000 CFM and is available to purge smoke to the Auxiliary Building corridor where it would be transported by the Auxiliary Building HVAC equipment, monitored and exhausted through the unit vent.

The Oconee Unit 1/2 control room would be purged with portable equipment.

In Oconee Unit 3, two smoke purge exhaust ducts are furnished for the equipment room and kitchen area of the control room. These exhaust ducts enable the equipment room, cable room and the control room to be purged in the event of a fire. The fan for purging smoke on Oconee 3 is located on Elevation 838+0 with HVAC equipment and would exhaust to that area enabling the Auxiliary Building System to pick up, monitor and discharge products of combustion through the unit vent.

In the event of purging, the cable shaft between the cable and equipment rooms would be used to carry smoke from the cable room to the equipment room.

Neither a single failure nor an inadvertent operation of the smoke purge systems would adversely affect plant operations. A single failure would require portable equipment be used to purge individual areas.

4. The Reactor Building's ventilation systems are designed to remove normal heat loss from equipment. A Reactor Building purge system is provided to purge the containment with fresh air when circumstances dictate. The purge equipment (fans, filter, etc) for the Reactor Building, except for interior ducts, is located outside the Reactor Building. The purge exhaust is filtered, monitored and alarmed prior to discharge to the atmosphere to prevent releases exceeding acceptable limits.

   The operation of the Reactor Building purge system is monitored from the control rooms. Monitors and alarms are provided to indicate the status of the system. Triple isolation valves are provided at the Reactor Buldings' penetrations. In the unlikely event of an inadvertent operation, the fact that the air is filtered, monitored and alarmed prior to discharge, assures that the protection for the public would be maintained.

5. The power and controls for the HVAC units serving the control rooms, cable rooms and equipment rooms are located at the air handling units.

6. Escape and access routes will be established by pre-fire plan and practiced in drills by operating and fire brigade personnel.

7. Due to construction arrangement and discharge limitations, smoke and heat vents are not applicable.

8. Self-contained breathing apparatus, using full face positive pressure masks, approved by either NIOSH or US Bureau of Mines are provided for fire brigade, damage control and control room personnel.

   Air for refilling the air packs is provided from a breathing air compressor with a cascade system. The compressor is powered from a non-load shed source.

9. Keowee Hydro Station shares no ventilation equipment with Oconee. Keowee is designed for remote operation from the Oconee Control rooms, and automatic operation in the event of Engineered Safeguards Actuation. Should the Keowee Control Room become uninhabitable, Keowee operation is not precluded due to operator absence.

9.5.1.4.5 Lighting and Communication

In addition to the normal ac lighting system, for each unit two separate emergency lighting systems are provided. These are an emergency 250V dc lighting system and a separate engineered safeguards 208Y/120 volt ac lighting system. These two systems are separate and distinct.

1. Fixed emergency dc lighting is fed from batteries that supply power for at least one hour.

Since two ac lighting systems and one dc emergency lighting system are provided this is considered adequate.

The engineered safeguards lighting system (ac), which is normally de-energized, provides lighting in the Auxiliary Building to enable personnel to leave or enter as necessary. Power is provided from two engineered safeguards 600 volt ac control centers through two 600/208Y/120 volt ac dry type transformers which in turn feed each of two panel boards located in the equipment room area. The engineered safeguard lighting is energized automatically by undervoltage sensing relays monitoring the normal 600 volt ac feeder voltage.

The 250 volt dc lighting system, which is normally de-energized, provides operating level lighting in
9 the control room and lighting at selected areas in the Auxiliary, Turbine, Reactor, Administrative, and
9 Service Buildings. The emergency lighting is energized automatically by an undervoltage sensing relay mounted on individual panel boards located in their associated areas. Control power for the under-voltage transfer circuit is provided from the 250 volt dc station batteries. A test button is also provided at each panelboard to test the operability of the system without affecting normal lighting. Associated lighting units are incandescent.

2. Sealed beam portable lights are provided for fire brigade personnel.

3. Pathways from the Units 1/2 and Unit 3 control rooms to the SSF and from the Control Rooms to valve FDW-315 for each unit have normal and emergency lighting and, in addition, have 8-hour battery backed emergency lighting units. This includes at least one stairwell and corridor from each control room leading to an outside door of the Auxiliary Building, which leads to the SSF.

   Outside the Auxiliary Building, the area is normally well lit by daylight or by security lighting, powered from several sources.

   The SSF has 1½ hour battery backed emergency lighting which is backed by the SSF Diesel Generator.

   In addition, flashlights and spare batteries are available in the Control Rooms for operators to use.

8 4. The primary method of communication is a PABX Telephone system with outside as well as in-plant connections. In conjunction with the telephone, a page system is used for calls throughout the plant. Each telephone is marked with the emergency reporting numbers.

8

5. Radio communication is available with base stations in the Unit 1/2 control room and the security office. Portable radios are available at each of these locations. The fixed repeater is located above the
8 Unit 1/2 Control Room in the Ventilation Equipment Room. If the repeater is unavailable, the
8 portable radios can operate at reduced transmission ranges on the radio to radio channel.

8 Sound powered telephones are located throughout the plant as an available but non-supported system
8 in addition to the telephone-page system.

7 6. Keowee Hydro Station has the ability to provide its own power for lighting loads. DC emergency
7 lighting is available throughout the station. Flashlights are provided for the Keowee operators.

7 7. Keowee Hydro Station has several methods of communication. There are in station page phones and
7 telephones connected to Oconee. There is an automatic ring down phone to Oconee Unit 2 Control
7 Room. There are portable radios for Operators and Security.

9.5.1.5 Fire Detection and Suppression

9.5.1.5.1 Fire Detection

1. Deviations from NFPA 72D are identified and justified by paragraph number per National Fire Code,
7 1976:

2

1221, 1223 - At Oconee, the alarm comes into the control room. The operator then notifies plant personnel of the fire location.

1231 - Alarms on the control board are tested on each 12-hour shift by operator procedures.

1232 - Procedures require annual testing of transmitters and water flow actuated devices. Water spray systems for safety-related equipment are tested on an annual basis.

2110 - The Oconee fire detection system is cabled using steel/aluminum sheathed #16 AWG cable for signal transmission. This cable meets or exceeds the requirements for physical and electrical protection as defined in NEC, Article 760.

2222, 2223 - The fire detection system at Oconee is powered from a battery backed power supply through a static inverter to provide 240/120 VAC. These batteries which are Class 1E but utilized as Non-Class 1E are continuously charged from normal station power. On loss of normal station power, the system is designed to provide power to the fire detection system for one hour. In addition, a transfer switch is provided for transferring the inverter loads to regulated normal station AC power should a malfunction of the battery inverter supply occur.

2521 - The annunciator audible alert at Oconee serves the fire detection system as well as other plant systems. The visual indicator provided by the visual display prevents operator confusion regarding source of the alarm.

2. The fire detection system provides an audible and visual alarm and annunciation in the control room. Local audible alarms do not sound at the location of the fire. The operator receives the alarm in the control room, dispatches plant personnel to the location of the alarm to ascertain the local conditions and then, if necessary, summons the fire brigade by the PA and a radio paging system. By using the PA system the chance of misinterpretation of the alarm is minimized.

3. As stated in (2) above, with the use of the PA system, the possibility of confusion of the fire alarm with any other plant system alarms is negligible.

4. The fire detection system is powered from a battery-backed power supply through a static inverter to provide 240/120 VAC.

   These batteries which are Class 1E, but utilized as Non-Class 1E are continuously charged from normal station power. If normal station power is lost the system is designed to provide power to the detection system for one hour. In addition, a transfer switch is provided for transferring the inverter loads to regulated normal station AC power should a malfunction of the battery/inverter supply occur. This system design provides a power supply as dependable as the emergency power sources.

   Locations of detection devices are shown in Table 9-12. Detector locations in Equipment Rooms, Battery Rooms, Penetration Rooms and other areas exceed recommended spacing; however, spacing is in accordance with NRC commitments. Detector locations are selected based on engineering judgement to monitor areas containing vital equipment.

7 5. Keowee Hydro Station Fire Detection provides an audible and visual alarm and annunciation in the
7 Control Room. The Oconee Nuclear Station Fire Brigade is utilized at Keowee. The Detection
7 System is powered normally by regulated AC Power. The station batteries provide power should AC
7 Power be lost. Locations of detection devices are shown in Table 9-12.

9.5.1.5.2 Fire Protection Water Supply Systems

1. An underground fire loop (16 inch cement-lined, ductile iron pipe) is provided around the perimeter of the plant site. Post indicator valves are provided and are sealed or locked open to prevent inadvertent closing of valves required open for fire protection. Monthly recorded inspections of fire protection valves and key control procedures will back up the availability of water for fire protection. Post indicator valves are arranged to provide isolation to portions of the main for maintenance or repair without shutting off the complete system.

   Valves will allow other service water systems to be removed from the HPSW system without compromising the fire protection system.

2. As indicated above, a 16 inch loop is provided around the perimeter of the plant. Connections from this header to the units are redundant. Auxiliary Building headers are fed from a 16 inch line coming from the yard and a four inch line from the Turbine Building.

3. Two 6000 gal/min and one 500 gal/min (jockey) high pressure service water pumps supply the HPSW system.

   The 500 gal/min pump will normally operate to keep pressure on the fire headers. In the event of a fire, one full size pump provides adequate capacity for fire protection service. The second full size pump is considered to be a spare.

   A 100,000 gallon elevated storage tank is provided as described in Section 9.5.1.2, "System Description and Evaluation."

   Each pump has a motor with power taken from separate sources, i.e.: HPSW Pump A power from Bus No. 2, Unit No. 1; HPSW Pump B power from Bus No. 1, Unit No. 1.

   Since both HPSW pumps are powered directly from the 4160 V Buses which are interconnected between Oconee 1, 2 and 3 and to the emergency power from Keowee Hydro, adequate backup power is provided.

   The HPSW pumps are located in separate concrete block structures with power cable to the motors being embedded in concrete floor. Separation is by fire rated wall assemblies.

   HPSW system alarms received in the Control Room are:

   - Jockey pump stopped
   - Low HPSW system header pressure
   - Low elevated water storage tank level
   - Elevated water storage tank overflow.

4. Water is supplied to the HPSW pumps from the CCW system piping. Intake for this water is through the twelve pumps located at the intake structure. If power is lost to the CCW pumps, the
   3 system can continue to function as an unassisted syphon.

   Intake for the HPSW pumps is located at the CCW cross-connect header in Oconee 1 for HPSW pump A and Oconee 2 for HPSW pump B and the jockey pump. The CCW headers can be connected between Oconee 1, 2 and 3 to allow flow from either or all units as required.

   A 100,000 gallon elevated water storage tank has inventory which is also available to provide water for fire protection.

5. The total water supply using one 6000 gal/min pump for two hours is 720,000 gallons.

   The greatest demand for fire protection water is based on 1000 gal/min for fire hose plus 2571 gal/min (all sprinkler heads opened and flowing in the Unit 3 Turbine Building Mezzanine Level Sprinkler System) plus 500 gal/min non-fire related service water for a total of 4071 gal/min. This demand is

4 not a Selected Licensee Commitment. The largest Selected Licensee Commitment demand is 1738 gal/min. required by the Unit 3 Cable Room Water Spray System. This demand includes a 1238
0 gal/min system demand plus a 500 gal/min. non-fire related service water demand. A hose stream allowance is not included for this system based upon its expected usage.

6. Water for the fire protection system is provided from Lake Keowee. Full pond elevation is 800+0 with maximum drawdown at elevation 775+0.

   Between elevation 800+0 (full pond) and elevation 775+0 (maximum drawdown) there are 391,679 acre-feet of water available.

7. Fire hydrants are installed at a maximum of every 300 feet. Hose supplies are adequate to provide fire protection to all perimeter areas. Post indicator valves are provided and sections of the fire loop can be isolated for maintenance or repairs. Hose houses are located at several yard hydrants and are equipped with at least 200 feet of 1½ inch hose, 200 feet of 2½ inch hose, one-2½ inch gated wye and two-1½ inch nozzles and one-2½ inch to 1½ inch reducer.

7 8. Keowee Hydro Station has an independent fire protection service water pump. The pump takes
7 suction from the west wing wall of the spillway on Lake Keowee. This pump is provided for hose
7 stations on the operating floor, the Main Transformer Spray System, and the Yard Hydrants.

9.5.1.5.3 Water Sprinklers and Hose Standpipe Systems

1. Each automatic sprinkler system and hose station header has an independent connection to the plant HPSW System. LPSW System supplies the source water for hose stations in the Reactor Building.
7 Hose stations at Keowee are supplied by the SW System.

7 2. Valves for the HPSW and SW System are not electrically supervised. A program at the station requires fire protection valves to be sealed or locked in the normal open position. A periodic recorded inspection is conducted to ensure that there has been no tampering with the fire protection valves.

3. The automatic sprinkler systems were designed to conform to requirements of appropriate NFPA Standards.

4. Hose stations installations are equipped with a maximum of 100 feet of 1½ inch fire hose with an adjustable nozzle.

   Hose stations are located on elevations 771 + 0, 783 + 9 and 809 + 3 in the Auxiliary Building, and on all three levels in the Turbine Building. Six hose stations are located in each Reactor Building.
7 The LPSW System supplies the source water in the Reactor Building. Hose stations are located
7 throughout Keowee Hydro Station.

5. Adjustable nozzles are provided on hoses for fighting fires. These nozzles are appropriate for the type fires which might occur.

8 6. The only fire suppression system at Oconee which uses foam is located in the Radwaste Facility. This
8 fire suppression foam system, which has been abandoned because the process and material have been
8 abandoned, would have protected from fires around the Polymer used in the solidification system.

9.5.1.5.4 Halon Suppression System

The Administration Building Record Storage Vault is protected by a Halon 1301 total flood fire suppression system.

9.5.1.5.5 Carbon Dioxide Suppression System

7 1. The SSF Diesel Generator Room is protected by a low pressure total flooding carbon dioxide
7 suppression system.

7 2. The Keowee generators are protected by a High Pressure Carbon Dioxide Suppression System. This
7 system provides carbon dioxide to the generator housing only.

9.5.1.5.6 Portable Extinguishers

4 Portable fire extinguishers are provided in accordance with NFPA 10, "Standard For Portable Fire
4 Extinguishers."

9.5.1.6 Guidelines for Specific Plant Areas

9.5.1.6.1 Primary and Secondary Containment

1. The Reactor Coolant Pumps, which are not required to operate but must maintain pressure boundaries for safe shutdown, have been provided with seismically qualified oil collection systems to prevent oil spillage reaching areas which may be above the flash point of the lubricating oil. The upper and lower oil pots have been modified with a shield to catch oil and carry it through a properly sized drain to a collection tank.

   Station procedures assure that during a refueling outage the oil collection system will be subjected to a routine preventative maintenance program and the collection tank will be verified to be empty prior to unit startup.

   The cable used at Oconee is constructed such that internal faults will not be a source of ignition.

   Carbon filters are treated as described in Section 9.5.1.4.4, "Ventilation" (d). Portable extinguishers are available in the area in case a fire should start.

2. During refueling and maintenance periods, an excess of materials and personnel are in areas which are normally clear (i.e., work areas outside personnel hatches). During these periods, security personnel are on duty 24 hours at the personnel hatch entrance and are in a position to observe maintenance activities. These areas are protected by an automatic sprinkler system.

7 Nuclear System Directives require permits for any welding and cutting operations and ensure that
7 proper precautions are taken prior to allowing work to begin.

   Portable fire extinguishers are provided within the containment. In the event of a fire, fire brigade personnel would bring additional fire extinguishers to the area for fire fighting.

   Self-contained Breathing Apparatus are provided for the fire brigade personnel and additional air supply is available on site as previously described.

9.5.1.6.2 Control Room

The control room is isolated from other areas of the plant by three hour fire barriers except for the wall adjacent to the lobby around the entrance door, where a steel plate was provided to satisfy concerns other than fire protection. Since the lobby is free of combustible material (and transient combustibles are not expected to obstruct the door), a fire would not propagate into the Control Room via the steel plate. There are two doors to stairways with 1½ hour rated doors which were found to be acceptable based on low combustible loading and constant attendance of the Control Room.

Fire hazard evaluations indicated that a fixed extinguishing system is not required in the Control Rooms, however, smoke detection devices have been located inside cabinets and consoles. Hose stations are located adjacent to each control room area with portable extinguishers provided in and around the general area. Guidance has been provided for the fire brigade concerning use of water in the control room.

Nozzles used on the hose stations in the area are the adjustable type which would cope with actual fire fighting needs, satisfy electrical safety and minimize physical damage to electrical equipment from hose stream impingement.

As previously stated, smoke detection is provided in the control room. The ionization detectors alarm on the control panel along with alarms from other areas of the plant. In addition to adding detectors in the cabinets and consoles, the location of several detectors have been modified in accordance with applicable NFPA Standard to provide effective coverage.

Breathing apparatus for control room operators is provided for each control room. Two self-contained Breathing Apparatus units are provided in each complex with additional air supply available as described in Section 9.5.1.4.4, "Ventilation" (8).

7 Power and control cables are not located in the concealed floor and ceiling space and cables entering the
8 control room terminate there, except for the miscellaneous computer room equipment and as stated in
8 Section 9.5.1.4.3, "Electric Cable Construction, Cable Tray and Cable Penetrations"/010.

9.5.1.6.3 Cable Spreading Room

The cable rooms at Oconee have ionization detectors and portable extinguishers available.

Manual hose stations are located adjacent to the cable rooms, which would be used in the event of a cable room fire. Portable extinguishers are also provided.

Cable rooms are separated from other plant areas by fire rated barriers and have at least two remote and separate entrances to provide access by fire brigade personnel.

The Cable Rooms and adjacent Cable Shafts are protected with manually actuated fixed water spray systems, hydraulically designed to provide a density of 0.10 GPM per square foot. The design of each Cable Room water spray system requires the manual operation of a HPSW full size pump to provide the above spray density.

9.5.1.6.4 Plant Computer Room

Each control room has a computer room adjoining it. These computers are not control computers and perform no safety functions.

9.5.1.6.5 Switchgear Rooms

Equipment rooms at Oconee are separated from other plant areas by adequate barriers. Automatic fire detection alarms and annunciates in the control room. Fire hose stations and portable extinguishers are readily available. Switchgear for equipment is located in the Turbine Building at Elevation 796 + 6.

The Equipment Rooms and adjacent Cable Shafts are protected by manually actuated fixed water spray systems, hydraulically designed to provide a density of 0.10 GPM/square foot. The design of each Equipment Room water spray system requires the manual operation of a HPSW full size pump to provide the above spray density.

9.5.1.6.6 Remote Safety Related Panels

Combustible materials except cabling associated with the panels are not located in the area of the remote shutdown panels. Hose stations and portable extinguishers are available.

9.5.1.6.7 Station Battery Rooms

Battery rooms are separated from the Turbine Building by three hour fire rated walls. Ventilation systems in the battery rooms are designed to maintain the hydrogen concentration below two percent volume concentration. Portable fire extinguishers are provided in each battery room in addition to extra extinguishers in adjacent areas.

9.5.1.6.8 Turbine Lubrication and Control Oil Storage and Use Area

The main turbine oil tanks are located on the Mezzanine Floor (Elevation 796+6). Each tank and distribution system is protected by an ionization detector and an automatic deluge sprinkler system.

The Turbine/Auxiliary Building wall is constructed of three hour fire rated materials except where flood control measures are required at door openings in the basement of the Turbine Building and mechanical penetrations within fifty feet from safety related cable trains.

9.5.1.6.9 Diesel Generator Area

7 As stated in Section 9.5.1.5.5, "Carbon Dioxide Suppression System," the Diesel Generator located in the SSF is protected by a total flooding carbon dioxide system.

7

9.5.1.6.10 Diesel Fuel Oil Storage Areas

The bulk Diesel Fuel Oil Storage tank is buried. A smaller volume day tank is located in the SSF and is protected by the total flooding carbon dioxide system.

9.5.1.6.11 Safety Related Pumps

1. High Pressure Injection Pumps: Located in the Auxiliary Building at Elevation 758+0. One pump is separated from the others by masonry walls.
2. Low Pressure Injection Pumps: See (1) above.
3. Low Pressure Service Water Pumps: Located in the Turbine Building at Elevation 775+0.
4. Turbine Driven Emergency Feedwater Pump: Located in the Turbine Building at Elevation 775+0. Detection which alarms and annunciates in the control room is provided in addition to an automatic water spray system.
5. Motor Driven Emergency Feedwater Pumps: Located in the Turbine Building at elevation 775+0.

9.5.1.6.12 New Fuel Area

At the present time new fuel is put into the spent fuel pool prior to installation in the reactor. No specific area has been designated as new fuel area. The spent fuel pool area is protected by portable extinguishers.

9.5.1.6.13 Spent Fuel Pool Area

See Section 9.5.1.6.12, "New Fuel Area."

9.5.1.6.14 Interim Radwaste Building

At Oconee, the Interim Radwaste Building is a separate building. Fire hydrants and portable extinguishers are located in and around the Interim Radwaste Building. A radwaste technician conducts routine tours whenever the Interim Radwaste Building is being utilized.

9.5.1.6.15 Decontamination Area

Flammable liquids are not stored in the Decontamination Area.

9.5.1.6.16 Safety Related Water Tanks

Storage tanks supplying water for safe shutdown are located in areas which contain a minimum of combustibles or located outside the building. Portable extinguishers are provided in the area.

9.5.1.6.17 Cooling Towers

Not applicable to Oconee Nuclear Station.

9.5.1.6.18 Miscellaneous Areas

Records storage areas, shops, warehouses and auxiliary boilers are located such that if a fire occurs in this area it will not affect safe shutdown. The fuel oil tanks for the auxiliary boiler are located outside the protected area and are provided with appropriately sized dikes.

9.5.1.6.19 Radwaste Facility

9 The Radwaste Facility is provided with several fire protection features such as suppression systems,
9 detection systems, etc. The following is a short description of the feature and whether or not it is
9 considered to be in service;

9 • The Polymer Fill Station is provided with an overhead automatic foam-water spray system, but this
9 system has been permanently removed from service because the polymer process is not in service.
9 • The trash storage and shredder area, truck bay, over contaminated oil pump skid, decontamination
9 skid, and contaminated oil storage area are provided with an automatic suppression system because of
9 the potential for transient combustibles.
9 • The Polymer tanks are vented through the roof with a flame arrestor on the discharge.
9 • Smoke detectors are located over hazards and in some of the HVAC ductwork in the facility. These
9 detectors alarm in the Radwaste Facility and then send a remote single point alarm to the Unit 3
9 Control Room.
9 • Vapor detectors are located in polymer fill station and near the tank fill line in the truck bay where
9 vapors may accumulate.
9 • Portable fire extinguishers and fire hose stations are provided throughout the facility.
9 • There are 3 charcoal filter units located on elevation 819′ which have manual operated deluge systems;
9 • Filter TVF-1, which is in service, has a local fire detector in its housing that alarms directly to the
9 Radwaste Control Room.
9 • Filters F-1A and F-1B are located in the same room however they are separated by a concrete
9 wall, protecting each other from an exposure fire. These filter trains are not in service because the
9 Aerojet System is not in service. These filters used high outlet temperature detectors and a
9 downstream HVAC duct detector to determine if there was a problem present.

7 **9.5.1.6.20 Keowee Hydro Station**

7 Emergency Power for Oconee is the Keowee Hydro Station. Keowee is a two-unit hydro plant with a
7 combined rated output of 175,000 KVA, which is connected to Oconee's 230 KV Switching Station
7 through a single circuit overhead transmission line, and to the Oconee Main Feeder Buses through a
7 single 13.8 KV underground line.

7 The Main Transformer and Lube Oil Storage Room at Keowee are protected by Automatic Deluge
7 (Spray) Systems. The station is equipped with detection which alarms and annunciates in the Keowee
7 and Oconee Control Rooms.

7 The Fire Protection Pump provides pressure for the Main Transformer Deluge System, as well as hose
7 stations on the operating floor and yard hydrants. Other hose stations and Deluge systems have sufficient
7 operating head due to the suction piping source elevation.

7 In addition to hose stations throughout the plant, fire extinguishers are also provided thoughout the plant.

7 **9.5.1.6.21 Essential Siphon Vacuum Building**

7 Two hose stations are provided in this building. There is a minimum amount of combustibles in the
7 building. Six (6) fire detectors are provided in the building which annunciate to Unit 3 Control Room
7 Fire alarm panel.

9.5.1.7 Special Protection Guidelines

9.5.1.7.1 Welding and Cutting, Acetylene - Oxygen Fuel Gas Systems

Stations procedures cover storage and use of this equipment. A permit system is required to utilize this equipment.

9.5.1.7.2 Storage Areas for Dry Ion Exchange Resins

Dry Ion exchange resins are not stored near vital areas. Resin storage in other areas is maintained at the minimum practical.

9.5.1.7.3 Hazardous Chemicals

A program has been implemented concerning the storage and use of hazardous chemicals at Oconee Nuclear Station.

9.5.1.7.4 Materials Containing Radioactivity

Materials are stored in accordance with station documents.

2 9.5.2 INSTRUMENT AND BREATHING AIR SYSTEMS

2 9.5.2.1 Design Basis

2 The Instrument and Breathing Air Systems are designed to provide clean, dry, oil free instrument air to all
7 air operated instrumentation and valves. Instrument air is supplied to ANSI/ISA-S7.3-1975 (R1981)
7 standards, and breathing air is supplied at ANSI Z86.1 Grade D standards to minimize personnel
2 exposure in areas of airborne contamination.

2 9.5.2.2 System Description

2 The Instrument Air (IA) System consists of a) one primary IA compressor with two filter/dryer trains, b)
2 three backup IA compressors with two filter/dryer trains, c) distribution headers, d) receiver tanks and e)
2 components supply lines. The IA System is shared by all three Oconee Units; therefore, the IA System is
2 required to operate continuously.

2 Normal operation for the IA System is for the primary IA compressor to supply all IA demands. Should
2 the primary IA compressor trip, be required to be removed from service for maintenance, or the IA
2 System demand exceed the primary IA compressor capacity, the backup IA compressors and any available
2 Service Air System compressor capacity reserves are used in supplying IA System demands.

7 An Auxiliary Instrument Air (AIA) System provides a backup auxiliary source of instrument air to key
7 plant components in order to minimize operator burden during a normal loss of IA event while reaching
7 and maintaining a safe shutdown. This system is composed of three (one per unit) compressors,
7 combination filters, and desiccant dryers. Separate distribution headers and supply lines are provided to
7 these key components to ensure AIA availability. The AIA System is designed such that a failure will not
7 fail Instrument Air or affect operating equipment.

7 Although the AIA System may be available, it is not required for performing or supporting any operation.
7 Each of the key plant components supplied backup AIA fails in a safe condition and has an alternate
7 procedurally controlled method to control the process.

6 The Unit 1 and 2 Breathing Air System and the Unit 3 Breathing Air System each consist of one primary
6 and one backup compressor package. These packages consist of one a) two stage inlet air filter, b)
2 compressor, c) air/oil separator, d) and oil cooler/aftercooler. After the compressor the air is passed
6 through a) an air/water separator, b) a filter package, c) two purification packages in parallel (Unit 3 'A'
6 train has only one purifier package), d) into two parallel receiver tanks, and e) finally into the breathing air
2 manifolds. Breathing air is supplied to all areas and elevations by headers and individual supply stations
2 where the pressure is regulated for personnel use. Units 1 & 2 have one primary and one backup
2 compressor total for both Units, and Unit 3 has one primary and one backup for its use. The breathing
2 air systems are cross connected in such a way that any of the compressors can supply either of the Units'
2 breathing air needs.

9.6 STANDBY SHUTDOWN FACILITY

9.6.1 GENERAL DESCRIPTION

2 The Standby Shutdown Facility (SSF) is designed as a standby system for use under extreme emergency
2 conditions. The system provides additional "defense in-depth" protection for the health and safety of the
2 public by serving as a backup to existing safety systems. The SSF is provided as an alternate means to
8 achieve and maintain mode 3 with an average Reactor Coolant temperature ≥ 525°F (RCS cold leg
8 temperature ≤ 555°F and RCS pressure ≃ 2155 psig) following postulated fire, sabotage, or flooding
2 events, and is designed in accordance with criteria associated with these events. Loss of all other station
7 power does not impact the SSF's capability to mitigate each event. The SSF is also credited as the
7 alternate AC (AAC) power source and the source of decay heat removal required to demonstrate safe
7 shutdown during the required station blackout coping duration. In that the SSF is a backup to existing
2 safety systems, the single failure criterion is not required. However, failures in the SSF systems will not
2 cause failures or inadvertent operations in existing plant systems. The SSF requires manual activation and
2 would be activated under adverse fire, flooding or sabotage conditions when existing redundant emergency
2 systems are not available.

2 The SSF is designed to:

2 1. Maintain a minimum water level above the reactor core, with an intact Reactor Coolant System, and
2 maintain Reactor Coolant Pump Seal cooling.
2 2. Assure natural circulation and core cooling by maintaining the primary coolant system filled to a
2 sufficient level in the pressurizer while maintaining sufficient secondary side cooling water.
2 3. Transfer decay heat from the fuel to an ultimate heat sink.
7 4. Maintain the reactor subcritical, after all normal sources of RCS makeup have become unavailable, by
7 providing makeup via the Reactor Coolant Makeup Pump System which always supplies makeup of
7 a sufficient boron concentration.

2 The SSF consists of the following:

2 1. SSF Structure
2 2. SSF Reactor Coolant Makeup (RCM) System
2 3. SSF Auxiliary Service Water (ASW) System
2 4. SSF Electrical Power
2 5. SSF Support Systems

2 System Main Components are listed in Table 9-14. SSF Primary Valves are listed in Table 9-15. SSF
2 Instrumentation is listed in Table 9-16.

2
9.6.2 DESIGN BASES

2 **FIRE PROTECTION CRITERIA**

8 Cabling for the two independent methods to achieve mode 3 with an average Reactor Coolant
8 temperature ≥ 525°F, the SSF, and the normal plant safety systems, are separated to the extent practical
2 within containment and by three-hour fire barriers outside containment.

8 The following additional criteria were utilized for identifying problem areas and to design the necessary
2 system changes to insure safe shutdown.

2 1. The hypothesized fire is to be considered an "event", and thus need not be postulated concurrent with
2 non-fire-related failures in safety systems, other plant accidents, or the most severe natural
2 phenomena.
2 2. Cold shutdown must be achievable within seventy-two hours following the fire accident. Credit can
2 be taken for reasonable damage control measures.
2 3. No credit is allowed for fire protection equipment in developing shutdown scenarios.

2 **TURBINE BUILDING FLOOD CRITERIA**

8 Components of the SSF systems and the associated structures are designed to achieve and maintain mode
8 3 with an average Reactor Coolant temperature ≥ 525°F (RCS cold leg temperature ≤ 555°F and RCS
8 pressure ≃ 2155 psig) in the event the Turbine Building is subjected to internal flooding.

7 The turbine building flood began as an event which was not considered to occur with any other plant
7 events (i.e. seismic). The NRC reviewed and approved the design of the SSF to mitigate fire, turbine
7 building flood, and sabotage.

7 During the seismic qualification review of the Oconee EFW system in the 1980s, the turbine building
7 flood event was redefined as being the result of a seismic event. It was concluded that the EFW system
7 would not be available following a maximum hypothetical earthquake since the turbine building would be
7 flooded and the EFW pumps would be inundated with water and considered unavailable. As a result, the
7 NRC reviewed the Oconee design to determine if adequate decay heat removal would be available
7 following the maximum hypothetical earthquake and a concurrent single active failure. The requirement
7 for a concurrent single active failure was viewed as a potential backfit issue. The NRC reviewed the need
7 to require the SSF to be single failure proof and determined that additional modifications to the SSF were
7 not warranted. The NRC determined that additional modifications were not warranted based on the
7 availability of HPI feed and bleed as an alternate means of decay heat removal. With the combination of
7 HPI feed and bleed and the SSF auxiliary service water system, the NRC closed the issue concerning the
7 concurrent single active failure.

7 Since the SSF was not backfitted to be single failure proof, the initial licensing requirements of crediting
7 the SSF for mitigation of a turbine building flood were not changed. The availability of HPI feed and
7 bleed was credited in the backfit analysis but is not credited in the Oconee licensing basis for mitigation of
7 the turbine building flood. However, HPI feed and bleed does play an important role in the reduction of
7 the core melt frequency for a turbine building flood event and is described in the safety analysis report as
7 an alternate means of decay heat removal. Thus, changes to HPI feed and bleed should be evaluated for
7 their impact on the consequences of a turbine building flood event.

7 In addition to HPI feed and bleed, Duke indicated on a number of occasions that the Station auxiliary
7 service water system was an alternate means of decay heat removal. Duke did not credit the Station
7 auxiliary service water system in the mitigation of the turbine building flood. In addition, the NRC did
7 not credit the Station auxiliary service water system for the mitigation of the turbine building flood event
7 in the licensing basis or backfit analysis.

7 The reactor building spray pumps are described with respect to the waterproofing of the walls between the
7 auxiliary building and the turbine building. However, Duke did not credit the reactor building spray
7 pumps in the mitigation of the turbine building flood. In addition, the NRC did not credit the reactor
7 building spray pumps for the mitigation of the turbine building flood event in the licensing basis or backfit
7 analysis.

2 **ELECTRICAL SEPARATION CRITERIA**

7 Selected motor operated valves and a pressurizer heater bank are capable of being powered and controlled
2 from either the normal station electrical systems or the SSF electrical system. Suitable electrical
2 separation is provided in the following manner. Electrical distribution of the SSF is identified in
2 Figure 9-40 and Figure 9-41 is provided by the SSF motor control centers (MCC's). These MCC's are
2 capable of being powered from either an existing plant load center or the SSF load center through key
2 interlocked breakers at the MCC's. These breakers provide separation of the power supplies to the SSF
2 loads.

2 During normal operation, these loads are powered from a normal (non-SSF) load center via the SSF
2 MCC's.

2 During operation of the SSF, these loads are powered from the SSF diesel generator via the SSF load
2 center and SSF MCC's.

2 9.6.3 SYSTEM DESCRIPTIONS

2 9.6.3.1 Structure

2 The Standby Shutdown Facility (SSF) is a reinforced concrete structure consisting of a diesel generator
2 room, electrical equipment room, mechanical pump room, control room, central alarm station (CAS),
2 and ventilation equipment room. The general arrangement of major equipment and structures is shown
2 in Figure 9-30, Figure 9-31, Figure 9-32, Figure 9-33 and Figure 9-34.

2 The SSF has a seismic classification of Category 1. The following load conditions are considered in the
2 analysis and design:

2 1. Structure Dead Loads
2 2. Equipment Loads
2 3. Live Loads
2 4. Normal Wind Loads
2 5. Seismic Loads
2 6. Tornado Wind Loads
2 7. Tornado Missile Loads
2 8. High Pressure Pipe Break Loads
3 9. Turbine Building Flooding Potential

2 **WIND AND TORNADO LOADS**

2 The design wind velocity for the SSF is 95 mph, at 30 ft. above the nominal ground elevation. This
2 velocity is the fastest wind with a recurrence interval of 100 years. A gust factor of unity is used for
2 determining wind forces. The design tornado used in calculating tornado loadings is in conformance with
2 Regulatory Guide 1.76 with the following exceptions:

2 1. Rotational wind speed is 300 mph.
2 2. Translational speed of tornado is 60 mph.
2 3. Radius of maximum rotational speed is 240 ft.
2 4. Tornado induced negative pressure differential is 3 psi, occurring in three seconds.

7 The spectrum and characteristics of tornado-generated missiles are covered later in this section.

2 **FLOOD DESIGN**

2 Flood studies show that Lake Keowee and Jocassee are designed with adequate margins to contain and
2 control floods. The first is a general flooding of the rivers and reservoirs in the area due to a rainfall in
2 excess of the Probable Maximum Precipitation (PMP). The FSAR addresses Oconee's location as on a
2 ridgeline 100′ above maximum known floods. Therefore, external flooding due to rainfall affecting rivers
2 and reservoirs is not a problem. The SSF is within the site boundary and, therefore, is not subject to
2 flooding from lake waters.

2 The grade level entrance of the SSF is 797.0 feet above mean sea level (msl). In the event of flooding due
2 to a break in the non-seismic condenser circulating water (CCW) system piping located in the Turbine
7 Building, the maximum expected water level within the site boundary is 796.5 ft. Since the maximum
2 expected water level is below the elevation of the grade level entrance to the SSF, the structure will not be
2 flooded by such an incident.

3

8 The SSF will stabilize the plant at mode 3 with an average Reactor Coolant temperature ≥ 525°F. As a
3 PRA enhancement the SSF is provided with a five foot external flood wall which is equipped with a water
3 tight door near the south entrance of the SSF. A stairway over the wall provides access to the north
3 entrance.

2 **MISSILE PROTECTION**

2 The only postulated missiles generated by natural phenomena are tornado generated missiles. The SSF is
2 designed to resist the effects of tornado generated missiles in combination with other loadings. Table 9-17
2 lists the postulated tornado generated missiles.

2 Penetration depths are calculated using the modified NDRC formula and the modified Petry formula.

9 Modified N.D.R.C Formula:

$$\text{Penetration depth, (x)} = \sqrt{4KNWd\left(\frac{v_o}{1{,}000d}\right)^{1.80}} \quad \text{for } x/d \leq 2.0$$

$$= \sqrt{\mathrm{KNWd}\left(\frac{v_o}{1{,}000\mathrm{d}}\right)^{1.80}} + \mathrm{d} \quad \text{for } \mathrm{x/d} > 2.0$$

9 Where:

9 N = missile shape factor = 0.72 for flat nosed bodies, 1.14 for sharp nosed bodies

9 K = concrete penetrability factor = $\frac{180}{\sqrt{f_c}}$

9 W = Weight in pounds

9 v_o = striking velocity

9 D = effective projectile diameter = $\sqrt{4A_c/\pi}$

9 A_c = projectile contact Area in in^2

9 Modified Petry Formula:

9 Penetration depth,(x) = $12K_pA_p \log_{10}(1 + V^2/215{,}000)$

9 Where:

9 K_p = a coefficient depending on the nature of the concrete

9 = 0.00426 for normal reinforced concrete

9 A_p = weight of missile per unit of impact area

9 = W/A_c

9 A_c = Impact Area

9 V = striking velocity of projectile

2 Table 9-18 lists the calculated penetration depths and the minimum barrier thicknesses to preclude
2 perforation and scabbing, hence eliminating secondary missiles.

2 **SEISMIC DESIGN**

2 The design response spectra correspond to the expected maximum bedrock acceleration of 0.1 g. The
2 design response spectra were developed in accordance with the procedures of Reg. Guide 1.60. The
2 seismic loads as a result of a base excitation are determined by a dynamic analysis. The dynamic analysis
2 is made utilizing the STRUDL-DYNAL computer program. The base of the structure is considered
2 fixed.

2 With the geometry and properties of the model defined, the model's influence coefficients (the flexibility
2 matrix) are determined. The contributions of flexure as well as shearing deformations are considered. The
2 resulting matrix is inverted to obtain the stiffness matrix, which is used together with the mass matrix to
2 obtain the eigenvalues and associated eigenvectors.

2 Having obtained the frequencies and mode shapes and employing the appropriate damping factors, the
2 spectral acceleration for each mode can be obtained from Design Ground Motion response spectra curves.
2 The standard response spectrum technique is used to determine inertial forces, shears, moments, and
2 displacements for each mode. The structural response is obtained by combining the modal contributions
2 of all the modes considered. The combined effect is represented by the square root of the sum of the
2 squares.

2 The analytical technique used to generate the response spectra at specified elevations is the time history
2 method. The acceleration time history of each elevation is retained for the generation of response spectra
2 reflecting the maximum acceleration of a single degree of freedom system for a range of frequencies at the
2 respective elevation. The structure will withstand the specified design conditions without impairment of
2 structural integrity or safety function.

2 9.6.3.2 Reactor Coolant Makeup (RCM) System

2 The SSF RCM System is designed to supply borated makeup to the Reactor Coolant System (RCS) to
2 provide Reactor Coolant Pump Seal cooling and RCS inventory. An SSF RCM Pump located in the
2 Reactor Building of each unit will supply makeup to the RCS should the normal makeup system and the
2 reactor coolant pumps become inoperative because of a station blackout condition caused by the loss of
2 all other on-site and off-site power. The system is designed to ensure that sufficient borated water is
8 available from the spent fuel pools to allow the SSF to maintain mode 3 with an average Reactor Coolant
8 temperature ≥ 525°F (the initiating event may cause average RCS temperature to drop below 525°F) for
2 all three units for approximately 72 hours. This time period is based on drawing the water level in the
2 spent fuel pool down to a minimum of one foot above the top of the spent fuel racks. The SSF RCM
5 System is operated and/or tested from the Standby Shutdown Facility. The SSF RCM System is shown
3 on Figure 9-35. The SSF RCM Pump is capable of delivering borated water from the Spent Fuel Pool

2 to the RC pump seal injection lines. A portion of this seal injection flow is used to makeup for RC
7 pump seal leakage while the remainder flows into the RCS to makeup for other RCS leakage.

2 The SSF RCM Pump is a positive displacement pump driven by an induction motor, powered from the
2 SSF Power System. The pump is located in the Reactor Building basement sufficiently below the spent
2 fuel pool water level to assure that adequate net positive suction head is available.

2 A SSF RCM Filter is supplied downstream of the SSF RCM Pump to collect particulate matter larger
2 than five microns that could be harmful to the seal faces. The filter is sized to accept three times the flow
2 output of the SSF RCM Pump. Fouling of this filter is not considered to be a problem since the filter
2 has been conservatively sized.

2 There is a select bank of pressurizer heaters that are normally controlled from the main unit's control
2 room, however, during SSF events this bank can be controlled should it become necessary from the SSF
2 Control Panel. Pressurizer level control can be accomplished from proper control of ASW flow to the
7 steam generators, and proper control of the SSF RC letdown line flow. Additional RCS inventory
3 control can be accomplished using the RV head vent. SSF D/G power can be connected to the RV head
7 vent valves. Control of the RV head vent valves will be accomplished using a portable control panel.

2 9.6.3.3 Auxiliary Service Water (ASW) System

2 The SSF ASW System is designed to cool the RCS during a station blackout and in conjunction with the
2 loss of the normal and Emergency Feedwater System by providing steam generator cooling.

2 The SSF ASW pump is the major component of the system. One motor driven SSF ASW pump,
2 powered from OST1 Switchgear, serves all three units and is located in the SSF. The suction supply for
7 the SSF ASW pump is lake water from the embedded Unit 2 condenser circulating water piping. A
7 portable submersible pump that can be installed in the intake canal and powered from the SSF is
7 available to replenish the water supply in the embedded CCW pipe if both forced CCW and siphon flow
7 through the CCW pipe is lost.

2 The SSF ASW flow rate provided to each unit's steam generators is controlled using the motor operated
4 valves on each unit's SSF ASW supply header. Manually operated bypass valves, installed in parallel with
4 the motor-operated valves, are also available to:

4 1. Provide SSF ASW Flow control at low SSF ASW Flow rates.

4 2. Provide more precise SSF ASW Flow control when used in parallel with the motor-operated valves.

2 The SSF ASW pump is sized to provide enough flow to all 3 Oconee units to adequately remove decay
2 heat from the RCS and maintain natural circulation in the RCS. An SSF ASW pump minimum flow
2 line is provided to ensure that the pump minimum flow requirements are met. The SSF ASW system,
2 pump and valves are operated and tested from the SSF only. The SSF ASW system is shown on
2 Figure 9-36.

2 Auxiliary service water enters the steam generators via the normal emergency feedwater ring headers.

2 9.6.3.4 Electrical Power

2 9.6.3.4.1 General Description

2 The Standby Shutdown Facility (SSF) Electrical Power System includes 4160VAC, 600VAC, 208VAC,
8 120VAC, and 125VDC power. This system supplies power necessary to maintain mode 3 with an average
8 Reactor Coolant temperature ≥ 525°F for the reactors of each unit, in the event of loss of power from all

2 other power systems. It consists of switchgear, load center, motor control centers, panelboards, batteries,
2 battery chargers, inverters, a diesel-electric generator unit, relays, control devices, and interconnecting cable
2 supplying the appropriate loads.

2 The 120VAC power system in conjunction with the 125VDC instrumentation and control power system
8 supplies continuous control power to all loads that are required for achieving mode 3 with an average
8 Reactor Coolant temperature ≥ 525°F of each reactor.

2 Following the loss of all normal and emergency power, on-site and off-site, the diesel-electric generating
2 unit will be manually started by initiating its start signal from the SSF Control Panel in the SSF. The
2 diesel generator and its associated auxiliaries are housed in a Class 1 structure and are protected against
2 seismic events.

2 The 4160VAC SSF Power System bus will then be connected to its diesel-electric, backup source of
2 power by manually closing the appropriate 4160VAC generator breaker.

2 Schematics of the SSF electrical system are shown on Figure 9-40 and Figure 9-41.

2 9.6.3.4.2 Diesel Generator

2 The SSF Power System is provided with standby power from a dedicated diesel generator. This SSF
2 diesel generator is rated for continuous operation at 3500 kW, 0.8 pf, and 4160 VAC. The SSF electrical
2 design load does not exceed the continuous rating of the diesel generator. The auxiliaries required to
2 assure proper operation of the SSF diesel generator are supplied entirely from the SSF Power System.
2 The SSF diesel generator is provided with manual start capability from the SSF only. It uses a
2 compressed air starting system with four air storage tanks. Each set of two tanks will provide sufficient air
7 to start the diesel unit three successive times. An independent fuel system, complete with a separate
2 underground storage tank, duplex filter arrangement, a fuel oil transfer pump, and one-hour day tank, is
2 supplied for the diesel-electric generating unit.

2 The diesel generator protection system initiates automatic and immediate protective action to prevent or
2 limit damage to the SSF diesel generator. The following protective trips are provided to protect the diesel
2 generator at all times and are not bypassed when the diesel generator is in the emergency mode:

2 1. Engine Overspeed
2 2. Generator Differential Protection
2 3. Low-low Lube Oil Pressure
9 4. Generator Overcurrent

2 9.6.3.5 Instrumentation

2 9.6.3.5.1 SSF Reactor Coolant Makeup System Instrumentation

2 Each unit is provided with instrumentation to monitor RCM System flow, pressure and temperature; RC
7 Loop A and B pressure and temperature; pressurizer level and pressure; and reactor incore temperature.
5 Five (5) Incore Thermocouples per unit may be used to monitor the incore temperature. Six (6) RTD's
5 per unit will be used to monitor Loop A and B RC System Hot & Cold Leg temperature. Readout is
2 displayed on the SSF control panel. Table 9-16 provides a listing of instrumentation.

2 9.6.3.5.2 SSF Auxiliary Service Water Instrumentation

2 Each unit is provided with Steam Generator A & B level instrumentation labeled as listed in Table 9-16.
6 Readout is displayed on the SSF control panel. Each unit's SSF ASW piping is also provided with

6 instruments to monitor SSF ASW System flow and pressure. Each unit's flow is displayed on the SSF
6 control panel. The SSF ASW pump recirculation piping is provided with instrumentation to monitor
6 SSF ASW System recirculation flow and pressure. The recirculation flow is displayed on the SSF control
6 panel.

2 9.6.3.6 Support Systems

2 The Standby Shutdown Facility (SSF) Support Systems are designed to provide for the SSF:

2 • Lighting
2 • Fire Protection
2 • Fire Detection
2 • Service Water
2 • Heating Ventilation and Air Conditioning (HVAC)
2 • Sump Drainage
7 • Potable Water

2 The diesel engine service water and the HVAC service water piping are designed in accordance with
2 ASME Section III, Class 3, which includes seismic design. The fire protection water, carbon dioxide,
2 potable water, and sewage piping systems are seismically restrained in areas above seismically designed
2 equipment. The lighting system, the fire detection system, and the sump drainage system, are not
2 seismically designed. The water and carbon dioxide fire protection systems and the fire detection system
2 are designed and constructed to meet or exceed National Fire Codes.

2 9.6.3.6.1 SSF Lighting System Description

2 Normal lighting for the SSF is provided by fluorescent and HID lighting units. These lighting units are
2 located to provide adequate levels of light with good distribution throughout the structure.

2 Emergency AC lighting for the SSF is provided by incandescent lighting units. These units are located to
2 provide adequate levels of lighting in all areas of the structure.

2 Emergency DC lighting for the SSF is provided by self-contained 12VDC battery pack lighting units.
2 These units are located to provide adequate levels of lighting for control panel operation and for entering
2 and leaving the structure. These battery pack lights are energized automatically upon an undervoltage in
2 the normal lighting system power supply.

2 9.6.3.6.2 SSF Fire Protection and Detection

2 The SSF contains two fire protection systems, a water system and a carbon dioxide system.

2 The water system is provided with manually valved hose reels in the stairwell at each floor elevation and
2 inside the entrance to the diesel room. From these locations the hose lengths are such that the entire SSF
2 can be served by the primary fire protection system.

2 The low pressure carbon dioxide system provided is actuated by thermal detectors to automatically flood
2 the diesel area. Carbon dioxide is stored in a refrigerated storage tank in sufficient quantity to provide
2 twice the required coverage for the area.

2 Portable carbon dioxide extinguishers are also provided.

2 Detection devices are located throughout the SSF and will annunciate with a single alarm to the Unit
2 Control Rooms, SSF Control Room, Security. Specific alarms annunciate on the Fire Alarm Control
2 Unit located in the SSF vestibule.

2 9.6.3.6.3 SSF Service Water

2 The SSF Service Water System consists of two subsystems: The HVAC Service Water System and the
2 Diesel Engine Service Water System.

2 The HVAC Service Water System, which operates continuously, contains two pumps and supplies
2 cooling water to the HVAC condensers. Only one pump will operate at any given time with the other
2 idle pump acting as a backup.

7 The Diesel Engine Service Water System, which normally operates only when the diesel is operating or
7 when system components are being tested, contains one pump and provides service water to the diesel
2 engine jacket water heat exchangers.

2 This flow is monitored during periodic operational test or emergency operation. All three pumps take
2 their suction from the embedded CCW piping and return the flow to the CCW piping after passing
2 through their respective system. SSF Diesel Service Water is diverted to the yard drain during an SSF
2 event to avoid overheating the water contained in the SSF ASW supply piping.

2 The SSF Diesel Service Water System is shown on Figure 9-37.

2 9.6.3.6.4 Heating Ventilation and Air Conditioning

2 The SSF HVAC system consists of two subsystems, a ventilation system and an air conditioning system.
2 Both systems are powered by the SSF Power System. Sections of each system are shut down in event of
2 fire in the area served.

2 VENTILATION SYSTEM

2 The diesel generator room, switchgear room, pump room, and HVAC room do not require close control
2 of temperature, and the relatively high heat loads are dissipated with a variable volume ventilation system.
2 The purpose of the ventilation system is to provide filtered outside air which is tempered if necessary to
7 maintain a minimum temperature of 60°F and a maximum temperature as follows:

7 • HVAC Room 120°F
7 • Switchgear Room 120°F
7 • Pump Room 120°F
7 • Diesel Generator Room 125°F

2 AIR CONDITIONING SYSTEM

2 Certain rooms in the SSF require close control of temperature and have year-round heat loads of such
2 magnitude to necessitate continuous operation of mechanical refrigeration to maintain 72°F and a
2 maximum of 50 percent RH with a minimum of outside air for ventilation. The air conditioning system
2 supplies each area with a constant volume of air. A heat coil located in each area with a local control
2 tempers the air as required to maintain the desired temperature.

2 **9.6.3.6.5 SSF Sump System**

2 The SSF Sump System provides a collection and discharge function for normal equipment drainage
2 within the SSF. The main components of the system are the sump and two sump pumps which handle
2 the flow routed to the sump via the floor drain system located throughout the SSF.

2 9.6.4 SYSTEM EVALUATIONS

2 9.6.4.1 General

2 The design of the SSF was reviewed to meet the requirements of Appendix R of 10CFR 50, Sections
2 III.G.3 and III.L, and those requirements applicable for flooding and seismic events.

2 The SSF, the associated mechanical and electrical systems and power supplies meet or exceed the
2 applicable criteria contained in the Oconee FSAR Chapter 3, "Design of Structures, Components,
2 Equipment, and Systems." Additionally, ASME and IEEE codes are utilized as appropriate, in the design
2 of various subsystems and components. The SSF and systems/components needed for safe shutdown are
2 designed to withstand the Safe Shutdown Earthquake (SSE). The SSF systems required for safe shutdown
8 are designed with adequate capacity to ensure safe mode 3 conditions with an average Reactor Coolant
8 temperature ≥ 525°F (the initiating event may cause average RCS temperature to drop below 525°F) of
2 all three Oconee units.

2 The SSF power system is designed with adequate capacity and capability to supply the necessary loads,
2 and is physically and electrically independent from the station electrical distribution system power supply.
2 Additionally, the AC and DC power systems and equipment required for the SSF essential functions have
5 been designed and installed consistent with the Oconee QA program of Class 1E equipment.

2 These systems are not designed to meet the single failure criterion, but are designed such that failures in
2 the systems do not cause failures or inadvertent operations of existing plant systems. The electrical
2 systems in the SSF are manually initiated, that is, multiple actions must be performed to provide flow to
2 existing plant safety systems.

2 9.6.4.2 Structure Design

2 The SSF is statically and dynamically analyzed and designed as a three-dimensional space frame subjected
2 to the applicable loads summarized in Section 9.6.3.1, "Structure." The Structural Design Language
2 (STRUDL) computer program is used to perform the analyses. The design is in accordance with the
2 codes and criteria listed in Table 9-19. Design loads and loading combinations are in accordance with the
2 NRC Standard Review Plan, Section 3.8.4.

2 The SSF is designed to withstand the effects of wind and tornado loadings, without loss of capability of
2 the systems to perform their safety functions. The basis for the selected wind velocity is reference 1 of
2 Section 3.3, "Wind and Tornado Loadings." Buildings and structures with a height to minimum
2 horizontal dimension ratio exceeding five should be dynamically analyzed to determine the effect of gust
2 factors (ref. American National Standard, "Building Code Requirements for Minimum Design Loads in
2 Buildings and Other Structures," ANSI A58.1-1972, New York, New York). The SSF has a height/width
2 ratio of less than five, and therefore, the gust factor of unity is used for determining wind forces. The
2 design tornado used in calculating tornado loadings is in conformance with Regulatory Guide 1.76 except
2 as noted in Section 9.6.3.1, "Structure."

2 The relatively small surface area of the structure and its location result in an extremely low probability
2 that a turbine missile would strike the facility. Turbine missile impact is not considered a viable load

2 condition due to the location of the SSF with respect to the turbine. All postulated missiles are per the
2 NRC Standard Review Plan Section 3.5.1.4 Rev. 1 and Regulatory Guide 1.76. The barrier thicknesses
2 for the structure are such that they preclude any perforation and/or scabbing from the postulated tornado
2 generated missiles. Minimum barrier thickness is three times the postulated missiles calculated depths of
2 penetrations (see Table 9-18).

2 The dynamic analysis is made utilizing the STRUDL-DYNAL computer program. The design response
2 spectra were developed in accordance with the procedures of Regulatory Guide 1.60. It corresponds to
2 the expected maximum bedrock acceleration of 0.1g. Damping values are per Regulatory Guide 1.61.

2 The structure will withstand the specified design conditions without impairment of structural integrity or
2 safety function.

2 9.6.4.3 Seismic Subsystem Analysis

2 The seismic analysis of Category I pipe is performed using dynamic modal analysis techniques. No static
2 seismic analysis is used for SSF ASME Code piping. Modal response spectrum methods are used.
2 Response of individual modes is combined by the Grouping Method of Regulatory Guide 1.92. An
2 adequate number of masses or degrees of freedom are included in the model to determine the response of
2 significant modes. The response due to each of three components of earthquake motion is combined by
2 the square-root-of-the-sum-of-the-square rule as described in Regulatory Guide 1.92. Pipe supported
2 from multiple levels or structure is designed for an envelop of the response spectra for all supporting
2 structures.

2 Constant vertical static factors are not used. Vertical response is obtained from a dynamic modal analysis.
2 Modal damping ratios are consistent with Regulatory Guide 1.61.

2 The location of the SSF non-Category I piping has been reviewed to determine those areas of proximity
2 to Category I piping or safety related equipment. Where Category I piping or safety related equipment is
2 in the proximity area, the non-Category I piping has been seismically qualified and supported or rerouted
2 out of the problem area.

2 The SSF auxiliary service water buried piping is seismically designed for stresses resulting from SSE and
2 OBE events. The design and analysis were based on the current state-of-the-art for initial effects and the
2 effects of static resistance of the surrounding soil.

2 9.6.4.4 Dynamic Testing and Analysis of Mechanical Components

2 Procedures were established for the startup testing of the Class B and C piping in the SSF to verify the
2 following information under different operating modes:

2 • Physical Compliance with Piping Design: An "as built" verification procedure is utilized to verify that
2 piping, components and support-/restraints have been erected with design tolerance.

2 • Vibration Monitoring for Equipment: The purpose of this monitoring program is to verify that
2 vibration levels for system components are within acceptance criteria. Pump vibration is monitored
2 during testing in accordance with IWP-3210 to verify vibrations are less than or equal to the
2 maximum allowable per the specific vendor's requirements.

2 9.6.4.5 ASME Code Class 1, 2, and 3 Components, Component Supports and Core
2 Support Structures

2 Piping systems for the SSF are designed in accordance with the appropriate ASME Code based on the

7 Quality Group classifications outlined in Regulatory Guide 1.26. Where part of an existing QA 1 piping
7 system was used by an SSF subsystem to perform its function, the existing piping system was not
7 "upgraded" to the pipe class and code used for piping when the SSF was constructed. The load
2 combinations and stress limits contained in the requirements of SRP 3.9.3.II and referenced in Regulatory
2 Guide 1.48 are met, except Code Case 1606 is used for the faulted load combination.

7 The SSF RC Makeup System is designed per the requirements stated in ASME Section III Class 2 (1974
7 Edition, Summer 1975 Addendum) to Oconee Class B. Portions of the HPI seal injection piping used by
7 the SSF RC Makeup System to deliver flow to the RC pump seals are designed to Duke Class C.

7 The SSF ASW System has a portion (crossover between emergency feedwater lines) in each Reactor
7 Building that was designed per the requirements stated in ASME Section III, Class 2 (1974 Edition,
7 Summer 1975 Addendum) to Oconee Class B. The remainder of the SSF ASW System was designed per
7 the requirements stated in ASME Section III Class 3 (1974 Edition, Summer 1975 Addendum) to Oconee
7 Class C. Portions of the EFW System piping used by the SSF ASW System to deliver flow to the steam
7 generators are designed to Duke Class F.

2 The loads from pressure relief valves with an open discharge are evaluated in accordance with Code 1569,
2 "Design of Piping for Pressure Relief Valve Station", assuming multiple valves on the same pipe open in
2 the most conservative sequence. A dynamic load factor of two is used to determine the transient loads
2 unless a lower value is justified by analysis.

2 Relief valves discharging into a closed system or a system with long discharge piping are reviewed to
2 identify any significant transient loadings. Any significant loading is analyzed using dynamic analyses to
2 include the effects of changes in momentum due to fluid flow changes of direction and any potential water
2 slugs. The piping will be adequately supported such that piping stresses associated with the defined
2 transient loads satisfy applicable Code requirements.

2 The loading combinations and stress limits contained in the requirements of SRP 3.9.3.II.4 and referenced
2 in Regulatory Guide 1.48 are met. However, ASME Code Section III Subsection NF did not provide
2 faulted condition allowable stress limits for Class 2 and 3 component supports until the 1977 edition. The
2 allowables for Class 1 components in the 1974 edition of Subsection NF and subsequent applicable
2 addenda for its Class 2 and 3 component supports faulted stress allowables were utilized.

2 9.6.4.6 Fire Protection

2 The SSF will be used when the existing plant systems or facilities of any of the three units are unavailable
8 due to a fire. The SSF is not designed to independently bring the reactor from mode 3 with an average
8 Reactor Coolant temperature ≥ 525°F to cold shutdown. Cold shutdown will be achieved and
2 maintained through the use of existing plant systems and equipment as discussed below. No repairs or
8 modifications are required to achieve mode 3 with an average Reactor Coolant temperature ≥ 525°F
2 utilizing the SSF shutdown method. Repairs for cold shutdown may be required depending upon the fire
2 area.

2 9.6.4.6.1 Safe Shutdown Systems

2 Safe shutdown of the reactor is initially performed by the insertion of control rods from the control room.
2 Insertion can also be accomplished by removing power to the control rod drive mechanisms. When
2 normal and emergency systems are not available, reactor coolant inventory and reactor shutdown margin
3 are maintained, from the SSF Control Panel, by the SSF RC makeup pump taking suction from the
2 spent fuel pool. Primary system pressure can be maintained by the pressurizer heaters or by use of
2 charging combined with letdown. Should the pressurizer heaters be unavailable (caused by fire inside
8 containment), progression towards cold shutdown may be initiated as soon as mode 3 with an average

8 Reactor Coolant temperature ≥ 525°F (RCS cold leg temperature ≤ 555°F and RCS pressure ≃ 2155
8 psig) is achieved. Decay heat removal may be accomplished by releasing steam from the steam generators
7 via the atmospheric main steam code safety valves. Makeup to the steam generators can be provided by
2 the Emergency Feedwater System. For fires affecting all banks of pressurizer heaters inside containment,
2 shutdown can be achieved from the unit's main control room.

2 Depressurization to cold shutdown can be achieved by bypassing steam to the turbine, use of the manual
2 atmospheric dump valves, or pressurizer spray. The low pressure injection (LPI) pumps will be used to
2 remove decay heat. Any damage to either the HPI or LPI power cabling or pump motors can be repaired
2 or replaced within 72 hours.

2 Also required for cold shutdown are the low pressure service water (LPSW) pumps. Only the one pump
2 for Unit 1 and 2 and one pump for Unit 3 is required for emergency plant operations. Five LPSW
2 pumps of equal capacity are provided - three for Units 1 and 2, and two for Unit 3. These pumps are
2 separated such that a single fire on any unit should not affect all pumps. The piping is separated such
2 that a single fire cannot affect all pumps. The piping for these pumps are interconnected so that they may
2 feed any of the three units. Any damage to the pump motors or associated power cabling can be repaired,
2 or if necessary, replaced within 72 hours.

2 **9.6.4.6.2 Performance Goals**

2 The performance goals for post-fire safe shutdown can be met using the SSF and undamaged/repaired
3 systems and equipment. Cold shutdown can be achieved within 72 hours of a fire by implementing
3 damage control measures including replacement of cables, pump motors, valve operators and use of
3 emergency switchgear. The control of these functions can be then accomplished using the SSF or the
2 control room, in the fire affected unit, depending on the location of the fire. The transfer of control
2 capability between the control room and the SSF is accomplished via a keyed interlock. Annunciation
2 will occur in the SSF control room upon transfer of control.

5 The process monitoring instruments to be used for a post fire shutdown include reactor coolant hot leg
5 and cold leg temperatures, reactor coolant pressure, pressurizer level and pressure, steam generator level,
5 SSF RC makeup pump flow, and SSF ASW system flow to each unit.

2 **STEAM GENERATOR PRESSURE**

8 Reactor coolant system (RCS) heat removal for achieving mode 3 with an average Reactor Coolant
8 temperature ≥ 525°F can be directly monitored by RCS parameters and controlled by SG level without
2 SG pressure indication, provided that SG pressure is regulated.

2 SG pressure should be regulated by the main steam code safety valves, which will relieve at their setpoints.
2 RCS conditions can be monitored by primary coolant temperature and pressure, pressurizer level and SG
2 level. Should RCS overcooling occur, corrective actions can be taken from the SSF to reinstate proper
5 cooling by controlling the SSF ASW flow rate provided to a unit's SGs in order to restore T-cold.

8 The SSF is designed to achieve and maintain mode 3 with an average Reactor Coolant temperature ≥
8 525°F (RCS cold leg temperature ≤ 555°F and RCS pressure ≃ 2155 psig) for one or more of the three
8 Oconee units. The SSF is not designed to independently bring the reactor from mode 3 with an average
8 Reactor Coolant temperature ≥ 525°F (RCS cold leg temperature ≤ 555°F and RCS pressure ≃ 2155
8 psig) to cold shutdown. Cold shutdown will be achieved and maintained through the use of normal plant
2 systems and equipment.

2 **SOURCE RANGE FLUX MONITOR**

8 The SSF is designed to achieve and maintain mode 3 with an average Reactor Coolant temperature ≥
8 525°F (RCS cold leg temperature ≤ 555°F and RCS pressure ≃ 2155 psig) for any or all of the Oconee
2 units. Prior to leaving the Unit 1/2 or Unit 3 control room, all control rods for the unit under
2 consideration are required to be inserted. No non-borated sources tie into the SSF makeup/boration flow
2 path. RCS makeup and boration following transfer of control to the SSF RCM is from the spent fuel
2 pool. Thus, boron dilution events are highly unlikely.

8 Oconee Units 1, 2, and 3 can achieve and maintain controlled cooling to mode 3 with an average Reactor
8 Coolant temperature ≥ 525°F (RCS cold leg temperature ≤ 555°F and RCS pressure ≃ 2155 psig) safely
5 from the SSF without the need for remote SG pressure instrumentation or a remote source range
5 monitor. Thus, this instrumentation for the Oconee Nuclear Station is not required. The objectives of
2 Sections III.G.3 and III.L.2 of Appendix R to 10CFR Part 50 are met and the exemption from the
2 requirement to provide remote steam generator pressure and source range monitor instrumentation in the
2 SSF has been granted.

2 **9.6.4.6.3 Instrumentation Guidelines**

2 10CFR 50, Appendix R Section III.L.6 requires that, "Shutdown systems installed to ensure post-fire
2 shutdown capability need not be designed to meet seismic Category I criteria, single failure criteria, or
2 other design basis accident criteria, except where required for other reasons, e.g., because of interface with
2 or impact on existing safety systems, or because of adverse valve actions due to fire damage." Since the
2 monitors for the above listed parameters, in Section 9.6.4.6.2, "Performance Goals," will not interface
2 with or impact on existing safety systems, the monitors need not be "safety grade".

2 **9.6.4.6.4 Repairs within the 72 Hour Requirement**

8 The use of the dedicated shutdown method for achieving mode 3 with an average Reactor Coolant
8 temperature ≥ 525°F permits the capability of achieving all necessary repairs to achieve cold shutdown
3 within 72 hours after a fire accident. Repairs, including replacement of power cabling, pump motors,
3 valve operators, and switchgear associated with LPI, HPI, or LPSW may be required for cold shutdown.
2 Stored on-site are all components necessary to achieve all repairs. Guidelines are available to implement
2 the required repairs and replacements.

2 **9.6.4.6.5 Fire Protection Conclusion**

2 The ONS design has provided one train of systems necessary to achieve and maintain safe shutdown
2 conditions by utilizing either the main unit's control room or the SSF in conjunction with undamaged
2 systems in the fire-affected unit, and thus will meet the requirements of Appendix R to 10CFR 50,
2 Sections III.G.3 and III.L with respect to safe shutdown in the event of a fire.

2 9.6.4.7 Flooding Review

2 The SSF will not be affected by the following postulated flood events:

2 1. Turbine Building Flood caused by a break in the non-seismic condenser circulating water (CCW)
2 piping system.
2 2. Infiltration of normal groundwater.

4

2 The structure meets the requirements of GDC 2, and the guidelines of Regulatory Guide 1.102 with
2 respect to protection against flooding.

2 ## 9.6.5 OPERATION AND TESTING

7 The SSF will be placed into operation to mitigate the consequences of the following events:

7 1. Flooding
7 2. Fire
7 3. Sabotage
7 4. Station Blackout

2 If the normal shutdown equipment is inoperable, operators will be sent to the SSF. When directed by the
2 shift supervisor, the operator will start the diesel and establish service water to the diesel generator, start
5 the Auxiliary Service Water Pump and the RCM system as needed and close all of the Reactor Building
2 isolation valves that are controlled from the SSF.

2 Damage control measures, if necessary, will be taken to restore limited operability to the Low Pressure
2 Injection System, Low Pressure Service Water System, and the HP Injection System to bring a RC
8 System to a cold shutdown condition following an Appendix R fire. Pump motors for each of the above
2 systems may be restored to an operable status and the valves will be manually operated to re-establish the
2 above systems to operation.

2 In-service testing of pumps and valves will be done in accordance with the provision of ASME Section XI
2 except for the Submersible Pump which is used to supply makeup water to the Unit 2 embedded
6 condenser circulating piping. This pump should be tested every other year to verify flow capability. A
6 recirculation flow path with flow and pressure instrumentation is available for SSF ASW pump testing.

2 The electrical power system components will be tested consistent with current accepted industry practice
2 for safety related equipment.

5 ## 9.6.6 REFERENCES

1. Safety Evaluation by the Office of Nuclear Reactor Regulation Oconee Nuclear Station Standby Shutdown Facility, Docket Nos. 50-269, 50-270, and 50-287, April 28, 1983
2. Safety Evaluation for Station Blackout (10 CFR 50.63) - Oconee Nuclear Station, Units 1, 2, and 3 (TACS M68574/M68575/M68576), Docket Nos. 50-269, 50-270, 50-287, March 10, 1992
3. Safety Evaluation for Station Blackout (10 CFR 50.63) - Oconee Nuclear Staton, Units 1, 2, and 3 (TACS M68574/M68575/M68576), Docket Nos. 50-269, 50-270, 50-287, December 3, 1992
4. Safety Evaluation Report on Effect of Tornado Missiles on Oconee Emergency Feedwater System (TACS 48225, 48226, and 48227), July 28, 1989
5. Safety Evaluation Report for Implementation of Recommendation for Auxiliary Feedwater Systems, August 25, 1981
6. Evaluation of the Oconee, Units 1,2,&3 Generic Safety Issues (GSI-23 & GSI-105) Resolution, March 24, 1995
7. Letter from WO Parker (Duke) to EG Case (NRC), dated 1/25/78, Response to NRC Questions
8. Letter from WO Parker (Duke) to EG Case (NRC), dated 2/1/78, SSF System Description
9. Letter from WO Parker (Duke) to EG Case (NRC), dated 6/19/78, Response to Staff Questions Concerning Oconee Nuclear Station Safe Shutdown System
10. Letter from WO Parker (Duke) to HR Denton (NRC), dated 3/28/80
11. Letter from WO Parker (Duke) to HR Denton (NRC), dated 2/16/81, Response to NRC Request for Information
12. Letter from WO Parker (Duke) to HR Denton (NRC), dated 3/18/81, Modifications Needed to Meet Appendix R Requirements
13. Letter from WO Parker (Duke) to HR Denton (NRC), dated 3/31/81, Response to NRC Request for Information
14. Letter from WO Parker (Duke) to HR Denton (NRC), dated 4/30/81, Cable Routing and Separation
15. Letter from WO Parker (Duke) to HR Denton (NRC), dated 1/25/82, Response to NRC Concerns for Source Range Instrumentation and Steam Generator Pressure
16. Letter from HB Tucker (Duke) to HR Denton (NRC), dated 9/20/82, Response to NRC Request for Information
17. Letter from HB Tucker (Duke) to HR Denton (NRC), dated 12/23/82, Requested Supplemental Information
18. Letter from HB Tucker (Duke) to HR Denton (NRC), dated 7/15/83, Request for Exemption from 10CFR50 Appendix R, Section III.L.2
19. Letter from JF Stolz (NRC) to HB Tucker (Duke), dated 8/31/83, Exemption from Source Range Flux and Steam Generator Pressure Instrumentation for the SSF

9 20. OSC-7350, Oconee Nuclear Station Penetration Seal Database and 86-10 Evaluations

9 21. DPS 1435.00-00-0002, Design Specification for Mechanical and Electrical Penetrations Fire, Flood,
9 and Pressure Seals

9 22. DPC 1435.00-00-0006, Calculation for the Technical Basis of Fire Barrier Penetration Seals

THIS IS THE LAST PAGE OF THE CHAPTER 9 TEXT PORTION.

4 **Table 9-10. Coolant Storage System Component Data (Component Quantities for Three Units)**

	Reactor Coolant Bleed Holdup Tank	
	Number	6
	Volume each, cu. ft.	11,000
	Material	Stainless Steel
	Design Pressure	Vessel Full Plus 10 ft. Hydro Head
	Deborating Demineralizer*	
	Number	5
8	Resin Volume, cu. ft	62.8
	Flow, gal/min	70
	Design Pressure, psig	150
	Concentrated Boric Acid Storage Tank	
	Number	3
	Volume each, cu. ft	3,000
	Material	Aluminum
	Design	Vessel Full Plus 10 ft. Hydro Head
	Quench Tank	
	Number	3
	Volume each, cu. ft.	780
4	Material	Stainless Steel
4	Design Pressure, psig	55
	Reactor Coolant Bleed Transfer Pump	
	Number	6
	Capacity each, gal/min	150
	Diff. Head, ft.	220
8	Concentrated Boric Acid Storage Tank Pump	
8	Number	3
9	Capacity each, gal/min	50
9	Type	Centrifugal
	Component Drain Pump	
	Number	3
	Capacity each, gal/min	100
	Diff. Head, ft.	100
	Coolant Bleed Evaporator Demineralizer	
	Number	2
	Resin Volume, cu. ft.	11
	Flow, gal/min	20
	Design Pressure, psig	150
	Condensate Demineralizer	
	Number	2
	Resin Volume, cu. ft.	2
	Flow, gal/min	20
	Design Pressure, psig	50
4		
	Coolant Bleed Evaporate Recirculating Pump	
	Number	1
	Capacity, gal/min	160
	Diff. Head, ft.	53
	Distillate Pump	
	Number	1
	Capacity, gal/min	7-12
	Diff. Head, ft.	60
	Coolant Bleed Evaporate Feed Pump	
	Number	1
	Capacity, gal/min	7½
	Diff. Head, ft.	60

Note:

* These demineralizers may be loaded with mixed bed and used as purification demineralizers to support normal purification and boron/lithium coordination programs.

Table 9-11. Ventilation System Major Component Data

	System	Equipment	Number Installed	Number Required Normal Operation
0 0				
0	Control Room Zone	Air Handling Unit*	2	1
0	Units 1 & 2	Air Handling Unit	1	1
0		Air Handling Unit	1	1
0		Air Handling Unit	2	2
0		Air Handling Unit	2	2
9		Booster Fan	2	0
9		Outside Air Filter Train	2	0
8 8		Cable Shaft Motorized Dampers	4	4
0				
0	Control Room Zone	Air Handling Unit*	2	1
0	Unit 3	Air Handling Unit	2	1
0		Air Handling Unit	2	1
9		Booster Fans	2	0
9		Outside Air Filter Train	2	0
0				
0 0	Auxiliary Building Units 1 & 2	Ventilation Unit** (Spent Fuel Pool)	1	1
0 0		Exhaust Fan (Spent Fuel Pool)	2	1
0		Ventilation Unit	1	1
0		Ventilation Unit	1	1
0		Ventilation Unit	1	1
0		Exhaust Fan	2	1
0		Exhaust Fan	2	1
0		Exhaust Fan	3	2
0				
0 0	Auxiliary Building Unit 3	Ventilation Unit** (Spent Fuel Pool)	1	1
0 0		Exhaust Fan (Spent Fuel Pool)	2	1
0		Ventilation Unit	2	1
0		Ventilation Unit	1	1
0		Exhaust Fans	3	2
0		Exhaust Fans	3	2
0				
0	Hot Machine Shop	Air Handling Unit***	1	1
0		Air Handling Unit	1	1
0		Booster Fan	2	2
0		Outside Air Filter Train	2	2
0				
0	Turbine Building	Roof Exhaust Fans	12	12
0		Exhaust Fans	18	18

Note:

* Air Handling Units consist of a fan, roughing filters, and chilled water coil.

**Ventilation Units consist of a fan, service water coil, and steam heating coil.

0 ***Air Handling Units consist of a fan, roughing filters and direct expansion (DX) coil.

2 **Table 9-14 (Page 2 of 3). SSF System Main Components**

5	Design Temperature (°F)	110
2	Design Flow Rate (gpm)	500
2	Design Head (ft)	90
2	Type	Centrifugal
2	Material of Construction	C. S.
2	Fluid	Strained River Water
2		
2	SSF Service Water Strainer	
2		
2	Quantity	1/Station
2	Design Pressure (psig)	50
9	Design Temperature (°F)	110
9	Design Flow Rate (gpm)	600
2	Mesh Size (inch)	0.1
2	Maximum Pressure Drop @ 65% Plugged (ft)	7
2	Type	Duplex
2	Material of Construction	C. S.
2		
2	SSF Sump Pump	
2		
	Quantity	2/Station
9	Nameplate Design Pressure (psig)	75
2	Design Temperature (°F)	100
2	Design Flow Rate (gpm)	100
9	Design Head from Pump Head Curve (ft)	44
2	Type	Centrifugal, Vertical Cantilever
2	Material of Construction	C. S.
2	Fluid	Floor Drain Liquid
2		
2	Diesel Engine Fuel Oil Storage Tank	
2		
2	Quantity	1/Station
2	Capacity (gal)	50,000
2	Material of Construction	C. S.
2	Location	Yard, Underground
2		
2	Fuel Oil Day Tank	
2		
2	Quantity	1/Station
2	Capacity (gal)	550
2	Material of Construction	C. S.
2	Location	SSF, Generator Room
2		
2	Diesel Engine Fuel Oil Transfer Pump	
2		
2	Quantity	1/Station
9	Nameplate Design Pressure (psig)	150
9	Nameplate Design Temperature (°F)	125
9	Design Flow Rate (gpm)	13.6
9	Differential Pressure (psid)	30

2 **Table 9-14 (Page 3 of 3). SSF System Main Components**

2	Type	Rotary
2	Material of Construction	C. S.
2	Fluid	No. 2 Diesel Fuel Oil
2		
2	<u>SSF Fuel Oil Transfer Filter</u>	
2		
2	Quantity	*2/Station
2	Design Pressure (psig)	150
2	Design Temperature (°F)	125
2	Design Flow Rate (gpm)	20
2	Retention for 25-Micron Particles (%)	99
2	Maximum Pressure Drop @ 65% Plugged (ft)	32
2	Type	*Duplex Arrangement
2	Material of Construction	S. S.
2		
2	<u>Fuel Oil Recirculation Pump</u>	
2		
2	Quantity	1/Station
2	Design Pressure (psig)	30
2	Design Temperature (°F)	90
2	Design Flow Rate (gpm)	30
2	Design Head (ft)	32
2	Type	Rotary
2	Material of Construction	C. I.
2	Fluid	No. 2 Diesel Fuel Oil
2		
2	<u>Fuel Oil Recirculation Filter</u>	
2		
2	Quantity	1/Station
2	Design Pressure (psig)	30
2	Design Temperature (°F)	90
2	Design Flow Rate (gpm)	30
2	Retention for 25-Micron Particles (%)	100
2	Maximum Pressure Drop @ 65% Plugged (ft)	13.5
2	Type	Simplex
2	Material of Construction	S. S.
2		
9	<u>Unloading Oil Spill Sump Pump</u>	
2		
2	Quantity	1/Station
2	Design Pressure (psig)	35
2	Design Temperature (°F)	100
2	Design Flow Rate (gpm)	32
2	Type	Centrifugal, Submersible
2	Material of Construction	C. I.
2	Fluid	Groundwater and No. 2 Fuel Oil Spillage

Table 9-18. Design Basis Tornado Missiles Minimum Barrier Thicknesses

		Modified Petry Formula				Modified N.D.R.C. Formula			
	Missile	Penetration Depth Horiz Strike (D)	Min. Thickness (3D)	Penetration Depth Vert. Strike (D)	Min. Thickness (3D)	Penetration Depth Horiz. Strike (D)	Min. Thickness (D)	Penetration Depth Vert. Strike (D)	Min. Thickness (D)
9	1	2.64	7.92	1.39	4.17	4.07	12.21	2.95	8.85
9	2	3.39	10.17	1.72	5.16	4.39	13.17	3.19	9.57
9	3	4.77	14.31	2.41	7.23	2.02	6.06	1.46	4.38
9	4	3.54	10.62	1.79	5.37	6.85	20.55	4.97	14.91
9	5	1.96	5.88	0.99	2.97	4.97	14.91	3.61	10.83
9	6	0.51	1.53	0.26	0.78	7.08	21.24	5.14	15.42

Note:

1. All Penetration Depths are calculated based on a concrete strength f'c of 5000 PSI.
2. All Penetration Depths and Minimum Barrier Thicknesses are in inches.

0
0

Figure 9-6.
Deleted per 1990 Update

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 10. STEAM AND POWER CONVERSION SYSTEM

10.1 SUMMARY DESCRIPTION

The Steam and Power Conversion System (SPCS) is designed to convert the heat produced in the reactor to electrical energy.

The superheated steam produced by the steam generators is expanded through the high pressure turbine and then exhausted to the moisture separator reheaters. The moisture separator section removes the moisture from the steam and the two stage reheaters superheat the steam before it enters the low pressure turbines. The steam then expands through the low pressure turbines and exhausts into the main condenser where it is condensed and returned to the cycle as condensate. The heat rejected in the main condenser is removed by the Condenser Circulating Water System.

The first stage reheaters are supplied with steam from the A bleed steam line and the condensed steam is cascaded to the B feedwater heaters. The second stage reheaters are supplied with main steam and the condensed steam cascades to the A feedwater heaters. Heat for the feedwater heating cycle is supplied by the moisture separator reheater drains and by steam from the turbine extraction points.

The hotwell pumps take suction from the condenser hotwell and discharge to the condensate polishing demineralizers. Downstream of the polishers, the condensate flows through the condensate coolers, generator water coolers, hydrogen coolers, condenser steam air ejectors and the S.P.E. steam seal condenser before discharging to the suction of the condensate booster pumps. After the condensate booster pumps, the condensate passes through three stages of low and intermediate pressure feedwater heaters (F, E, and D). The flow passes through the C feedwater heater, then it divides to the suction of the steam generator feedwater pumps. The steam turbine driven main feedwater pumps deliver feedwater through two stages of high pressure feedwater heaters (B and A), to a single feedwater distribution header where the feedwater flow is divided into two lines to the steam generators.

The safety-related features of the SPCS include the main steam piping from the steam generators up to
and including the main turbine stop valves. The steam lines supplying the emergency feedwater pump
0 turbine are also safety-related. The feedwater piping from the feedwater control valves to the steam
generator and the Emergency Feedwater System (EFWS) is also safety-related.

4 SPCS safety-related instrumentation includes the steam generator level instruments which input to the
4 EFWS steam generator level control and steam generator dryout protection circuits. Another QA control
4 circuit monitors UST level and closes the UST to Hotwell makeup valves regardless of hotwell level in
4 order to maintain a minimum 6 foot level in the UST for an EFWS suction source. Other UST level
4 indication is used for post-accident monitoring. The only additional safety-related instrumentation
5 associated with the SPCS is the steam generator outlet pressure used for post-accident monitoring and as
8 input to the Main Steam Line Break (MSLB) circuitry.

10.2 TURBINE-GENERATOR

10.2.1 DESIGN BASES

The turbine-generator converts the thermal energy of steam produced in the steam generators into mechanical shaft power and then into electrical energy. Each unit is operated primarily as a base loaded
7 unit, but may be used for load following when required.

A maximum rate of turbine load change of 10 percent full load per minute is permitted by the Turbine Electro-Hydraulic Control (EHC) System without restriction if the minimum load involved in the change is 46 percent full load or greater. Below 46 percent full load, the maximum rate of change is still 10 percent full load per minute, but the total load change may be restricted by turbine metal temperature considerations.

The rate of change of reactor power is limited to values consistent with the characteristics of the Reactor Coolant System and its control systems. These limitations are imposed by the Integrated Control System
9 on the Steam and Power Conversion System. See Section 7.6.1.2, "Integrated Control System" and
9 Table 7-6.

Turbine-generator functions under normal, upset, emergency, and faulted conditions are monitored and controlled automatically by the Turbine Control System (TCS). The TCS includes redundant mechanical and electrical trip devices to prevent excessive overspeed of the turbine-generator. Additional external trips are provided to ensure operation within conditions that preclude damage to the turbine-generator. A standby manual control system is also provided in the event that the automatic control system is not available.

10.2.2 DESCRIPTION

Each unit's turbine-generator consists of a tandem (single shaft) arrangement of a double-flow high-pressure turbine, and three identical double-flow low pressure turbines driving a direct-coupled generator at 1800 rpm. The turbine is operated in a closed feedwater cycle which condenses the steam, and the heated feedwater is returned to the steam generators. The system is designed to utilize the entire output from the Nuclear Steam Supply System. The turbine generator is manufactured by the General Electric Company of Schenectady, New York.

The flow of main steam is from the steam generators to the high-pressure turbine through four stop valves and four control valves. After expanding through the high-pressure turbine, exhaust steam passes through
1 external moisture separators and two stage steam-to-steam, shell and tube type reheaters. 'A' bleed
1 extraction steam from the high-pressure turbine is supplied to the first reheater stage tube bundle in each reheater. Main steam is supplied to the second reheater stage tube bundle in each reheater. Reheated steam is admitted to the three low pressure turbines and expands through the low-pressure turbines to the main condensers.

Bleed steam for the six stages of feedwater heating is provided from the following sources:

Heater	Extraction Source
A	H-P turbine
B	H-P turbine
C	H-P turbine exhaust
D	L-P turbines
E	L-P turbines
F	L-P turbines

8 Each main generator is a 1038 MVA, 1800 rpm, direct connected, 3 phase, 60 cycle, 19,000 volt conductor
7 cooled synchronous generator rated at 0.90 P.F., and 0.50 SCR at hydrogen pressure of 60 psig. Generator rating, temperature rise, and class of insulation are in accordance with IEEE standards. Excitation is provided by a shaft driven alternator with its output rectified.

10.2.3 TURBINE DISK INTEGRITY

10.2.3.1 Materials Selection

Turbine wheels and rotors are made from vacuum melted or vacuum degassed Ni-Cr-Mo-V alloy steel by processes which minimize flaw occurrence and provide adequate fracture toughness. Tramp elements are controlled to the lowest practical concentrations consistent with good scrap selection and melting practices, and consistent with obtaining adequate initial and long life fracture toughness for the environment in which the parts operate. The turbine wheel and rotor materials have the lowest Fracture Appearance Transition Temperatures (FATT) and highest Charpy V-notch energies obtainable, on a consistent basis from water quenched Ni-Cr-Mo-V material at the sizes and strength levels used. Since actual levels of FATT and Charpy V-notch energy vary depending upon the size of the part and the location within the part, etc., these variations are taken into account in accepting specific forgings for use in turbines for nuclear application. Charpy tests essentially in accordance with Specification ASTM A-370 are included.

10.2.3.2 Fracture Toughness

Suitable material toughness is obtained through the use of materials described in Section 10.2, "Turbine-Generator" to produce a balance of adequate material strength and toughness to ensure safety while simultaneously providing high reliability, availability, and efficiency during operation. Bore stress calculations include components due to centrifugal loads, interference fit, and thermal gradients where applicable. The ratio of material fracture toughness, K_{IC} (as derived from material tests on each wheel or rotor) to the maximum tangential stress for wheels and rotors at speeds from normal to 115 percent of rated speed (the highest anticipated speed resulting from a loss of load is 110 percent) is at least $2\sqrt{\text{in.}}$

Turbine operating procedures are employed to preclude brittle fracture at start-up by ensuring that the metal temperature of wheels and rotors is adequately above the FATT and is sufficient to maintain the fracture toughness to tangential stress ratio at or above $2\sqrt{\text{in.}}$

10.2.3.3 Turbine Design

The turbine assembly is designed to withstand normal conditions and anticipated transients including those resulting in turbine trip without loss of structural integrity. The design of the turbine assembly meets the following criteria:

1. Turbine shaft bearings are designed to retain their structural integrity under normal operating loads and anticipated transients, including those leading to turbine trips.

2. The multitude of natural critical frequencies of the turbine shaft assemblies existing between zero speed and 20 percent overspeed is controlled in the design and operation so as to cause no distress to the unit during operation.
3. The maximum tangential stress in wheels and rotors resulting from centrifugal forces, interference fit and thermal gradients does not exceed 0.75 of the yield strength of the materials at 115 percent of rated speed.

10.2.3.4 Pre-service Inspection

The pre-service inspection program is as follows:

1. Wheel and rotor forgings are rough machined with minimum stock allowance prior to heat treatment.
2. Each finish machined wheel and rotor is subjected to 100 percent volumetric (ultrasonic), surface, and visual examinations using General Electric acceptance criteria. These criteria are more restrictive than those specified for Class 1 components in the ASME Boiler and Pressure Code, Sections III and V, and include the requirement that subsurface sonic indications are either removed or evaluated to assure that they will not grow to a size which compromises the integrity of the unit during the service life.
3. All finish machined surfaces are subjected to a magnetic particle test with no flaw indications permissible.
4. Each fully bucketed turbine rotor assembly is spin tested at or above the maximum speed anticipated following a turbine trip from full load.

10.2.4 SAFETY EVALUATION

The turbine-generator and all related steam handling equipment are of conventional proven design. This
8 unit automatically follows the core thermal power demand (CTPD) requirements in order to meet the
8 unit power demand, See Section 7.6.1.2, "Integrated Control System." There is also a tie-in with Keowee
Hydro Station which can carry auxiliary load upon turbine trip.

7 Under normal operating conditions, it is possible for this system to become contaminated only through
steam generator tube leaks. In this event, radioactivity in the Main Steam System is detected and
measured by monitoring condenser air ejector off-gas which is released through the unit vent and by
7 monitoring the steam generator water samples.

No radiation shielding is required for the components of the turbine-generator and related steam handling equipment. Continuous access to the components of this system is possible during normal conditions.

The condensate polisher demineralizers are available to remove radioactive particulates from the condenser hotwell in the event of primary to secondary leakage.

The turbine-generator is designed and manufactured in accordance with General Electric Company design
criteria and manufacturing practices, procedures, and processes, as well as its Quality Assurance Program.
9 The turbine-generator equipment conforms to the applicable ASA, ASME, and IEEE standards.

10.3 MAIN STEAM SYSTEM

10.3.1 DESIGN BASES

The Main Steam System is designed to achieve the following:

1. Provide steam flow requirements at main turbine inlet design conditions.
2. Dissipate heat from the Reactor Coolant System following a turbine and/or reactor trip by dumping steam to the condenser and atmosphere.
3. Provide steam as required for:
   a. Main and emergency feedwater pump turbines
   b. Condenser air ejectors
   c. Main feedwater pump turbine seals
   d. Steam reheaters
   e. Miscellaneous auxiliary equipment

9 4. Conform to applicable design codes.

5. Allow visual in-service inspection.
6. Protect adjacent equipment against heat damage.

The following portions of the system are designed to withstand seismic loading (criteria for seismic loading
9 defined in Section 3.2.1, "Seismic Classification";

1. Main steam lines from steam generator through the turbine stop valves
2. Main steam line relief valves
3. The steam supply from the main steam lines to the emergency feedwater pump turbine including valve AS-38 and that portion of the auxiliary steam supply downstream from the valve

6 4. Through the first valve of all other lines leaving the main steam lines upstream of the turbine stop
6 valves

10.3.2 DESCRIPTION

Main steam is generated in the two steam generators by feedwater absorbing heat from the Reactor Coolant System. Main steam is conveyed by two lines, one per steam generator, to the turbine inlet valves. A pressure equalization and steam distribution header is connected to each main steam line upstream of the turbine inlet valves. The Main Steam System from the steam generators through the
6 turbine stop valves (including connected piping through the first isolating valve of connecting lines
6 upstream of the turbine stop valves) is Duke Piping Class F. All other piping is Class G. Main Steam piping inside the Reactor Building is considered Reg. Guide 1.26 Quality Group B for purposes of Inservice Inspection. See Figure 10-1, Figure 10-2, and Figure 10-3.

Eight self-actuated safety valves are located on each main steam line (a total of sixteen) to prevent overpressurization of the Main Steam System under all conditions. The valves are designed to pass 105

percent of the Engineered Safeguard Design (ESD) steam flow at a pressure not exceeding 110 percent of
9 the system design pressure (1050 psig). See Table 3-1 for applicable codes.

The main steam lines and the main and emergency feedwater lines are the only lines of the Steam and
Power Conversion System which penetrate the Reactor Building. These lines can be isolated by the
6 turbine stop valves and the main and emergency feedwater line valving. Each of the lines utilized for
6 normal operation leaving the main steam lines before the turbine stop valves has motor operated valves to
complete the isolation of a steam generator. These lines are:

1. Steam bypass to condenser and steam supply for auxiliary steam header (See Figure 10-1 for line to auxiliary steam header)
2. Supply to feedwater pump turbines and condenser air ejectors
3. Supply to steam reheaters
4. Supply to emergency feedwater pump turbine.

4 The arrangement of the valving and parallel piping shown schematically in Figure 10-1 minimizes
6 blowdown of both steam generators from a single leak in the system with the assumption that the turbine
6 stop valves close. For a majority of the Main Steam system, a postulated piping break would only
4 depressurize one steam generator. However, if the break were to occur in either the steam supply to the
4 auxiliary steam header or the emergency feedwater pump turbine cross-connect, blowdown of both steam
4 generators could result. The motor operated valves that are used to isolate the leak require operator
4 action to close and may not get closed until the steam generators are considerably depressurized. This
4 situation has been analyzed and shown to have consequences that are bounded by the consequences of
9 the accidents in Section 15.13, "Steam Line Break Accident" and Section 15.17, "Small Steam Line Break
9 Accident."

7 Normally only one Unit is aligned to supply the Auxiliary Steam System. However, during periods of
7 high steam usage, or when switching from one Unit to the other, multiple Units may be aligned to the
7 Auxiliary Steam System. This situation has been analyzed, and determined that no unreviewed safety
7 question exists (Reference 3).

The steam supply for the emergency feedwater pump turbine (Figure 10-1) will come from either of two
6 sources (the main steam line or the auxiliary steam header) and exhausts to the atmosphere. The solenoid
operated valve which controls the steam shutoff valve MS-93 is de-energized on loss of both main
feedwater pumps, thus opening the steam shutoff valve. As the steam shutoff valve leaves the closed
position, a limit switch starts the emergency feedwater pump turbine bearing oil pump.

6 10.3.3 SAFETY EVALUATION

The Main Steam System delivers the generated steam from the outlet of the steam generators to the various system components throughout the Turbine Building without incurring excessive pressure losses. Steam is generated at approximately 50°F superheat conditions. Functional requirements of the system are as follows:

1. Achieve optimum pressure drop between the steam generators and the turbine steam stop valves.
2. Assure similar steam conditions between each steam stop valve and between each steam generator.
3. Achieve adequate piping flexibility for acceptable forces and moments at equipment interfaces.
4. Assure adequate draining provisions for startup and for operation with saturated steam.

The once-through nature of this recirculating steam condensate cycle is utilized in the removal of contaminants resulting from steam generator leaks, since it allows the flow through the steam generator to be subjected to purification. Radioactive contaminants will be removed by the Powdex polishing
9 demineralizers as described for the control of impurities (Section 10.3.5.1, "Secondary Side Water
9 Chemistry"). Provision is made for transferring the backwashed resins, when they contain radioactive material, as radwaste.

Trips, automatic corrective actions, and alarms will be initiated by deviations of system variables within the Steam and Power Conversion System. In the case of automatic corrective action in the Steam and Power Conversion System, appropriate automatic corrective action will be taken to protect the Reactor Coolant System. The more significant malfunctions or faults which cause trips, automatic actions or
2 alarms in the Steam and Power Conversion System are listed in Section 10.4.6.5, "Instrumentation
2 Application."

2

9 The analysis of the effect of loss of full load on the Reactor Coolant System is discussed in Section 15.8,
9 "Turbine Trip Accident." Analysis of the effects of partial loss of load on the Reactor Coolant System is
9 discussed in Section 7.6.1.2.3.2, "Loss-of-Load Considerations."

The effects of inadvertent steam relief or steam bypass are covered by the analysis of the steam line break
9 given in Section 15.13, "Steam Line Break Accident," and in Section 15.17, "Small Steam Line Break
9 Accident." The effects of an inadvertent rapid throttle valve closure are covered by the turbine trip discussion in Section 15.8, "Turbine Trip Accident."

9 Following a turbine trip, a reactor trip will occur if reactor power is above the anticipatory reactor trip
9 system (ARTS) setpoint. The safety valves will relieve excess steam until the output is reduced to the point at which the steam bypass to the condenser can handle all the steam generated. Steam may also be released to the atmosphere through a manually operated angle-body control valve on each main steam line.

Pressure relief is required at the system design pressure of 1050 psig, and the first safety valve bank will be set to relieve at this pressure. The design pressure is based on the operating pressure of 925 psia plus a 10 percent allowance for transients and a 4 percent allowance for blowdown. Additional safety valve banks will be set at pressures up to 1104 psig, as allowed by the ASME Code. Pressure relief is provided by eight safety valves on each main steam line, and the valve relief pressures are:

Number of Valves	Relief Pressure (psig)
1	1050 ± 11
1	1065 ± 11
1	1080 ± 11
1	1090 ± 11
2	1100 ± 11
2	1104 ± 11

6 The relief valve capacity is such that the energy generated at the reactor high power level trip setting can be dissipated through this system.

10.3.4 INSPECTION AND TESTING REQUIREMENTS

Steam from the steam generators is admitted to the turbine through four cast 24 inch main steam stop valves, arranged in parallel and located in the main steam lines upstream from the turbine control valves

(See Figure 10-1). In the event of a steam line rupture accident, the stop valves serve to isolate the
8 unaffected steam generator. See Section 10.3.2, "Description."

The main steam stop valve is designed for tight seating throughout its life. The valve stem extends through a guide bushing which centers the disc on the stem with some degree of freedom, permitting self alignment of the disc on its seat. The valve seat and disc have spherical seating surfaces so that perfect contact is made even if they are not in precise alignment. The use of stem sealing permits relatively large stem to bushing clearance, minimizing the possibility of stem sticking. The seating surfaces of the valve and the stem seal are hardened inlay contact areas which resist erosion and mechanical damage and assure tightness. A coarse-mesh internal screen strainer with removable fine mesh startup strainer is provided for each stop valve.

The main steam stop valves are fail-safe, requiring hydraulic pressure to open and closure is
8 spring-assisted. The number two stop valve, MS-104, on each unit is a continuously positioned valve
8 while the other stop valves have only two positions: fully opened and fully closed. Each stop valve will
be tested periodically (while the turbine is in operation) and any tendency of the valve to remain open in opposition to a control signal will be detected. A stop valve will be disassembled, inspected, and required corrective action taken when a valve test warrants such action. Stop valves are also disassembled and inspected during turbine inspections.

The main steam stop valves are designed and tested to assure proper functioning. In the event of a steam line rupture accident, the two stop valves serving the unaffected steam generator will close in the presence of steam flow in the normal direction, thus precluding the possibility of reverse flow through the other two stop valves.

The motor operated valve on each of the lines connected to the main steam lines can be tested for
4 operability when the unit is shutdown. These valves, the main steam stop valves, and the check valves
4 that are provided in the two branch lines that cross-connect the main steam lines prevent uncontrolled
4 blowdown of the unaffected steam generator in the unlikely event of a main steam line break. Their
ability to close will be verified at periodic intervals.

Proper operation of the emergency feedwater pump and turbine, the steam shutoff valve (Figure 10-1), and the valves in the emergency feedwater supply to the steam generators (Figure 10-8) can be demonstrated when the unit is shutdown. The emergency feedwater pump and turbine, and the steam shutoff valve can be tested anytime by utilizing the recirculation test line. Proper functioning of the emergency feedwater supply will be verified at periodic intervals.

10.3.5 WATER CHEMISTRY

10.3.5.1 Secondary Side Water Chemistry

4 Hydrazine and/or carbohydrazide is added to the feedwater downstream of the condensate polishing
4 demineralizers for oxygen control. An alternate addition point is directly to the condensor hotwell.

3 Ethanolamine or an alternate approved amine is used to increase pH to minimize formation of corrosion
products.

7 A Titanium solution may be injected into the feedwater system downstream of the main feedwater pumps
7 to mitigate intergranular attack (IGA) and intergranular stress corrosion cracking (IGSCC) of steam
7 generator tubing.

The condensate polishing demineralizer utilizes the Powdex process, developed by Graver Water Conditioning Company as a unique, high quality water purification system. The Powdex units will function as a combination demineralizer and high purity filter, treating 100 percent of the feedwater flow
8 to the steam generator under conditions of startup, reduced load, and normal full-load operation.

The Powdex process uses extremely fine particle-size (60-400 mesh) ion exchange resins which are applied to the external surface of specially design filter elements. The rapid ion exchange rates of these fine resins allows the use of a thin coating (1/16 inch to 1/2 inch) on the elements and permits a greater utilization of the ultimate capacities of the resins than is the case of bead type resins.

The Powdex resins are not chemically regenerated for repeated use but are replaced with fresh resins upon exhaustion. This continued resin replacement allows complete flexibility in the selection of the most advantageous type of resin or combination of resins for the removal of specific impurities.

The resins are selected for the effective removal of dissolved metallic cations and also anions such as halides, silicates, and sulfates. In addition, the resin will also remove by filtration the suspended and colloidal trace impurities such as corrosion products.

Exhaustion of each batch of resins is monitored and is indicated by an increase in pressure drop or by a decrease in treated water quality. Exhausted resins are backwashed from the units and pumped to a disposal facility.

10.4 OTHER FEATURES OF STEAM AND POWER CONVERSION SYSTEM

10.4.1 MAIN CONDENSER

10.4.1.1 Design Bases

The main condenser is designed to condense turbine exhaust steam for reuse in the steam cycle. The main condenser also serves as a collecting point for various steam cycle vents and drains to conserve condensate which is stored in the condenser hotwell. The condenser also serves as a heat sink for the
8 Turbine Bypass System which is capable of handling approximately 25 percent of rated main steam flow. Rejected heat is removed from the main condenser by the Condenser Circulating Water System.

10.4.1.2 System Description

The main condenser consists of three surface type deaerating condenser shells with each shell condensing the exhaust steam from one of the three low pressure turbines. The condenser shells are of conventional shell and tube design with steam on the shell side and circulating water in the tubes. One low pressure feedwater heater is mounted in the neck of each of the condenser shells. The combined hotwells of the three condenser shells have a water storage capability equivalent to approximately 10 minutes of full load operation (nominally 142,000 gallons). The internal condenser design provides for the effective condensing of steam, scavenging and removal of noncondensable gases, and the deaeration of the condensate. Impingement baffles are provided to protect the tubes from incoming drains and steam dumps.

The main condenser can accept a bypass steam flow of approximately 18 percent of rated main steam flow without exceeding the turbine high backpressure trip point with design inlet circulating water
8 temperature. This bypass steam dump to the condenser function is in addition to the normal condenser
8 functions expected.

10.4.1.3 Safety Evaluation

The main condenser is not assigned a safety class as it is not required for a safe reactor shutdown. The inventory of radioactive contaminants in the main condenser is a function of primary to secondary system leakage.

10.4.1.4 Tests and Inspections

8 Cleaning and Inspection of the Main Condensers is performed each Refueling Outage. Condenser
9 performance is monitored and trended per the Site Thermal Performance Program. The conductivity,
8 sodium content, and oxygen content of the condensate leaving the hotwell is continuously monitored.
8 The condensate system's polishing demineralizer will remove many of the contaminants and thus reduce
8 the impact of any leakage from the Condenser Circulating Water upon final feedwater chemistry.

8

10.4.1.5 Instrumentation Application

The main condenser hotwell is equipped with level control devices for automatic control of condensate makeup and rejection. On low water level in the hotwell, control valves supply condensate from the
5 upper surge tanks to the hotwell by gravity. A QA-1 control circuit monitors UST level and closes the
4 UST to Hotwell valves regardless of Hotwell level in order to maintain a minimum 6 foot water level in
4 the UST for an EFWS suction source. A low hotwell level alarm is provided in the control room. Loss of condenser vacuum will trip the respective unit turbine. All instrumentation for this system is operating instrumentation, and none is required for safe shutdown of the reactor.

10.4.2 MAIN CONDENSER EVACUATION SYSTEM

10.4.2.1 Design Bases

The Main Condenser Evacuation System is designed to remove noncondensable gases and air inleakage from the steam space of the three shells of the main condenser. The Main Condenser Evacuation System consists of the Condenser Steam Air Ejector System and the Main Vacuum System which are shown on Figure 10-5 for Oconee 1, 2 and 3.

10.4.2.2 System Description

The Condenser Steam Air Ejector System consists of three condenser steam air ejectors (CSAE) per unit. Normally each CSAE draws the noncondensable gases and water vapor mixture from one of the three main condenser shells to the first air ejector stage. The mixture then flows to the intercondenser where it is cooled to condense the water vapor and motive steam. The second air ejector stage draws the uncondensed portion of the cooled mixture from the intercondenser and compresses it further. The compressed mixture then passes through the aftercondenser where it is cooled and more water vapor and motive steam are condensed. The intercondenser drains back to the main condenser and the aftercondenser drains to the condensate storage tank.

The Main Vacuum System consists of three main vacuum pumps connected to the condenser crossties on the Condenser Steam Air Ejector System to allow the main vacuum pumps to evacuate the main condenser, the main turbine casing, and the upper surge tanks during startup. These pumps are only used during startup since normal operation requires the use of the CSAE only.

10.4.2.3 Safety Evaluation

The Main Condenser Evacuation System is not assigned a safety class as it is not required for a safe reactor shutdown. Control functions of the Main Condenser Evacuation System indirectly influence Reactor Coolant System operation in that upon loss of vacuum the main condenser no longer provides a heat sink.

The noncondensable gases and water vapor mixture discharged to the atmosphere from the Main Condenser Evacuation System are not normally radioactive; however, in the event of primary to secondary system leakage due to a steam generator tube leak, it is possible for the mixture discharged to become radioactive. A full discussion of the radiological aspects of a primary to secondary leakage including radioactive discharge rates under postulated design conditions is discussed in Chapter 11, "Radioactive Waste Management" and Chapter 15, "Accident Analyses."

10.4.2.4 Tests and Inspections

Proper operation of the Main Condenser Evacuation System is verified during unit startup, and is subject to periodic inspections by plant operating personnel. A flowmeter is provided in the discharge piping of each CSAE. Periodic readings of these flowmeters will indicate whether or not the air inleakage to the condenser is within acceptable limits. These readings will also indicate the operating effectiveness of the CSAE.

10.4.2.5 Instrumentation Applications

A radiation monitor is provided in the exhaust line from the CSAE's with remote indicator, recorder, and alarm located in the Control Room. Local indicating devices for pressure, temperature, and flow are provided as required for monitoring system operation. All instrumentation for this system is operating instrumentation and none is required for safe shutdown of the reactor.

10.4.3 TURBINE GLAND SEALING SYSTEM

10.4.3.1 Design Bases

The Turbine Gland Sealing System (TGS) is designed to seal the annular openings around the rotor shafts of the high pressure (HP) and low pressure (LP) main turbines and the feedwater pump (FDWP) turbines where the shafts emerge from the shell casings. All seals for the LP main turbines and the exhaust end seals for the FDWP turbines are designed to prevent the leakage of atmospheric air into the turbines since the turbine shell pressures at these seal locations are subatmospheric at all unit loads. All seals for the HP main turbine and the steam inlet end seals for the FDWP turbines are designed to prevent atmospheric air leakage into the turbines since the turbine shell pressures at these seal locations vary from subatmospheric to above atmospheric as these turbines progress from startup to normal operation.

10.4.4 TURBINE BYPASS SYSTEM

10.4.4.1 Design Bases

The Turbine Bypass System (TBS) is designed to reduce the magnitude of nuclear system transients following large turbine load reductions by dumping main steam directly to the main condenser and/or to the atmosphere, thereby creating an artificial load on the reactor.

10.4.5 CONDENSATE CLEANUP SYSTEM

10.4.5.1 Design Bases

(See Section 10.3.5.1, "Secondary Side Water Chemistry")

10.4.5.2 System Description

9 The Condensate Cleanup System (CCS) for each unit consists of five powdered resin condensate polishing demineralizer vessels. Normally, all five vessels will be in service. There is also a separate regeneration skid for each unit consisting of a recirculation/resin feed tank and a precoat pump.

The current revision of the SGOG PWR Secondary Water Chemistry Guidelines (Chapter 3, "Design of Structures, Components, Equipment, and Systems") and vendor recommendations are used to derive the operating specifications which are addressed in the Chemistry Section Manual.

The condensate polishing demineralizers are designed for automatic operation following mode initiation. This means that the operator is required to initiate each Phase of operation but, having once done so the polishers will operate automatically through that mode (i.e., backwash, precoat, filter, and hold). A polisher cycle continues until the effluent water quality deteriorates or until a predetermined differential pressure drop is reached across the polisher. When either of these conditions occur, the polisher will be backwashed.

6 Each polisher vessel normally is backwashed as required to meet secondary-side chemistry specifications. The vessels are backwashed to the Powdex sump. Each backwash takes about 15,000 gallons of water and contains roughly 17 cubic feet of spent resin. The resin water mixture is pumped to the Radwaste
6 Facility Powdex Backwash Tank.

The handling of polisher backwash during and after a steam generator primary to secondary leak is discussed in Chapter 11, "Radioactive Waste Management."

10.4.5.3 Safety Evaluation

The Condensate Cleanup System is not assigned a safety class as it is not required for a safe reactor shutdown. The condensate polishing demineralizer vessels and all regeneration equipment are located in the Turbine Building. The spent resin and water mixture discharged to the backwash sump from the polisher vessels is not normally radioactive; however, disposal of the mixture in the event of a primary to secondary leakage is discussed in Chapter 11, "Radioactive Waste Management."

10.4.5.4 Tests and Inspections

9 Proper operation of the Condensate Cleanup System is verified during unit startup, and is subject to periodic inspections by plant operating personnel.

10.4.6 CONDENSATE AND MAIN FEEDWATER SYSTEMS

10.4.6.1 Design Bases

The Steam and Power Conversion System for each unit is designed to remove heat energy from the reactor coolant in the two steam generators and convert it to electrical energy. The closed feedwater cycle condenses the steam and the heated feedwater is returned to the steam generators. The system is designed to utilize the entire output from the Nuclear Steam Supply System.

8 The Condensate and Main Feedwater Systems operate within the power rate of change constraints
8 discussed in the "Turbine-Generator, Design Bases" section.

8

The Condensate and Main Feedwater Systems are shown in Figure 10-6 and Figure 10-7.

10.4.6.2 System Description

The closed cycle feedwater heaters are half-size units (two parallel strings), with the exception of "F" heater. There are three "F" heaters, one in each condenser neck. Deaeration is accomplished in the condenser.

All three hotwell pumps, two of the three one-half capacity condensate booster pumps and both of the main feedwater pumps are in normal use. Each of two main feedwater pumps is more than one-half capacity.

3

The main steam lines and the main and emergency feedwater lines are the only lines of the Steam and Power Conversion System which penetrate the Reactor Building. These lines can be isolated by the turbine stop valves and the normal and emergency feedwater line valving.

Feedwater supply to the steam generators following a reactor shutdown is assured by one of the following methods:

1. Either of the two main feedwater pumps is capable of supplying both steam generators at full secondary system pressure.
2. The hotwell and condensate booster pump combination has discharge shutoff head of approximately
8 620 psia. Three sets of half-size pumps are provided. If required, the Turbine Bypass System can be used to reduce secondary system pressure to the point where one of the hotwell and condensate booster pump combinations can supply feedwater to both steam generators.
3. A separate Emergency Feedwater System for each unit will supply feedwater at full system pressure (see Section 10.4.7, "Emergency Feedwater System").
4. Alternate auxiliary feedwater supplies are available from the Emergency Feedwater System of each of the other units.
5. The Auxiliary Service Water System may be used to maintain steam generator water inventory following steam generator depressurization to remove decay heat in the long term.
6. The SSF Auxiliary Service Water System is capable of supplying both steam generators of all three units at full secondary system pressure.

10.4.6.3 Safety Evaluation

9

The design, material, and details of construction of the feedwater heaters are in accordance with the ASME Code, Section VIII, Unfired Pressure Vessels.

8

The Feedwater System has been reviewed to determine the potential for "water hammer" during anticipated operational occurrences. It has been concluded that the existing Oconee Feedwater System is adequate to prevent flow instabilities. Because design features of the feedwater system preclude the probability of destructive "water hammer" forcing functions resulting from uncovering feedwater lines, no analyses have been performed nor test program conducted regarding this occurrence. The following considerations support this conclusion:

1. Neither the Main nor Emergency Feedwater Systems has horizontal or downward-sloping pipe runs adjacent to the steam generator. The auxiliary piping remains below the level of its junction with the steam generator. The main feedwater line rises above its steam generator connection only after downward and horizontal runs which effectively form a loop seal. Only in the unlikely event of steam generator shell pressure near the vapor pressure of the water in this pipe could a steam void occur.

2. The main and emergency feedwater distribution heads on the steam generator are designed to remain flooded regardless of steam generator water level, and would in any event be self-venting if steam were introduced. The main ring header is fed from the bottom, external to the steam generator, and empties upward through the vertical inlet lines. The auxiliary ring headers on Oconee 1 and 2 are similar in design to the main header. The original Oconee 3 auxiliary header was internal to the
8 steam generator shell, however, the currently installed header is similar in design to Oconee 1 & 2.
None of the feedwater headers can spontaneously drain into the steam generator.

3. Each steam generator has its auxiliary header separate from the main header. Therefore, there is no
5 need to deliver the relatively cool auxiliary feedwater through the normal path for main feedwater. In
5 addition, the QA-1 portions of Main FDW have been analyzed for pressure transient forces due to
5 control valve closure and pump trip resulting from actuation of the Main Steam Line Break Detection
7 and Feedwater isolation circuitry.

10.4.6.4 Tests and Inspections

The operating characteristics of the hotwell, condensate booster, and main feedwater pumps are established throughout the operating range by factory tests. The main condensers, the hotwell pumps, the condensate polishing demineralizer vessels, the condenser steam air ejectors, the gland steam condenser, the condensate booster pumps, the feedwater heaters, and the main feedwater pumps are hydrostatically tested to the applicable code or standard.

Manways or removable heads are provided on all heat exchangers to provide access to the tube sheets for inspection and maintenance. A general routine visual surveillance of the system components and piping during operation and maintenance periods for signs of leakage or distress will be performed to verify system integrity.

10.4.6.5 Instrumentation Application

Sufficient instrumentation is provided to monitor system performance and to control the system automatically or manually under all operating conditions.

2 Trips, automatic corrective actions, and alarms will be initiated by deviations of system variables within
the Steam and Power Conversion System. In the case of automatic corrective action in the Steam and
2 Power Conversion System, appropriate automatic corrective action will be taken to protect the Reactor
Coolant System. The more significant malfunctions or faults which cause trips, automatic actions, or alarms in the Steam and Power Conversion System are:

10.4.6.5.1 Turbine Trips

Any turbine trip provides an anticipatory reactor trip.

1. Loss of D-C supply to trip circuits
0 2. Low condenser vacuum
7 3. Loss of generator stator coolant (if runback fails)
7 4. Loss of both main feedwater pumps
7 5. Turbine overspeed
7 6. Reactor trip
7 7. Bearing oil low pressure
7 8. EHC Hydraulic Fluid low pressure

7 9. Moisture separator high level

7 10. Manual trip

8 11. Loss of speed feedback

10.4.6.5.2 Automatic Actions

4 (Also see Integrated Control System Description.)

4 1. Low Water level in Upper Surge Tank

10.4.6.5.3 Principal Alarms

1. Low pressure at condensate booster pump suction
2. Low pressure at feedwater pump suction
3. Low vacuum in condenser
4. Low water level in condenser hotwell
5. High water level in condenser hotwell
6. High water level in steam generator
7. Low water level in steam generator
8. High pressure in steam generator
9. Low pressure in steam generator
10. Low feedwater temperature
11. Electrical malfunctions in the EHC

4 12. Low water level in Upper Surge Tank

10.4.6.6 Interactions with Reactor Coolant System

8

Following a turbine trip, the reactor will trip automatically due to anticipatory trip logic. The safety valves will relieve excess steam until the output is reduced to the point at which the steam bypass to the condenser can handle all the steam generated.

In the event of failure of a main feedwater pump, there will be an automatic runback of the power demand. The one main feedwater pump remaining in service will carry approximately 60 percent of full load feedwater flow. If both main feedwater pumps fail, the turbine and reactor will be tripped, and the emergency feedwater pumps started.

9 On a low feedwater pump suction header pressure condition, the spare condensate booster pump starts
9 automatically, provided pump start permissives are satisfied.

10.4.7 EMERGENCY FEEDWATER SYSTEM

10.4.7.1 Design Bases

The Emergency Feedwater (EFW) System assures sufficient feedwater supply to the steam generators of each unit, in the event of loss of the Condensate/Main Feedwater System, to remove energy stored in the core and primary coolant. The EFW System is designed to provide sufficient secondary side steam generator heat sink to enable cooldown from reactor trip at power operation down to cold shutdown conditions. The EFW System may also be required in some other circumstances such as cooldown following a loss-of-coolant accident for a small break. The EFW System is shown in Figure 10-8.

2 The EFW System is designed to start automatically in the event of loss of both main feedwater pumps as
6 indicated by Main Feedwater Pump low hydraulic oil pressure. In addition, low water level in either
2 steam generator, after a 30 second delay to prevent spurious actuations, will start the Motor Driven
6 Emergency Feedwater Pumps. The EFW System will supply sufficient feedwater to enable the Reactor
Coolant System to cool down to conditions at which the Decay Heat Removal System may be operated.

Three EFW pumps are provided, powered from diverse power sources. Two full capacity motor-driven pumps are powered by the emergency A.C. Power System, each supplying feedwater to one steam generator. One turbine-driven pump, supplying feedwater to both steam generators, may be driven by any of three separate steam sources; A Main Steam, B Main Steam, or plant start-up steam (also called the Auxiliary Steam System). Although the total rated capacity of all three EFW pumps is 1780 gal/min, the flow capacity of any one of the pumps is sufficient to enable safe and orderly cooldown of the Reactor Coolant System. Sufficient redundancy and valving are provided in the design of the EFW piping system with isolation and cross-connections allowing the system to perform its safety-related function in the event of a single failure coincident with a secondary pipe break and the loss of normal station auxiliary A.C. power. All automatic initiation logic and control functions are independent from the Integrated Control System (ICS).

The three units are provided with separate EFW Systems. The discharge header of each EFW System is cross connected making each system capable of supplying either unit.

Automatic initiation of the turbine-driven EFW pump is independent of AC power. Based on the
required emergency feedwater flow, sufficient inventory of EFW is available for maintaining hot shutdown
6 for at least 75 minutes from both upper surge tanks. The inventory in the upper surge tanks is assured by
4 auto closure of the hotwell makeup control valves on a low upper surge tank level signal. The upper
surge tanks and the associated piping from them to the EFW pump suctions are seismically qualified. The condenser hotwell is also seismically qualified with a nominal capacity of 120,000 gallons. However, the condenser hotwell is seismically qualified without any piping connected to it, and not all of the piping from the hotwell to the EFW pump suctions has been seismically qualified.

In the event of a postulated break in the Main Steam or Main Feedwater System inside or outside containment coupled with a single active failure, the EFW System provides sufficient flow to ensure adequate core cooling.

The plant transient which requires the highest Emergency Feedwater System flow, and as such constitutes
2 the Emergency Feedwater design basis transient, is the loss of main feedwater transient. This transient
combines the highest heat load, decay heat plus reactor coolant pump heat, with the minimum heat sink
due to the instantaneous loss of both main feedwater pumps. A discussion of the demand on the EFW
5 system for each transient follows. The following, with the exception of Steam Line Break (Section
5 10.4.7.1.8, "Steam Line Break") and Small Break LOCA (Section 10.4.7.1.9, "Small Break LOCA"),
2 should not be considered Design Basis Transients for the entire plant, but for Emergency Feedwater only.

10.4.7.1.1 Loss of Main Feedwater (LMFW)

Those transients which result in losing feedwater delivery from the Main Feedwater/Condensate System
6 are classified as a loss of main feedwater. Since the reactor coolant pumps remain on, the control valves
0 modulate to control steam generator level at 30 inches. The transient requires feedwater to be delivered at
a rate sufficient to remove decay heat and reactor coolant pump heat. One motor driven emergency
8 feedwater pump delivering 400 gal/min. at a steam generator pressure of 1064 psia and an EFW
temperature of ≤ 130°F will provide adequate heat removal capacity.

3 **10.4.7.1.2 LMFW with Loss of Offsite AC Power (LOOP)**

3 The loss of offsite AC power causes the reactor to trip, the turbine to trip, and the condensate booster
pumps and hotwell pumps to trip causing a loss of main feedwater. The emergency feedwater pumps are
actuated on the main feedwater pump trip. Since the reactor coolant pumps have tripped, steam
3 generator level control increases the level setpoint to 240 inches on the extended startup range to promote
the natural circulation mode of heat removal. The emergency feedwater control valves open to allow full
system flow until the controlling level is attained. Feedwater requirements are determined by core decay
heat removal demand. One motor driven EFW pump can deliver sufficient feedwater to meet the
demand.

3 **10.4.7.1.3 LMFW with Loss of Onsite and Offsite AC Power (Station Blackout)**

6 This transient is the result of a station blackout condition. This transient is similar to the Section
6 10.4.7.1.2, "LMFW with Loss of Offsite AC Power (LOOP)" analysis with the additional assumption
that the onsite emergency AC power sources have been lost. This results in the loss of the motor driven
3 emergency feedwater pumps. This transient is not a design basis event. The turbine-driven emergency
3 feedwater pump should be available for this event because of its AC power independence; however, the
3 SSF ASW is required to remove the decay heat in this transient. The transient is described in Section
3 8.3.2.2.4, "Station Blackout Analysis."

10.4.7.1.4 Plant Cooldown

In addition to providing sufficient heat removal capacity immediately following a transient, the
requirements for plant cooldown from full power operation to RCS temperatures where switchover to the
Decay Heat Removal System can be accomplished has been analyzed. All heat sources have been
included. The average hourly EFW flowrate to meet cooldown rates of 100°F/hr and 50°F/hr down to
6 the switchover temperature of 246°F are given below.

	Cooldown Rate	
Time	100°F/hr.	50°F/hr.
0-1 hr	547 gpm	480 gpm
1-2 hr	464	390
2-3.3 hr	430	-
2-3 hr	-	354
3-4 hr	-	344
4-5 hr	-	331
5-6 hr	-	325
6-6.6 hr	-	320

Cooldown of the RCS is a manual function controlled by the operator such that the EFW flow is throttled to obtain the cooldown rate desired and within Technical Specification and administrative limits.

10.4.7.1.5 Turbine Trip

6 A turbine trip transient causes a reactor trip for reactor power levels higher than the ARTS setpoint. The reactor trip initiates the ICS to control steam generator level at the minimum level so that the main feedwater pumps are run back. With the main feedwater pumps in an untripped condition, there is no requirement for the EFW system to function.

6 10.4.7.1.6 Deleted per 1996 Revision

6

10.4.7.1.7 Main Feedwater Line Break

For a main feedwater line break upstream of the isolation check valve, the transient would have the same response as a loss of main feedwater. A break downstream of the check valve will cause the steam generator to blow down, but will be less severe than a steam line break transient due to less feedwater being delivered to the steam generators. The demand on the EFW system would be for decay heat and reactor coolant pump heat removal via the unaffected steam generator. One motor driven EFW pump has sufficient capacity to perform this function.

10.4.7.1.8 Steam Line Break

A steam line break transient is primarily an overcooling transient. Only after the overcooling has been turned around and after isolation of the affected SG, does the need for heat removal by the intact SG arise. Since the EFW system is capable of delivering to either steam generator, the heat removal demand on the EFW system can be met by one motor driven EFW pump or the turbine driven EFW pump in the event the MFW system is unavailable.

10.4.7.1.9 Small Break LOCA

For certain small break loss of coolant accidents (break sizes less than 0.1 ft^2), feedwater is required to remove the decay heat and reactor coolant pump heat which is not relieved through the break. A flow
8 rate of 400 gal/min is adequate to provide this heat removal (Reference 1). One motor-driven EFW pump has the necessary capacity.

10.4.7.1.10 Summary of Transients

The above transients bound the EFW system performance requirements for all transients.

	Conditions of Transient	Criteria
	Loss of Main Feedwater	Peak RCS Pressure
3	Loss of Offsite Power	≤ 2750 psig
6	Turbine Trip	
	Steam Line Break	10CFR 100 dose limits
	Feedwater Line Break	
	Small Break LOCA	10CFR 100 dose limits
7		10CFR 50.46 PCT limit
3	Station Blackout	Not a design basis event
	Plant Cooldown	100°F/hr

As discussed above, the requirements for EFW system performance are determined by the heat removal demand for the loss of main feedwater transient, and the successful cooldown of the RCS to decay heat
6 removal mode. The assumptions utilized in the analysis of the plant response allow for margin to realistic system performance for conservatism.

System initial conditions are consistent with an assumed initial 102 percent power level. Steam generator
6 level is 50 percent corresponding to 34,500 lbs inventory per steam generator. The Turbine Bypass
6 System is not available so that steam relief is by the main steam safety valves. The EFW system is limited to one motor driven EFW pump delivering to one steam generator. The maximum allowable feedwater temperature for the above conditions is 130°F.

6 A loss of main feedwater is initiated by a failure that causes a reduction in MFW pump speed. It is
6 assumed that MFW flow entering the SGs decreases to zero flow 5 seconds after this failure occurs.
6 Reactor trip and the subsequent turbine trip occur on the high RCS pressure trip function. Reactor
6 coolant pumps are left on to maximize the heat input. Decay heat power is based on infinite burnup with
6 2 sigma uncertainty. The EFW system is assumed to be available 76 seconds after the EFW low level
6 setpoint is reached. For the cooldown part of the transient, all heat sources (decay heat, pump heat, fuel, structural steel, and coolant sensible heat) were included. The feedwater inventory required for a 100°F/hr
3 cooldown to decay heat removal switchover is 94,000 gallons, or 145,000 gallons for a 50°F/hr cooldown.
6 These requirements are well within the available hotwell and upper surge tank capacity. For cooldown in the recirculation mode, the minimum amount of water in the upper surge tank, condensate storage tank and hotwell is the amount needed for 11 hours of operation per unit. This is based on the conservative estimate of normal makeup being 0.5 percent of throttle flow. Throttle flow at full load, 11,200,000 lbs/hr, was used to calculate the operation time. For decay heat removal, the operation time with the volume of water specified would be considerably increased due to the reduced throttle flow.

10.4.7.2 System Description

Each reactor unit is provided with a separate EFW System, as shown in Figure 10-8. Controls for each system are located on the main control room panels. Each EFW System is provided with two full capacity motor driven pumps and one full capacity turbine driven pump. Each of the motor driven pumps normally serves a separate steam generator; the turbine driven pump serves both steam generators.
6 A minimum of 400 gpm total EFW flow is required. The EFW pumps will start automatically as
2 outlined below:

2 <u>Motor Driven EFW Pumps (MDEFWP's):</u>

2 Automatic starting of the MDEFWP's is determined by the position of the control room selector switch
2 for each pump. The MDEFWP's are provided with a four position selector switch which allows the
2 operator to select between Off, Auto 1, Auto 2 and Run. When the selector switch is in the Auto 1
3 position, LOW STEAM GENERATOR WATER LEVEL in either steam generator (OTSG) will start
2 the pump after a 30 second time delay to prevent spurious actuations. When the selector switch is in the
2 Auto 2 position, LOW STEAM GENERATOR WATER LEVEL or LOSS OF BOTH MAIN
2 FEEDWATER PUMPS will start the pump. Loss of both main feedwater pumps is sensed by pressure
6 switches which monitor feedwater pump turbine control oil pressure. Loss of both Main Feedwater
6 Pumps actuation is by the control oil pressure switches sensing loss of feedwater pumps.

2 Turbine Driven EFW Pump (TDEFWP):

2 Automatic starting of the TDEFWP is determined by the position of the control room selector switch for
2 the pump. The TDEFWP is provided with a three position-pull to lock selector switch which requires
2 that the control room operator manually take the switch to the OFF position through a deliberate action.
2 The operator can select between Off, Auto and Run. When the selector switch is in the Auto position,
2 LOSS OF BOTH MAIN FEEDWATER PUMPS will start the pump. Loss of both main feedwater
6 pumps is sensed by pressure switches which monitor feedwater pump turbine control oil pressure. If a
5 main steam line break signal is present and the selector switch is in AUTO, the TDEFWP will
5 automatically stop and prevent an auto start. The operator can manually start the TDEFWP by placing
7 the selector switch to RUN.

8 Once automatically started, the motor-driven EFW pumps will continue to operate until manually secured
by the operator. Each emergency feedwater discharge line to each steam generator is provided with a
5 control valve and check valve. The control valves are normally closed due to steam generator level >
5 30″. The valves are arranged to fail to the automatic control mode upon loss of DC control power to the
manual/auto select solenoid. If the selected train of automatic control fails, then the valve would fail
open. Also, upon loss of station air, the valves will maintain their position with N_2 backup. If N_2
backup fails then the valve would fail open. These modes of operation show that emergency feedwater
2 isolation is not possible with valve control circuitry or motive force failure. Open/Closed valve position
2 indication is provided for each control valve in the main control room at the valve manual loader.

5 In automatic, a solenoid valve on each control valve is de-energized, allowing the valve to receive a
control air signal for valve modulation in response to steam generator level, independent from the ICS.

The EFW pumps normally discharge into separate lines feeding a separate steam generator through the auxiliary feedwater header.

A flow path is also provided to the upper surge tank dome (connected to the condenser) for minimum
0 recirculation flow and testing purposes. A continuous recirculation flow is provided for the turbine driven
pump, limited by fixed orifices. A self-contained automatic recirculation valve is provided for each motor
0 driven pump to assure individual pump minimum flow when needed during operation. A flow path is
0 provided from the discharge of each motor driven pump to the upper surge tank for full flow testing.
Power for the motor driven pumps is normally provided by the normal station auxiliary A.C. Power
3 System. During loss of offsite power operation, these pumps are aligned to the Emergency A.C. Power
System. Motive steam for the turbine driven pump is provided from either of the two steam generators
by main steam lines upstream of the stop valves, and is exhausted to the atmosphere. Either steam
supply will provide sufficient steam for turbine operation. Either steam supply may be isolated if
necessary. A check valve is provided in each steam supply line to prevent uncontrolled blowdown of
9 more than one steam generator (see Section 10.3.2, "Description" also for additional discussions of line
9 breaks in the steam supply cross-connect to the turbine driven emergency feedwater pump).

The condensate/feedwater reserves for each unit are normally aligned to the EFW pump suctions. The condensate/feedwater reserve for each unit is maintained among the sources in Table 10-1.

Each of the EFW pumps is supplied with its own independent starting circuit. The independent control
circuits are powered by the 125 VDC station batteries. These circuits are actuated by trip of both main
6 feedwater pumps. Feedwater pump trip is detected by low feedwater pump turbine hydraulic control oil
6 pressure for turbine driven and motor driven EFW pumps. Each pump is provided with a control switch
with which the operator may start the pump manually.

Sufficient indication is provided in the control room to allow the operator to monitor unit parameters during a cooldown. Specific indication provided for the EFW System are listed in Table 10-2.

Discharge flow from the EFW pumps is normally aligned and controlled by control valves FDW-315 and
FDW-316. These valves are controlled independently of the Integrated Control System and arranged to
fail to the automatic control mode upon loss of DC control power to the manual/auto select solenoid. If
3 the selected train of automatic control fails, then the valve would fail open. Also, upon loss of all station
air, the valves will maintain their position with N_2 backup. If N_2 backup fails, then the valve would fail
5 open. In automatic, the control valve manual/auto select solenoid valves are de-energized, thereby
aligning the valve to automatic control and positioning the valve per the automatic setting. Control
valves FDW-315 and FDW-316 are modulated by separate control air signals. These valves may be
automatically controlled, or manually controlled by the operator to limit or increase feedwater as
2 necessary to maintain feedwater inventory and cooldown rate. A pushbutton is provided for each control
valve to allow the individual valve to be placed in either an automatic level control mode or in a manual
5 mode of operation. In automatic, the valves are positioned and controlled by the automatic level control.
5 Independent level transmitters are utilized in the automatic control system. Upon loss of all four reactor
coolant pumps, such as during blackout conditions, the level control setpoint is automatically raised to
promote natural circulation in the Reactor Coolant System.

Although not normally aligned or utilized in the safety related function of the EFW System, a redundant, separate path of EFW to the steam generators and means of controlling EFW pump discharge flow is provided by startup control valves FDW-35 and FDW-44. This additional flow path is not required for normal EFW System function, but may be aligned manually if necessary or desirable during normal startup or cooldown. Normally closed motor operated valves FDW-38, FDW-47, FDW-374, and FDW-384 can be opened from the control room to provide this additional flow path if required. Control valves FDW-35 and FDW-44 are modulated by control signals based on steam generator water levels by the ICS. As in the case of control valves FDW-315 and FDW-316, the level control setpoint is automatically raised upon loss of all four reactor coolant pumps to promote natural circulation in the Reactor Coolant System.

The steam supply for the EFW pump turbine is provided from either main steam line. Valve MS-93 in the common supply to the turbine will fail open upon loss of station air or power to the normally energized solenoid valve. Upon receipt of a manual or automatic start signal, the solenoid valve will de-energize and immediately start the turbine.

Sufficient valving is provided to allow isolation and cross-connection as required to select and isolate
water sources and assure system function in the event of various failures. During normal orderly
shutdown as a result of blackout or loss of feedwater, no valve re-alignments or isolation is necessary. All
necessary valves are maintained in normal standby alignment to assure an open flow path for each pump,
2 and to assure piping separation and independence. All manually-operated valves in the piping from the
2 Upper Surge Tanks (UST) to the suction of the EFW pumps are locked open. (Reference 2)

The motor driven EFW pumps require cooling water for continuous operation. Sufficient cooling water is initiated automatically, upon manual or automatic start of motor driven EFW pumps.

Sufficient alarms are provided to alert the operator of conditions exceeding normal limits. Essential plant parameters are annunciated or alarmed by the process computer in addition to specific EFW System alarms as listed below:

1. Motor driven EFW pumps low suction pressure
2. Steam generator low level alarms
3. Hotwell low level alarms
4. UST low level alarms
5. Low motor driven EFW pump cooling water flow
6. Motor driven EFW pump stator winding high temperature
7. Motor driven EFW pump motor bearing high temperature
8. Motor driven EFW pump bearing high temperature
9. Motor cooler excessive leakage
10. Motor driven EFW pump A auto start blocked
11. Motor driven EFW pump B auto start blocked
12. Turbine driven EFW pump auto start blocked

2 13. Motor driven EFW pump A low level start

2 14. Motor driven EFW pump B low level start

8 15. Turbine driven EFW pump turbine lube oil low pressure

8 16. Turbine driven EFW pump turbine oil high temperature

8 17. Turbine driven EFW pump turbine hydraulic oil low pressure

8 18. Turbine driven EFW pump turbine auxiliary oil pump overload

8 19. Turbine driven EFW pump tripped

10.4.7.3 Safety Evaluation

Feedwater inventory is maintained in the steam generators following reactor shutdown by one of the following methods listed:

1. Either of the two main feedwater pumps is capable of supplying both steam generators at full secondary system pressure.
2. The two EFW motor driven pumps are capable of supplying both steam generators at full secondary system pressure.
3. The single EFW turbine driven pump is capable of supplying both steam generators at full secondary system pressure.
4. Alternate EFW supplies may be available from the EFW Systems of the other Units, capable of supplying both steam generators at full secondary system pressure.
5. The hotwell and condensate booster pump combination has discharge shutoff head of approximately
8 620 psia. Three pairs of pumps are provided. If required, the Turbine Bypass System or the ADVs

can be used to reduce secondary system pressure to the point where one hotwell and condensate booster pump combination can supply feedwater to both steam generators.

6. The Auxiliary Service Water System may be used to maintain steam generator water inventory following steam generator depressurization to remove decay heat in the long term.
7. The SSF Auxiliary Service Water System is capable of supplying both steam generators of all three units at full secondary system pressure.

A sufficient depth of backup measures is provided to allow steam generator water inventory to be maintained by any of the diverse methods listed above. Although redundancy and diversity is provided in the listed measures, the EFW System has been designed with special considerations to enable it to function when conventional means of feedwater makeup may be unavailable.

Redundancy is provided with separate, full capacity, motor and turbine driven pump subsystems. Failure of either the motor driven pumps or the turbine driven pump will not reduce the EFW System below minimum required capacity. Pump controls, instrumentation, and motive power are separate in design. Separate piping subsystems include redundant hotwell, upper surge tank, and condensate supply piping, aligned individually to the separate pump trains. Cross-connection is provided, however, to allow a subsystem to supply all pumps in the event of single failure of a suction piping subsystem. The same design philosophy is included in the discharge piping subsystems.

In order to provide sufficient EFW flow to the intact steam generator to ensure adequate core cooling,
and under a main steam or main feedwater break in OTSG A with a single active failure of motor driven
emergency feedwater pump B train, the operator must manually close the motor operated isolation valve
6 (FDW-372) or the flow control valve FDW 315 on OTSG A. This action can be done from the Control
Room. The same is true for OTSG B and motor driven emergency feedwater Pump A. The operator
has sufficient Control Room indication of steam generator level and pressure and would immediately be
aware of such a situation.

Concurrently, the operator would monitor the intact steam generator to assure adequate inventory and secondary heat removal via either Main Feedwater or Emergency Feedwater Systems.

In the event of a postulated break in the Main Steam or Main Feed System, coupled with a single active failure of either one of the three emergency feed water pumps, sufficient flow will occur to provide adequate core cooling.

5 With a postulated break associated with the 'A' OTSG and a failure of the 'B' motor driven emergency
5 feedwater pump, the normal feedwater system will be isolated to both steam generators and the TDEFWP
5 will be inhibited from automatically starting. The TDEFWP can be manually started by placing its
7 control switch to RUN.

5 With a postulated break associated with the 'A' OTSG and an active failure occurs with the flow control
5 valve (FDW-316), the Main Steam Line Break Circuitry must be disabled by the operator to allow
5 emergency feedwater flow alignment through the main feedwater startup control valves to either the main
7 or auxiliary nozzles.

5 In the unlikely event that FDW-315, 316 fail open (on a loss of compressed air and nitrogen), an operator
5 could manually adjust either one of the valves as they are located in the Penetration Rooms which are
5 adjacent to the Control Room.

The spectrum of transients which require EFW system performance for post trip heat removal have been evaluated assuming only one motor driven emergency feedwater pump is available to deliver the necessary feedwater. Any single failure in the three pump-two flowpath EFW system design will not result in only one motor driven EFW pump available, so that this assumption is overly conservative. These analyses verify the acceptability of the Emergency Feedwater System design.

8 The following portions of the system are designed to withstand seismic loading (criteria for seismic loading
8 defined in Chapter 3, "Design of Structures, Components, Equipment, and Systems"):

8 1. Both supply lines from the upper surge tank to the emergency feedwater pumps, including connected
8 branch piping up to and including the first valve which is normally closed or capable of automatic
8 closure when the safety function is required.

8 2. Both discharge lines from the emergency feedwater pumps to the steam generators including piping
8 through the first valve of any connections to these lines.

10.4.7.4 Inspection and Testing Requirements

A comprehensive test program is followed for the EFW System. The program consists of performance tests in the manufacturers' shops, preoperational tests of the system, and periodic tests of the activation logic and mechanical components to assure reliable performance during the life of the unit.

During unit operation, the EFW System is tested by utilizing the recirculation test line to the upper surge tank dome. Pump head and flow is verified utilizing this method.

10.4.7.5 Instrumentation Requirements

Sufficient instrumentation and controls are provided to adequately monitor and control the EFW System. The safety related instrumentation and controls which monitor steam generator level and pressure, automatically start the EFW pumps, and automatically align the supply meet the system requirements for redundancy, diversity and separation. All nonsafety related instrumentation and controls are designed such that any failure will not cause degradation of any safety related equipment function.

9 10.4.8 OTSG CONDENSER RECIRCULATION SYSTEM

9 10.4.8.1 Design Bases

9 The basis of the OTSG recirculation system is to provide a means to control steam generator corrosion
9 during non-operating periods by filling the steam generators, draining the steam generators, and
9 recirculating the water in the steam generators.

9 10.4.8.2 System Description

9 Each unit has one OTSG recirculation pump for both steam generators, as seen in Figure 10-9. This
9 pump is utilized to fill the steam generators, drain the steam generators, transfer water between steam
9 generators, and recirculate the water in the steam generators. The OTSG recirculation pump can take its
9 suction from several points on either steam generator. The recirculation pump is locally controlled in the
9 reactor building. The recirculation pump is isolated during modes 1, 2, and 3 due to the pressure rating of
9 the piping/components.

10.4.9 REFERENCES

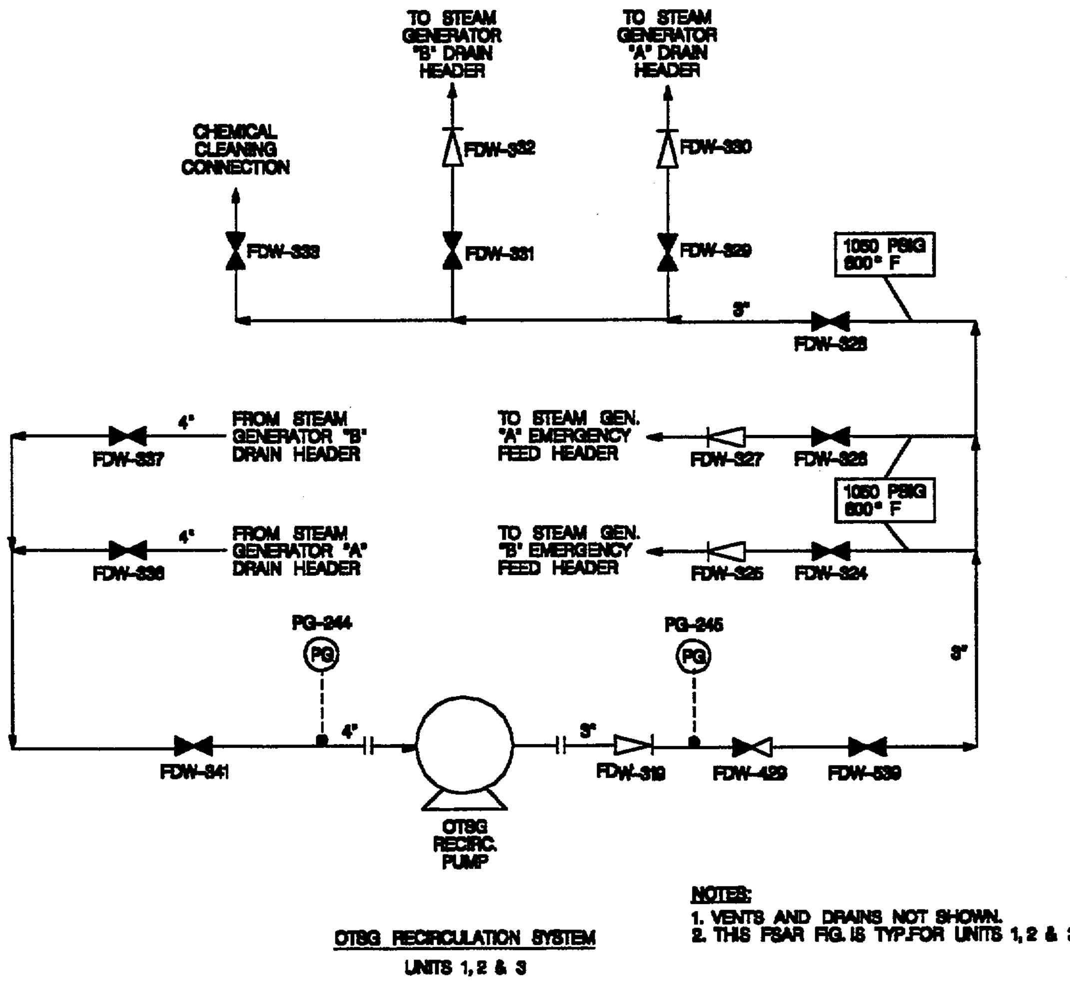
8 1. J. A. Klingenfus (FTI), letter to M. E. Henshaw (Duke), CRAFT2 SBLOCA EFW Flows,
8 November 9, 1998.

2 2. W. O. Parker (Duke) letter to H. R. Denton (NRC), April 3, 1981, page 32.

7 3. ONOE-11376, changes to support multiple unit alignment to the Auxiliary Steam Header.

9 4. Deleted per 1999 Update

THIS IS THE LAST PAGE OF THE CHAPTER 10 TEXT PORTION.



9 Figure 10-9.

9 OTSG Recirculation System

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 11. RADIOACTIVE WASTE MANAGEMENT

2 11.1 DESIGN BASIS

2 The liquid and gaseous radioactive waste management systems will be utilized to reduce radioactive liquid
2 and gaseous effluents such that compliance with the dose limitations of the Selected Licensee
2 Commitments is assured. These dose limitations require that:

2 1. the concentration of radioactive liquid effluents released from the site to the unrestricted area will be
2 limited to 10 times the effluent concentration (EC) levels of 10CFR 20, Appendix B, Table 2;

2 2. the exposures to any individual member of the public from radioactive liquid effluents will not result
2 in doses greater than the design objectives of 10CFR 50, Appendix I;

2 3. the dose rate at any time at the site boundary from radioactive gaseous effluents will be limited to: for
2 noble gases; less than or equal to 500 mrem/yr to the whole body and less than or equal to 3000
2 mrem/yr to the skin; and for iodine-131 and 133, for tritium, and for all radioactive materials in
2 particulate form with half-lives greater than 8 days; less than or equal to 1500 mrem/yr to any organ;

2 4. the exposure to any individual member of the public from radioactive gaseous effluents will not result
2 in doses greater than the design objectives of 10CFR 50, Appendix I; and

2 5. the dose to any individual member of the public from the nuclear fuel cycle will not exceed the limits
2 of 40CFR 190 and 10CFR 20.

9 6. the Solid Waste Management System shall be used in accordance with a Process Control Program, as
9 described in Section 11.4, "Solid Waste Management System," such that compliance with the Selected
9 Licensee Commitments is assured.

11.2 LIQUID WASTE MANAGEMENT SYSTEMS

2

2 11.2.1 DISPOSAL METHODS AND LIMITS

Liquid wastes from the station are disposed of, under continuous radiation monitoring and control, in one of the following three ways depending on the concentration of radioactivity and quantities involved:

8 1. Collected, sampled, analyzed, and discharged directly to the tailrace of the Keowee Hydroelectric
8 Plant if the water is required to be monitored during release. If the water does not require monitoring
8 during release, it is discharged to the Chemical Treatment Pond #3.

8 2. Processed by filtration and/or demineralization, collected, sampled, and analyzed. The filters and/or
8 spent resins are packaged and shipped offsite to an NRC or approved agreement state licensed burial
8 ground. The processed water is discharged directly to the tailrace of the Keowee Hydroelectric Plant
8 if the water is required to be monitored during release. If the water does not require monitoring
8 during release, it is discharged to the Chemical Treatment Pond #3.

8 3. Processed by filtration and/or demineralization, collected, sampled, and analyzed. The filters and/or
8 spent resins are packaged and shipped to various offsite vendor waste processors. The processed
8 water is discharged directly to the tailrace of the Keowee Hydroelectric Plant if the water is required to
8 be monitored during release. If the water does not require monitoring during release, it is discharged
8 to the Chemical Treatment Pond #3.

Liquid waste effluent is diluted, as necessary in the hydroelectric plant tailrace to permissible concentration
9 limits in accordance with Selected Licensee Commitments. Waste releases from the three units are
9 integrated and controlled by process radiation monitors, interlocks, and by the operator so as not to
9 exceed the appropriate station release limits. Where effluents can be released from more than one
9 location, administrative controls are also provided to insure that station limits are not exceeded.

11.2.2 DISPOSAL SYSTEM DESIGN

11.2.2.1 General Description

Liquid wastes are accumulated in storage tanks according to the waste source and expected process train. The Auxiliary Building coolant treatment header has been redesigned to facilitate the processing of liquid wastes from the high activity waste tanks, low activity waste tanks, and the miscellaneous waste holdup
6 tanks in the Radwaste Facility. The liquid wastes are directed to the Radwaste Facility for processing by
6 filtration and/or demineralization to segregate impurities for ultimate disposal as per Section 11.4.2,
6 "System Design and Evaluation." Based on the analysis, water is either reprocessed or released as per
9 Section 11.2.2.2, "Operation." The Liquid Waste and Recycle System is shown in Figure 11-2.

0 In addition, vendor supplied equipment may be utilized to process water and reduce waste volumes.

6 The Interim Radwaste Building (IRB) has the necessary equipment to process liquid waste. However,
9 current operating practice does not make use of these systems. The Radwaste Facility (RWF) systems, as
9 described in Section 11.6.3, "Mechanical Systems," are utilized.

9 When the IRB systems are in use, the IRB floor drains and equipment drains are collected in two sumps.
The floor and low activity drains sump collects floor drains and low activity degassed equipment drains.
9 This sump discharges to the Oconee 3 low activity waste tank in the Auxiliary Building. The floor and
low activity sump is vented to the Oconee 3 vent stack.

9 High activity equipment drains in the IRB are collected in high activity equipment drains sump. Two
9 sump pumps are aligned to transfer the sump contents to the Oconee 3 high activity waste tank in the
9 Auxiliary Building. The high activity equipment drains sump is vented to the suction of the Oconee 3
waste gas compressors via the Oconee 3 waste gas vent header.

9 The Radwaste Facility floor drains and equipment drains are collected in two sumps. The radwaste
9 curbed area sump collects low activity floor drains and low activity equipment drains. Two pumps are
9 utilized to discharge sump contents to the waste monitor tanks in the Radwaste Facility. High activity
9 equipment and floor drains in the Radwaste Facility are collected in the radwaste shielded area sump.
9 Two sump pumps normally transfer the sump contents to the waste feed tank in the Radwaste Facility.

All piping and equipment in contact with reactor coolant are constructed of corrosion-resistant material. This equipment is arranged and located to permit detection and collection of system losses and to prevent escape of any unmonitored radioactive liquid to the environment. Component data are shown in Table 11-6.

The liquid waste discharge header to the Keowee Hydro tailrace is shown in Figure 11-1.

Waste tanks in the IRB and the Auxiliary Building are vented as necessary to the gaseous waste vent
header to provide for filling and emptying without overpressurization or creating a vacuum. In addition,
8 each waste tank is equipped with a relief valve and/or vacuum breaker. Nitrogen is supplied to each waste
collection tank for purging to the Gaseous Waste Disposal System as needed.

Flush water is provided at appropriate locations in the system for flushing of piping and components.

11.2.2.2 Operation

7 Liquid wastes are collected in the Auxiliary Building and are transferred to the Radwaste Facility for
6 processing by filtration and/or demineralization. Although it is not a normal process option, liquid wastes
6 could be transferred to the IRB.

6 Liquid wastes are released from the Decant Monitor Tank, Recycle Monitor Tanks, and/or the Waste
6 Monitor Tanks in the Radwaste Facility. After the liquid is mixed, sampled, and analyzed, a release rate
6 consistent with dilution flow from the Keowee Hydro Station is determined and the radiation monitor
6 alarm set points adjusted to comply with limits specified in Selected Licensee Commitments. The release
6 is controlled from the Radwaste Facility control room and monitored by 1RIA 33. The RIA will
6 terminate a release on a high alarm setpoint by closing LW-131. The release activity in CPM is recorded
6 in the Radwaste Facility Control Room.

6 **11.2.2.2.1 Deleted per 1996 Revision.**

6

11.2.2.3 Liquid Waste Holdup Capacity

9 *The information in this section is not updated and is included for historical purposes only. Potential waste*
9 *generation rates are based on data gathered at ONS for years 1977 and 1978 and are found in "Evaluation*

9 *of Compliance with 10CFR50 Appendix I," June 4, 1976. Actual amounts vary from year to year depending*
9 *on unit operating history. Actual liquid waste generated is reported in the Oconee Annual Effluent Report in*
9 *accordance with SLC 16.11.9.*

7 The liquid waste holdup times are estimated using the following assumptions:

7 1. The potential liquid waste generation rates are as follows (See Table 11-1): Actual liquid waste
7 generated is reported in the Oconee Annual Effluent Report.

(a) Primary System	161,019 ft^3 per year for 3 units
(b) Spent Fuel Pool	26,349 ft^3 per year for 3 units
(c) Cask Decontamination	17,566 ft^3 per year for 3 units
(d) Component Coolant	17,566 ft^3 per year for 3 units
(e) Service Water	58,553 ft^3 per year for 3 units
(f) Decontamination Room	87,828 ft^3 per year for 3 units
(g) Resin Sluice	23,421 ft^3 per year for 3 units
(h) Miscellaneous System Leakage	351,312 ft^3 per year for 3 units
(i) OTSG Tube Leaks	40,140 ft^3 per year for 3 units
(j) LHST	161,019 ft^3 per year for 3 units
TOTAL	944,773 ft^3 per year for 3 units

2. Design holdup capacity equals the contents of the miscellaneous waste holdup tanks, interim evaporator feed tanks, and condensate monitor tanks A and B which is 83,793 gallons for Oconee 1, 2 and 3.

3. The time for filling and discharging the tanks is 6 hours or less.

4. The tanks fill at a linear rate and the contents are discharged when the tanks become full and are sampled.

From the assumptions above the holdup times are:

Oconee 1 and 2 Holdup Time = 5.25 days

Oconee 3 Holdup Time = 11.46 days

6 The Radwaste Facility provides primary holdup and processing having 140,000 gallons of storage capacity.

2

11.3 GASEOUS WASTE MANAGEMENT SYSTEMS

2

2
11.3.1 DISPOSAL METHODS AND LIMITS

2 Gaseous activity is generated by the evolution of radioactive gases from liquids stored in tanks throughout
9 the station. When this gaseous activity is present outside of specific piping systems or tanks, then it is
9 collected and/or routed through various pathways in the plant. Gaseous wastes are disposed of, at a
2 permissible rate, under continuous radiation monitoring or periodic sampling and control, by any of the following methods depending on the concentration of radioactivity, quantities, and source of the material involved:

1. Release of Auxiliary Building ventilation air and Reactor Building purges to the unit vents.
2. Release of Reactor Building purges through high efficiency particulate and charcoal iodine filters to the unit vents.
3. Release of waste gas directly or through high efficiency particulate and charcoal iodine filters to the unit vents.
4. Diversion to waste gas tanks with controlled release after sampling and analysis through the waste gas system high efficiency particulate and charcoal iodine filters to the unit vents.
5. Release of Radwaste Facility HVAC and process exhaust.

9 6. Release of Penetration Room Ventilation Air to the unit vents

9 7. Release of the Hot Machine Shop Ventilation Air through exhaust filters to the outside environment

9 8. Release of the CSAE (Condenser Steam Air Ejector) air to the unit vents

7 The tank vent system is processed through carbon and high efficiency particulate filters.

Gaseous wastes are released from the station at a controlled rate so that permissible concentration limits for Unrestricted Areas will not be exceeded at the Exclusion Area boundary, when averaged over a year in
2 accordance with the requirements of the Selected Licensee Commitments. The concentrations at the boundary are determined after applying appropriate dilution factors derived from on-site meteorological
2 studies (Section 2.3, "Meteorology").

Waste releases from the three units are integrated and controlled by process radiation monitors, interlocks, and by the operator so as not to exceed the appropriate station release limits. Where effluents can be released from more than one location, administrative controls are also provided to insure that station limits are not exceeded.

11.3.2 DISPOSAL SYSTEM DESIGN

11.3.2.1 General Description

All components in the Auxiliary Building and IRB that can contain potentially radioactive gases are vented to a vent header. The vent gases are subsequently drawn from this vent header by one of two waste gas compressors or a waste gas exhauster. The waste gas compressor discharges through a waste gas separator to one of two waste gas tanks. The waste gas tanks and the waste gas exhauster discharge to the

unit vent after passing through a filter bank consisting of a prefilter, an absolute filter, and a charcoal filter. A flow diagram of this system with the necessary instrumentation and controls for operation is
9 shown in Figure 11-3. Component data are shown in Table 11-6. The venting of RWF components
9 that contain potentially radioactive gases is discussed in Section 11.6.3.6, "Heating Ventilation and Air
9 Conditioning."

Oconee 1 and 2 share a Gaseous Waste Disposal System. Oconee 3 has a separate Waste Gas Disposal System, which can be interconnected to the Gaseous Waste Disposal System for Oconee 1 and 2 through double isolation valves between the vent headers. These are normally operated separately, but may be tied together to facilitate maintenance of either of the systems.

The purpose of the Gaseous Waste Disposal System is to:

1. Maintain a non-oxidizing cover gas of nitrogen in tanks and equipment that contain potentially radioactive gas.
2. Hold up radioactive gas for decay.
3. Release gases (radioactive or non-radioactive) to the atmosphere under controlled conditions.

11.3.2.2 Operation

One waste gas compressor is normally in continuous operation with the other compressor in a standby condition. The waste gas compressor takes suction on the vent header and normally discharges into waste gas tank "A" which is used as a surge tank. The vent header pressure control operates a bleedback valve (GWD-1) allowing a continuous circulation of gas through the vent header. As liquid storage tanks connected to the systems are filled, the excess gas is stored in the waste gas tank. As liquid storage tanks are emptied, gas flows from the waste gas tank back into the vent header. As waste gas tank "A" is filled, the inlet valve on waste gas tank "B" (GWD-3) is opened and waste gas tank "A" inlet valve (GWD-2) is closed. The gas in waste gas tank "A" is allowed to bleed back into the vent header and is directed into waste gas tank "B" by the waste gas compressor until the pressure in waste gas tank "A" is at the desired operating pressure. The valves are then repositioned to utilize waste gas tank "A" as a surge tank and waste gas tank "B" for radioactive decay. Gas in waste gas tank "B" is sampled for laboratory analysis to determine the permissible release rate or need for holdup for radioactive decay.

Release of gas from the waste gas tanks to the unit vent is controlled by the waste gas tank outlet valves
2 GWD-4 and GWD-5. The volume of gas discharged to the unit vent is recorded in the Control Room
2 and is documented on the Gaseous Waste Release (GWR) permit governing the release. Monitoring of
the gas discharged to the unit vent for radioactivity is provided by a radiation monitor which, on a high
2 radiation signal, will close the valves through which the gas is being discharged. In the event that the
2 applicable radiation monitor is not available for service, two independent samples of the gas to be released
2 are collected. The two samples independently verify the gas activity and serve as the basis for determining
2 the gaseous waste release rate.

The waste gas exhauster is used when large volumes of gas containing little or no radioactivity are available for release to the unit vent. The waste gas exhauster and its isolation valves are interlocked to trip the exhauster and close the isolation valves in case of a high radiation level in the line going to the unit vent. The waste gas exhauster does not normally operate and is normally valved off by the manual valve upstream of GWD-6. Therefore, no unintentional release of significant activity is possible through this line.

9 Most of the Gaseous Waste Disposal system is located in the Auxiliary Building. Some equipment is
9 located in the Interim Building, namely Interim Waste Gas Decay Tanks 1C, 1D, and 3C and their

9 associated piping and valves. The control of the discharge flow for these tanks is similar to that for tanks
9 "A" and "B" listed above, through the appropriate valves.

3 All indication and controls for this system are located in the Control Room.

11.3.2.3 Gaseous Waste Holdup Capacity

9 *The information in this section is not updated and is included for historical purposes only. Potential waste*
9 *generation rates are based on data gathered at ONS for years 1977 and 1978 and are found in "Evaluation*
9 *of Compliance with 10CFR50 Appendix I," June 4, 1976. Actual amounts vary from year to year depending*
9 *on unit operating history.*

9 The estimates of potential gaseous waste holdup times are based on the following assumptions:
9 (Assumptions and volumes are approximate and historical in nature) note that actual gaseous waste
9 activity that is released is reported in the Oconee Annual Effluent Release Report.

1. An annual waste gas generation rate of 131,400 ft^3 is evolved from three units (Table 11-1). Oconee 1, 2, and 3 contribute 43,800 ft^3 each per year.
0 2. Four waste gas tanks located in the Auxiliary Building and three waste gas tanks located in the Interin
0 Radwaste Building provide holdup capacity for Oconee 1, 2, and 3.
3. Holdup capacity is as follows:

Auxiliary Building	Oconee 1 & 2	Oconee 3
Auxiliary Building Tanks (ft^3)	2200	2200
0 Interin Radwaste Building Tanks (ft^3)	2104	1052
Total Storage Volume	4304	3252

4. The times for filling and venting the waste gas tanks are negligible.
5. The waste gas tanks are initially filled with nitrogen at 10 psig and 100°F. The tanks may be filled to
2 approximately 85 psig and 100°F.

2

11.3.3 TESTS AND INSPECTIONS

Each process radiation monitoring channel will be functionally tested and calibrated periodically to verify proper operation of components and to insure that the desired detector sensitivities are maintained.

A signal generator located within the process monitor panel will be used to check the alignment of electronic modules. After the electronic alignment is completed, a remote operated calibration source is actuated to determine proper functioning of the detector.

The flow measuring instrument and controls associated with the gaseous waste effluent lines will be calibrated periodically to insure proper accuracy, measurement, and control of radioactivity releases from the station.

Efficiency of the particulate filters is determined in the factory, as well as in-place, in accordance with USA DOP (Dioctyl Phtholate) test method and UL standard 586. DOP smoke is introduced upstream of the filter and the quantity detected downstream of the filter is measured. This test is conducted at full rated flow capacity, minimum acceptable test efficiency for the particulate filter is 99.97 percent. The difference between factory and in-place tests is the test duration time: 30 seconds and 2 minutes, respectively.

Efficiency of the iodine filter is determined by two different methods in the factory. One employs I_2-131, I_2, and CH_3I; the other uses refrigerant-11.

In place testing of both the particulate and iodine filters are done in accordance with ANSI N-510.

11.3.3.1 Test with Iodine

The filter shall remove at least 99.9 percent of molecular iodine-131 (I_2-131) in the presence of a gaseous concentration of 50 mg per m^3 of non-radioactive molecular iodine (I_2) plus 5 mg per m^3 of non-radioactive methyl iodide (CH_3I). This performance level is maintained until the amount of non-radioactive I_2 having reached the test unit is equivalent to 200 gm in the full scale system. Following this loading, feeding of non-radioactive I_2 and CH_3I is halted, and air at 70 percent relative humidity and 150°F is drawn through the test unit at its rated flow for two hours. The integrated I_2-131 removal efficiency for the test unit, including both iodine feed and elution periods, shall be no less than 90.0 percent. The I_2-131 feed periods is between 10 and 100 microcuries per gram of non-radioactive I_2 feed.

The filter is required to remove at least 99.0 percent of methyl iodide-131 (CH_3I-131) in the presence of a gaseous concentration of 50 mg per m^3 of non-radioactive methyl iodide (CH_3I). This performance level is maintained until the amount of CH_3I having reached the test unit is equivalent to 200 gm in the full scale system. Following this loading, feeding of I_2 and CH_3I is halted, and air at 70 percent relative humidity and 150°F is drawn through the test unit at its rated flow for two hours. The integrated efficiency in the removal of CH_3I-131 by the test unit, including both feed and elution periods, is required to be no less than 65 percent. The CH_3I-131 activity during CH_3I-131 feed periods is between 10 and 100 microcuries per gram of non-radioactive CH_3I feed.

11.3.3.2 Test with Refrigerant-11

Refrigerant-11 is injected into an air flow of 333 cfm upstream of the filter until the concentration is 50 ppm. After 2 minutes, the refrigerant-11 concentration downstream of the filter is required to be less than 0.1 ppm.

Field tests for efficiency will be performed using refrigerant-11 only. The system will be operating at rated flow. Refrigerant-11 is introduced upstream of the filter to produce an R-11 concentration of 50 ppm. With an upstream concentration of 50 ppm and a test of 2 minutes, the maximum allowable downstream concentration is 0.1 ppm.

11.4 SOLID WASTE MANAGEMENT SYSTEM

11.4.1 DESIGN BASES

9 As per Selected Licensee Commitment 16.11-5, radioactive wastes shall be processed and packaged to
9 ensure meeting the requirements of 10CFR Part 20, 10CFR Part 71, and Federal and State regulations
9 governing the disposal of solid radioactive wastes.

11.4.1.1 Solid Waste Activities

6 Solid radioactive wastes are as described in Section 2 of the Oconee Nuclear Station 10CFR Part 61
6 Waste Classification and Waste Form Implementation Program. This activity is not released to the
environment and influences only the shielding required to meet criteria stated in Section 12.3.1, "Facility
Design Features."

11.4.1.2 Disposal Methods and Limits

Solid wastes will be packaged to meet applicable regulations and shipped in accordance with DOT
6 regulations to a processor or directly to either an NRC or state licensed disposal facility.

6 Disposal of slightly contaminated materials within the Company Controlled Area has been approved by
6 the State of South Carolina and the NRC. Prior to disposal onsite, the waste is analyzed and confirmed
6 to have acceptably low radionuclide concentrations. Permission is then obtained from the proper agencies
6 per 10CFR20.2002 requirements. Each application for disposal is evaluated and approved on a case by
6 case basis as determined by material quantities, material type, disposal methods, and radionuclide
6 concentrations.

11.4.2 SYSTEM DESIGN AND EVALUATION

The Solid Waste Disposal System provides the capability to package solid wastes for shipment to an offsite NRC or approved agreement state licensed burial facility.

6

The disposal of the powdered resins may be accomplished by backwashing the resins from the filter
7 elements to a sump in the Turbine Building and then to the Resin Recovery System for processing. The
7 resin is allowed to settle to the bottom of the Backwash Receiving Tanks (BRT) in the Radwaste Facility.
The excess water in the BRT is decanted to the Decant Monitor Tank for sampling and release to the
7 environment. The powdered resins may then be used for processing waste. The resins are then prepared
6 for shipment to a processor or directly to either an NRC or state licensed disposal facility

6 Bead resins can be sluiced to an approved shipping container where they are prepared for shipment to a
6 processor or directly to either an NRC or state licensed disposal facility.

6 The Process Control Program Manual describes operation of the Solid Radioactive Waste System such
6 that the final product of solidification or dewatering meet all shipping and transportation requirements
6 during transit and meet disposal site requirements when received at the disposal site.

6 Low level trash such as dry active waste and spent filters are prepared for shipment to a processor or
6 directly to either an NRC or state licensed disposal facility.

6

11.4.3 REFERENCES

1. B. J. Youngblood (NRC) letter to H. B. Tucker (Duke) dated May 2, 1986.

11.5 PROCESS AND EFFLUENT RADIOLOGICAL MONITORING AND SAMPLING SYSTEMS

11.5.1 DESIGN BASES AND EVALUATION

Radiation monitoring of process systems provides early warning of equipment, component, or system malfunctions, or potential radiological hazards. The Process Radiation Monitoring System includes alarms, indications, and recording of data in the Control Rooms. In some cases automatic action is taken upon an alarm condition; in others the alarm serves as a warning to the operator so that manual corrective action can be taken. Radioactive liquid and gaseous waste effluents, particularly, are monitored, coordinated between Control Rooms, and controlled to assure that radioactivity released does not exceed 10CFR 20 and 10CFR 50 Appendix I limits for the station as a whole.

The sensitivity and the ranges of the detectors have been coordinated with system and environmental dilution factors to assure that releases due to normal, transient, and accident conditions will be monitored and that normal releases will not exceed permissible concentrations. The release of radioactive waste will generally be on a batch basis. Waste releases will also be integrated and recorded. Interlocks are provided to terminate any release of liquid or gaseous waste if a pre-set radiation level is reached. The monitoring and controls exerted by the Process Radiation Monitoring System and the operator during the release will also be supplemented by manual sampling, laboratory analysis, and counting prior to release.

Various detectors are also shielded against ambient background radiation levels that would exist in their location due to normal, transient, or accident conditions, so that accurate readings of radioactivity will be obtained.

The process monitors have been given a primary calibration with the particular radionuclides that they are expected to monitor. Their energy response has been determined as an aid in measurement of other
9 radionuclides that may also be encountered. A calibration source, related to primary calibration at the factory, is supplied with the system. The sources are held by Radiation Protection or I & E and used
0 periodically to calibrate the detector. A check source is used only to verify that the detector is functional. Spectrometer grade amplifiers have been supplied with all of the sodium iodide scintillation (NaI) detectors so that they can be used with a gamma analyzer for the identification of the specific radionuclides being monitored.

Monitors are also provided on various non-radioactive cooling water systems to detect leakage from normally radioactive systems due to any component failures and thus prevent their accidental release to the environment. In addition to the manual sampling of waste prior to release, mentioned above, the measurement of radioactivity in other process fluids is also supplemented by manual sampling, laboratory
2 analysis, and counting. This is particularly necessary for beta-emitting radionuclides such as tritium.

11.5.2 DESCRIPTION

The radiation monitoring equipment indications and alarms are located in the Control Rooms from which the systems being monitored are operated. Radiation monitor indications for liquid waste disposal and the Radwaste Facility vent effluents are displayed in the Radwaste Facility Control Room. Indications
0 for unit vent effluents can be displayed in both Control Rooms. Outputs from all process monitor
9 channels are recorded in the RIA computer system or on multipoint recorders. Control Room
0 annunciation of high radiation level is provided for each channel. Most detector assemblies are equipped with a Control Room operated check source.

Table 11-7 lists the process radiation monitors and gives the following information:

1. Channel Number and Function - A Radiation Indicating Alarm (RIA) number has been assigned to each detector. Monitors serving the same function have the same number. Prefix numbers indicate
9 the unit on which the detector is used. No prefix number indicates that the RIA is shared between
9 two or more units. The function shows the system in which the monitor is employed.

2. Type of Detector - The standard detector type identification is given followed by the size of the crystal or the length of the detector. The lead shield thickness which has been applied to obtain the sensitivities indicated is also given.

3. Sensitivity - Monitor sensitivities are indicated in terms of background equivalent concentrations and count rate for the radionuclides listed. Background equivalent information shown in the table defines the ability of the monitor to detect the indicated radionuclide concentrations inside the sampler at a count rate that is equal to that resulting from a gamma field outside the sampler. The lead shielding
9 is designed to reduce the count rate resulting from Cobalt-60 gammas in order to obtain the
9 sensitivities shown. This information is taken from the manufacturer's technical manuals.

4. Range - Readout range of monitoring instrumentation, upper range limits, and range overlap between different detectors monitoring the same sample are indicated.

The following is a description of the various applications of these monitors as they are applied to systems:

4 1. 1,2 and 3RIA16 and 17 detectors monitor the A and B Main Steam line piping respectively for the
4 presence of radioactivity in the process steam. The primary purpose for these monitors is to aid in
4 the detection of a steam generator primary to secondary leakage fault. Readout and alarms for these
4 monitors are located in the associated control rooms.

9 2. RIA-31 monitors gross gamma from the Low Pressure Service Water outlets of the A and B Low
4 Pressure Injection Decay Heat Coolers of Units 1, 2 and 3. Samples from the cooler outlets are
4 sequentially automatically valved and monitored. Sample valve scan rate is adjustable from the Unit
4 1 SCADA terminal. Unit 1 control room contains the main control terminal for the monitor. The
4 output from the radiation monitor is indicated in all three control rooms. Alarms are also provided in
4 the control rooms. The monitor is located inside the turbine building and is shielded to function
4 during a loss of coolant accident, including 100 percent release of fission gases inside the Reactor
4 Building. The monitor is provided to supplement indications from 1, 2 and 3RIA-35.

4 3. RIA-32 can monitor air from up to 12 locations and 3RIA-32 can monitor air from up to 6 locations,
each within the Auxiliary Building for early detection and location of equipment malfunctions. They also are designed to warn personnel of the presence of radiological hazards. Each monitor incorporates a sample pump that continuously draws samples through a three-way valve manifold at
2 the detector. Sample valves are sequenced by the RIA computer system to direct individual samples
2 to shielded beta sensitive detectors. Detector outputs are logged by the RIA computer system. Loss
2 of sample flow is annunciated in the Control Rooms as a fault alarm detector.

2 Additionally, RIA-32 and 3RIA-32 are designed to monitor the discharge from the respective units
2 penetration room fans. Manually-selectable sample points permit detection of gaseous activity in the
2 Penetration Room resulting from Reactor Building design leakage following a Reactor Coolant
2 System failure and subsequent release of fission gases into the Reactor Building.

9 4. RIA-33 is used to monitor total liquid waste effluent from the station. Loss of sample flow is
0 annunciated in the Radwaste Facility Control Room. Interlocks from this monitor automatically
2 terminate a release at preset levels.

9 5. 1RIA-35, 2RIA-35, and 3RIA-35 continuously monitor samples of LPSW for gross gamma in the
9 main LPSW discharge headers from the Auxiliary Building. The main headers are monitored since
9 they can contain radioactive leakage from normally radioactive systems due to component failures.

9 Upon any indication of radioactivity in the effluent, the component suspected of leaking may be
9 individually isolated thereby allowing repair of components. The detectors are located inside the
9 Turbine Building. They are shielded to function in the presence of increased background from a Loss
3 of Coolant Accident. Loss of sample flow is annunciated in the appropriate Control Room.

6. RIA-37 and RIA-38 monitor waste gas effluent from Oconee 1 and 2. One instrument channel using
9 a plastic beta scintillation detector (RIA-37) and one instrument channel using a Geiger-Mueller
9 (G-M) tube (RIA-38) provide the dynamic range indicated on Table 11-7. This range covers normal and abnormal operating conditions with overlap as indicated. Interlocks from these monitors automatically terminate release at preset levels. 3RIA-37 and 3RIA-38 are functionally identical and serve the same purpose for Oconee 3. These monitors are shown on Figure 11-3.

9 7. RIA-39 for Units 1 and 2, and 3RIA-39 for Unit 3, monitor Control Room ventilation using beta sensitive detectors (Section 9.4.1.1, "Design Bases"). Samples of Control Room air are continuously pumped through shielded samplers. Loss of sample flow is annunciated in the appropriate Control Room.

8. 1RIA-40, 2RIA-40, and 3RIA-40 monitor condenser air ejector off gas effluent to each unit vent
7 (Section 10.4.2, "Main Condenser Evacuation System") to detect activity in the steam system
2 resulting from a steam generator tube leak. In addition to this protection, 1RIA-16 and 1RIA-17 are
2 located adjacent to the main steam headers. For Oconee 2 and 3, this monitoring function is served
2 by 2RIA-16, 2RIA-17, 3RIA-16, and 3RIA-17, respectively.

9 9. RIA-41 for Units 1 and 2, and 3RIA-41 for Unit 3, monitor ventilation air in both Spent Fuel Buildings using beta sensitive detectors (Section 9.4.2.1, "Design Bases"). Samples of Spent Fuel Building air are continuously pumped through shielded detectors. Loss of sample flow is annunciated in the appropriate Control Room.

9 10. RIA-42 for Units 1 and 2, and 3RIA-42 for Unit 3, monitor recirculated cooling water return from Auxiliary Building for gross gamma activity.

9 11. 1RIA-43, 1RIA-44, 1RIA-45, and 1RIA-46 monitor Oconee Unit 1 vent for radioactive air
9 particulates, iodine, and gas. A vent monitor incorporates a sample nozzle, a pumping system, and
0 four detector channels. The pump supplies samples to an air particulate monitor (moving filter
0 paper), a fixed charcoal filter that is monitored for iodine, and to two gas monitors. The pump also
0 draws a portion of the sample through an Iodine cartridge and filter paper for effluent analysis. Air
9 particulates are detected by monitoring a moving filter paper with a plastic beta scintillator (1RIA-43).
9 Iodine is monitored with a NaI scintillator (1RIA-44) monitoring a selected gamma energy range.
9 Gaseous activity is detected by a plastic beta scintillator (1RIA-45) for normal ranges. A cadmium
9 telluride solid state detector (1RIA-46) is used in a separate instrument gas channel to extend the dynamic range of the system. Sensitivity and overlap of the gaseous monitoring ranges are indicated in Table 11-7. Collection efficiency for the air particulate filter is 99 percent for particles 0.5 micron and larger. The activated charcoal cartridge type filter has a rated collection efficiency of at least 90 percent for radioiodine in forms anticipated.

Malfunctions involving loss of sample flow and depleted, torn, or clogged filter paper are alarmed in the Control Room.

For Oconee 2 and 3, this monitoring function is served by 2RIA-43, -44, -45, -46, and 3RIA-43, -44,
2 -45, -46, respectively.

Interlocks from the gas monitors automatically terminate a Reactor Building purge and close the
7 purge isolation valves on high radiation level. These monitors are shown on Figure 6-4.

4RIA-45 and 4RIA-46 monitor the Radwaste Facility HVAC for noble gas. Particulate and radioiodine activity are continuously sampled by a filter paper and charcoal cartridge sampling
0 arrangement. The sampling filter paper and charcoal cartridge are periodically replaced and analyzed

0 to quantify and qualify radioactivity present in the HVAC system. Noble gas activity is detected by a plastic beta scintillator for normal ranges. A G-M tube is used in a separate instrument channel to extend the dynamic range of the system. Sensitivity and overlap of the gaseous monitoring ranges are indicated in Table 11-7.

0 a. 1RIA-47, 1RIA-48, 1RIA-49, 1RIA-49A and associated equipment make up the Reactor Building Airborne Activity Monitoring System for Oconee 1. The equipment provided is
2 functionally identical to that described for the vent monitors except that a separate Iodine
2 cartridge and filter paper are not available for effluent analysis. For Oconee 2 and 3, this
2 monitoring function is performed by 2RIA-47, -48, -49, 49A, and 3RIA-47, -48, -49, 49A,
2 respectively. On high radiation level, interlocks from the gas monitors automatically close the Reactor Building sump line isolation valves.

12. 1RIA-50 monitors Oconee 1 Component Cooling System for gross gamma using a NaI scintillator (Section 9.2.1.7, "Leakage Considerations"). Sample flow loss is alarmed in the Control Room. For
2 Oconee 2 and 3, this monitoring function is performed by 2RIA-50 and 3RIA-50, respectively.

9 13. RIA-53 is designed to monitor airborne effluent from the Interim Radwaste Building. One
9 instrument channel using a plastic beta-scintillation detector provides the range indicated in
9 Table 11-7. This range covers normal operating conditions. Interim Radwaste Building particulate
9 and radioactive gas constituents are continuously sampled by a filter paper and charcoal cartridge
9 sampling arrangement adjacent to the RIA-53 skid. The particulate and iodine sampling media are
9 periodically replaced and analyzed to qualify and quantify radioactivity present on the media.

3 14. RIA-54 monitors the Unit 1 and 2 Turbine Building sump and stops pumps during loss of power or
2 high activity. 3RIA-54 monitors the Unit 3 Turbine Building sump and stops pumps when high
2 radioactivity levels are detected.

3 15. 1RIA-56, 2RIA-56 and 3RIA-56 are designed to monitor gross gamma activity in each unit vent stack. The detector is an ion chamber located on the vent stack with the readout in the control room. The monitor provides very high range monitoring capabilities for gaseous effluents exiting the unit vent under accident conditions.

3 16. 1, 2, 3RIA-57 and 58 are designed to monitor gross gamma activity in each unit containment
2 building. These post-accident monitors are coaxial ion chambers with readouts in each control room.
9 The monitors are located in the east and west penetration room associated with each unit. 1, 2, and 3RIA-58 have recorders in the Control Rooms.

3 17. The Hot Machine Shop Vent particulate and radioiodine constituents are continuously sampled by a filter paper and charcoal cartridge sampling arrangement. The sampling arrangement is periodically replaced and analyzed to quantify and qualify radioactivity present on the filter paper and/or cartridge. Because of the type of work conducted in the Hot Machine Shop, and because of the location of the Shop to the Auxiliary Building (and its associated ventilation system), noble gas activity is not released via the Hot Machine Shop vent. Therefore, noble gas monitoring capability is not required in the Hot Machine Shop.

4

11.6 RADWASTE FACILITY

11.6.1 GENERAL DESCRIPTION

11.6.1.1 Safety Evaluation

The radwaste facility was evaluated under a 10CFR 50.59 safety evaluation and was found not to involve
9 an unreviewed safety question. In accordance with 10CFR 20.305, pursuant to 10CFR 20.302 (now
9 addressed in 10CFR 20.2004, pursuant to 10CFR 20.2002), Duke requested NRC approval to operate a
9 low-level radioactive waste incinerator, discussed in Section 11.6.3.3, "Volume Reduction and
9 Solidification System," under the ONS Operating License and Technical Specifications (Reference 1).
The NRC transmitted their safety analysis (Reference 2) which concluded that operation of the incinerator would not diminish the safe operation of ONS nor present an undue hazard to public health and safety.

11.6.1.2 Site Characteristics

The site is located south of the Unit 3 Turbine and Auxiliary Buildings. The yard grade elevation in this
6 area is about 796 feet (MSL). Approximately 80 ft. southeast of the facility the yard fill slopes downward
at 2 to 1 (horizontal to vertical) to original ground about 55 ft. below.

The test borings encountered a profile of materials consisting from the ground surface of fill residual soil, partially weathered rock and finally rock or refusal materials. The thickness of fill varied from 18 to just over 70 feet within the proposed facility. The fill soils classify primarily as micaceous silty sands with included clayey layers of low to moderate plasticity.

The fill consistency based on the standard penetration test is loose to dense. The fill appears to be relatively well compacted overall based on penetration resistances. The standard penetration resistances range from less than 5 to greater than 40 blows per foot with values predominantly between 21 and 30 blows per foot.

Below the fill soils, the residual materials weathered from the parent bedrock were encountered. The residual profile consists of a variable thickness of soil underlaid by partially weathered rock. The residual soils primarily are silty sands or sandy silts. The standard penetration test values range from 4 to over 100 blows per foot.

Beneath the fill and residual soils, the test borings encountered refusal materials at depths of 30 to 85 feet below the present surface. The nature of the refusal materials was investigated by rock coring procedures. The rock classified as mica-gneiss.

11.6.1.3 Facility Description

9 The Radwaste Facility is designed to process liquid and solid radioactive wastes. The wastes are separated
9 into clean water and concentrated contaminants. The concentrated contaminants are prepared for
9 disposal and the clean water is discarded or recycled for use in the station. The wastes consist of
miscellaneous liquid waste (radioactive equipment drains and floor drains, etc.) reactor coolant, powdered resin, and miscellaneous radioactive trash (gloves, paper, etc.)

9 Liquid wastes are processed by an appropriate combination of equipment (filter, demineralizer, and/or
evaporator) in the Liquid Waste and Recycle System. (The evaporator is in a state of 'dry layup' and is

9 not in use.) Contaminants collected by the demineralizers and filters are sent to the Dewatering System.
9 Boric acid concentrated from reactor coolant by the evaporator are reused or sent to the Solidification
System as are the waste concentrates.

9 Powdered resin used in the Condensate Polishing Demineralizers are collected and monitored in the Resin
6 Recovery System. The resin can be used to process water from the LW System and/or the Laundry Hot
6 Shower Tanks. Excess water will be removed from contaminated resin and the resin sent to the Volume
9 Reduction System or vendor supplied liners for dewatering. The Liquid Waste and Recycle System is
9 shown in Figure 11-2.

6 The Volume Reduction System (in dry layup) incinerates combustible wastes. The dried product (ash &
salts) and wet wastes will be packaged to meet Federal and State regulations.

11.6.1.4 QA Condition Classifications and Inspection Program

11.6.1.4.1 Perspective

Duke Power Company's Quality Assurance program covers four QA conditions. Quality Assurance Condition 2 (QA 2) applies to radwaste systems and follows the guidance of Regulatory Guide 1.143. Regulatory Guide 1.143 lists systems to which it applies but does not contain criteria for determining applicability.

The criteria herein adopted for the application of QA 2 are based on the "as low as reasonably achievable" (ALARA) concept of radiation protection and generally relate to routinely expected occurrences. The criteria generally result in determinations which are consistent with Regulatory Guide 1.143.

11.6.1.4.2 General Criteria

An item or activity is ALARA related and a QA program is applied if:

a. Functional unavailability, lack of effectiveness, or non-catastrophic failures impair the ability to meet the ALARA objective for effluent releases.

b. Require routine maintenance or repair of anticipated failures would cause excessive or easily avoidable occupational exposure.

11.6.1.4.3 Implementation

a. Eliminating pressure boundary leakage of ALARA related piping systems (delineated on flow diagrams as Class E) is an ALARA related function, but pipe hangers and supports do not perform an ALARA related function because they are provided to prevent gross failure rather than leakage. Experience has shown that conventional power piping has a very low rate of gross failure but leakage is not unusual. Therefore, pipe hangers and supports are not QA Condition 2.

b. The pressure boundary of piping systems with only occasional radioactivity, very low radioactivity, and drains are not ALARA related. Generally, this applies to closed loop cooling and process steam, streams normally releasable without treatment and floor drains.

c. Equipment, parts, and components not part of an ALARA pressure boundary are functionally ALARA related if their failure would prevent the system from performing its intended function greater than 10% of a calendar quarter (about 10 days). Since most electrical equipment and small mechanical equipment can be repaired in this time, they are generally excluded.

d. Only the containment of leaks and spills within the structure is an ALARA related function which requires a QA 2 program by these criteria. Therefore, a QA 2 program will be applied to the "Bathtub Portion" of the radwaste facility structure.

11.6.2 STRUCTURES

11.6.2.1 Description of Building

6 The Oconee Radwaste Facility consists of two separate adjoining structures, separated by a 3 inch
6 expansion joint, both supported by poured in place reinforced concrete mats. One structure is primarily
of reinforced concrete construction with structural walls serving also as shielding for radioactive
6 components or materials. The other structure is primarily of braced structural steel construction with
floors of reinforced concrete on metal deck and conventionally formed reinforced concrete columns and
6 floors supporting large tanks. Exterior walls are insulated metal siding on steel girts. Interior walls are
gypsum wallboard on metal studs and concrete masonry.

11.6.2.2 Design Bases

The structures are modeled as space frames using the McDonald Douglas version of ICES STRUDL, a structural design language computer program. The two dimensional finite element capabilities of STRUDL are used to represent walls and slabs while one dimensional beam elements are used for beams and columns. The supported points of the model have spring stiffnesses representing the force-deflection relationship of the underlying soil, thus differential settlement is accounted for. A modal and shock spectrum analysis was performed using the capabilities of the STRUDL DYNAL feature of the STRUDL program up to Elevation 799+6 as a minimum.

Both portions of the Radwaste Facility are designed and erected so that all liquid inventory will be contained within the structures in the event of pipe or tank ruptures caused by a seismic event or from other causes. Therefore, the reinforced concrete mats and a concrete wall of sufficient height to contain the entire liquid inventory are designed to withstand the effects of seismic loads as well as conventional loads. Loadings due to failure of the upper structure portions during the seismic event were not considered. Design, procurement and erection meet the requirements of the Duke Power Company Quality Assurance Condition 2 (QA2) program up to Elevation 799+6. A wall erected to Elevation 799+6 (bathtub) can contain the entire liquid inventory of the building.

For the east side of the facility, between column lines B and F, the framing is primarily of structural steel, and the structural design includes the effects of seismic and conventional loads. Design, procurement, and shop fabrication of the structural steel meet the requirements of the Duke Power Company QA 2 Program. Structural steel erection meets AISC requirements, but has no formal Quality Assurance requirements. The south-east portion of this area is reinforced concrete up to the floor at Elevation 819+0. The floor, supporting large tanks, is not designed to seismic requirements; the concrete columns are designed for seismic loadings except that the tie bars are reduced in size and number from the requirements for seismic forces, to permit ease in construction.

The west side of the facility, between column lines G and K, is a reinforced concrete structure, and the
9 analysis and design include the effects of seismic and conventional loads up to the bottom of the floor slab
9 at Elevation 819+0. Design, procurement and construction of these parts meet the requirements of the
Duke Power Company QA program. The floor slab at Elevation 819+0 and all reinforced concrete
9 elements above this floor, except for load bearing walls, are analyzed and designed for conventional loads
only, with good engineering practice applied to design, procurement and construction. The design of load
6 bearing walls above Elevation 819+0 includes seismic loads with no Quality Assurance requirements
applied to design, procurement or construction.

6 Independent loads are calculated on the following bases:

11.6.2.2.1 Wind Loadings

The design wind velocity is 95 mph at 30 ft. above the nominal ground elevation. According to ASCE Paper 3269, "Wind Forces on Structures," this represents the greatest wind velocity with a recurrence interval of 100 years. ANSI A58.1-1972, "Building Code Requirements for Minimum Design Loads in Building and Other Structures," recommends that buildings with a height-to-minimum horizontal dimension ratio exceeding five should be dynamically analyzed to determine the effect of gust factors.
6 However, since this structure has a height-to-width ratio less than five, a gust factor of unity is used in determining wind forces. Tornado and tornado missiles are not included as a design load.

11.6.2.2.2 Water Level Design

The yard grade is at elevation 796+0. All openings into the structure will be no lower than 797+0. A 2′-6″ minimum height curb is provided to contain any accidental spillage within the facility. The yard is provided with a surface water drainage system.

11.6.2.2.3 Dead Loads and Equipment Loads

6 A density of 150 lb/ft^3 is used for reinforced concrete dead weight computations. Structural steel weights
6 are based on their nominal weight per foot as given in the AISC "Manual of Steel Construction," eighth
6 edition. Weights of metal decking and siding are taken from supplier's catalogs. Weights of equipment,
6 tanks, etc., weighing more than 1000 lbs are taken from information supplied by the manufacturer. An
6 additional load of 150 lb/ft^2 is applied to floors, except for the drum storage area, and roofs in the reinforced concrete structure to account for suspended piping, electrical cable tray and small miscellaneous equipment weighing less than 1000 lbs. In the drum storage area, the additional load is 2250 lb/ft^2.

6 Additional loads of 50 lb/ft^2 on floors and 30 lb/ft^2 on roofs are applied in the structural steel portion, for
6 the same reason. Where cable tray is banked, the cable tray loading are calculated and applied as additional equipment load. A dead load of 20 lb/ft^2 is applied to areas covered by grating.

11.6.2.2.4 Live Loads

In the concrete portion, a live load of 125 lb/ft^2 is applied to floors and roof. In the structural steel portion, a live load of 150 lb/ft^2 is applied to floors and 20 lb/ft^2 is applied to roofs. A live load of 100 lb/ft^2 is applied to areas covered by grating.

11.6.2.2.5 Seismic Design

A nonlinear finite element soil-structure analysis (FLUSH) is used to generate seismic response at the ground surface due to bedrock motion. The rock motion input is a synthetic 5%g time history developed so that response spectra derived from that motion envelope the NRC Regulatory Guide 1.60 curves. The design response spectra are developed using procedures set forth in NRC Regulatory Guide 1.60, with maximum ground acceleration in both horizontal and vertical directions obtained from the soil-structure
6 interaction analysis. Response spectra analyses is performed for both horizontal directions. Vertical earthquake loads will be obtained by applying the maximum vertical acceleration to static loads.

11.6.2.3 Loads and Loading Combinations

9 The loads and combinations thereof used in the analysis and design of the Radwaste Facility are described below:

1. Normal Loads

   Normal loads are those loads to be encountered during normal facility operation.

   They include the following:

   D - Dead loads, including permanent equipment loads and hydrostatic loads.

   L - Live loads, including any movable equipment loads and other loads which vary with intensity and occurrence, such as soil pressure.

2. Severe Environmental Loads

   Severe environmental loads are those loads that could infrequently be encountered during the facility life.

   Included in this category are:

   E - Loads generated by the Operating Basis Earthquake

   W - Loads generated by the design wind specified for the facility.

11.6.2.3.1 Load Combinations for Concrete Structures

U designates the section strength required to resist design loads and is based on methods described in ACI 318-77. The following load combinations will be satisfied:

1. $U = 1.4D + 1.7L$
2. $U = .75\,(1.4D + 1.7L + 1.7W)$
3. $U = .75\,(1.4D + 1.7W)$
4. $U = .9D + 1.3W$
5. $U = .75\,(1.4D + 1.7L + 1.87E)$
6. $U = .75\,(1.4D + 1.87E)$
7. $U = .9D + 1.43E$

11.6.2.3.2 Load Combinations for Steel Structures

S designates the section strength required to resist design loads and is based on the elastic design methods and the allowable stresses defined in Part I, Sections 1.5.1, 1.5.2, 1.5.3, 1.5.4 and 1.5.5 of the AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," seventh edition.

Y designates the section strength required to resist design loads and is based on plastic design methods described in Part 2 of AISC "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," seventh edition.

The following load combinations will be used for the elastic working stress method:

1. $S = D + L$
2. $1.33S = D + L + E$
3. $1.33S = D + L + W$

In load combinations 2 and 3, S is increased by one-third in accordance with Section 1.5.6 in the AISC specification.

The following load combinations will be used for the plastic design method:

1. Y = 1.7D + 1.7L
2. Y = 1.3D + 1.3L + 1.3E
3. Y = 1.3D + 1.3L + 1.3W

Note: Loadings that include seismic factors will be used as a design basis to design the "bathtub."

11.6.3 MECHANICAL SYSTEMS

11.6.3.1 Liquid Waste and Recycle System

11.6.3.1.1 Design Bases

7 The Liquid Waste and Recycle System (LW) is designed to appropriately process all excess radioactive
water generated at the station. Decontaminated water will be reused by the station as make up or released
to the environment as appropriate. Generally, chemistry limits control recycle and radioactivity limits
control discharge. Contamination removed from processed water will be transferred to the Volume
7 Reduction and Solidification System for packaging and shipment to an approved processor or disposal
7 facility.

6 **Note:** The HPD Evaporator System is placed into a 'dry layup' condition until operating economics can
6 justify its use, and because of this water is not reclaimed for use/reuse by the station.

11.6.3.1.2 System Description

7 Four 10,000 gallon Feed Tanks are provided for batching reactor coolant and miscellaneous waste. These
7 tanks are managed as needed to receive waste from the plant.

Feed pumps, process filters, demineralizers, and demineralizer fines filters are provided in pairs, each
designed for ≤ 50 gpm. One 30 gpm evaporator is provided to be used either for concentration of boric
acid from reactor coolant or, if necessary, for use with a filter and demineralizer to provide the greatest
available decontamination for waste. An additional train of six demineralizers is available to process
liquid waste. Sufficient crossconnection is provided so that two independent streams can be processed
7 simultaneously. Possible lineups are: 1) a feed pump, filter, demineralizer, demineralizer fines filter,
7 evaporator processing reactor coolant and 2) a feed pump, filter, demineralizer, and demineralizer fines
7 filter processing miscellaneous floor drains. Other "normal" situations exist with total process rates from
7 5 to 100 gpm.

Six 10,000 gallon monitor tanks are provided for checking processed water quality and scheduling
7 transfers. Water may be released to the environment through a radiation monitor or be transferred to
7 Chemical Treatment Pond #3.

7 If dilution is required, processed water is released through a radiation monitor coordinated with a flow
7 meter. The monitor will terminate discharge if it detects activity in excess of the setpoint. The setpoint is
7 determined based on laboratory analyses. The setpoint guards against errors in the laboratory results.
7 Compensatory action is taken if the laboratory analysis can not be coordinated with the monitor's
7 setpoint (monitor out of service or activity below capability of the monitor to detect). Independent
7 samples are taken and analyzed instead of using the continuous monitor.

9 11.6.3.2 Powdered Resin Recovery System

11.6.3.2.1 Design Bases

The Powdered Resin Recovery System is designed to collect and sample each backwash from the
6 Condensate Polishing Demineralizer and to separate water from spent resin. In addition, the System can
6 use the spent resin to process liquid from the Laundry Hot Shower Tanks, and the Liquid Waste System.

11.6.3.2.2 System Description

6 Each backwash is sent to one of the two Backwash Receiving Tanks, BRT-A, or BRT-B. There the
6 resin is transferred to the Contaminated Backwash Receiving Tank (CBRT) where it can be used to
6 process additional waste water.

2 The resin in the backwash receiving tanks may also be used to process laundry and hot shower water and
2 to process/reprocess miscellaneous waste. This is accomplished by agitating the water and resin, then
2 proceeding with the decanting as described above.

6 Backwashes are allowed to settle. After sufficient settling has occurred, the excess water is decanted. The
7 decanted water is directed through the Resin Fines to the Decant Monitor Tank (DMT). Here the water
7 is sampled and directed to one of two locations; 1) Liquid Waste System, or 2) Chemical Treatment
6 Pond. The contaminated resin is transferred to the Facility Truck Bay and/or Drum Storage Facility for
6 dewatering in DOT approved shipping containers.

6 The dewatered containers are sampled, prepared and shipped to a NRC disposal facility or vendor-site for
6 further volume reduction.

11.6.3.3 Volume Reduction and Solidification System

11.6.3.3.1 Design Bases

The Volume Reduction and Solidification System (VR) is designed to prepare radioactive wastes for shipment and disposal, and to minimize the volume of waste shipped.

Note: The VR system (incinerator and dry product handling and drumming portions) has been placed in a layup condition until operating economics can justify its use.

11.6.3.3.2 System Description

In order to prepare wastes for shipment and minimize the volume of waste, wet wastes (e.g., contaminated oil, powdered resins) and dry trash are incinerated and the scrub liquor produced is completely dried. The results of both fluid bed processes are a dry, free-flowing mixture of salt granules and ash. This sand-like material is then packaged to meet Federal and State regulations. Resin which is too radioactive to incinerate will be solidified and/or packaged to meet Federal and State regulations.

The incinerator may be fed resin slurries, contaminated oil or shredded trash. Fluidizing air is electrically heated for startup and thereafter maintained by the combustion process. Liquid sprays (resin slurry or condensate) are provided to control temperature.

All normal operations of the Volume Reduction and Solidification System involving radioactive material are carried out remotely from the Radwaste Control Room. A remote control crane moves new drums from the clean fill stations to the waste drumming stations, stores or retrieves drums in the storage pit, and loads truck-mounted shielded casks used to ship solidified waste off site for disposal.

11.6.3.4 Instrument and Breathing Air Systems

2 These systems are described in Section 9.5.2, "Instrument and Breathing Air Systems."

2

11.6.3.5 Equipment Cooling System

11.6.3.5.1 Design Bases

The Equipment Cooling System is designed to remove heat from the components of the Liquid Waste Processing System and Radioactive Waste Solidification System. This system also supplies cooling water to the Radwaste Facility air compressors and HVAC coolers, and supplies service water for the facility.

11.6.3.5.2 System Description

The generating plants Condenser Circulating Water System serves as the suction source for the Equipment Cooling System. Two duplex basket-type strainers reduce particulate size to 1/16″ and two 100% capacity EC Supply Pumps rated at 2400 gpm, @ 160 ft. deliver flow to the secondary side of two plate-type heat exchangers. The primary side flow is circulated by two 100% capacity EC Circulating Pumps rated at 1600 GPM @ 85 ft. This flow provides cooling for the Liquid Waste Evaporator and the Volume Reduction System. An auxiliary supply is taken off the EC Supply Pump discharge for miscellaneous service water use.

11.6.3.6 Heating Ventilation and Air Conditioning

11.6.3.6.1 Design Bases

The Radwaste Facility HVAC consists of a Ventilation System and an Air Conditioning System. The principal objectives of the HVAC System are to supply sufficient filtered fresh air to maintain an aseptic condition, control the temperature for effective operation of process equipment, meet the "ALARA" related consideration with air flow by supplying air to clean areas and exhausting air from high radiation areas and to sample the exhaust air to monitor the release of airborne radioactive material from the building.

11.6.3.6.2 System Description

11.6.3.6.2.1 Ventilation System

The Ventilation System will supply filtered and tempered air to each area in sufficient quantity to reduce
8 the heat build up and keep the temperature below 110 degrees in the process areas. A positive exhaust system will be used to exhaust a quantity of air from each area which is sufficiently larger than the supply air to maintain a directed flow of air in the building. The exhaust air quality will be monitored. A filter train including rough, HEPA and charcoal filters will be used for the exhaust air from tank vents and fume hoods to minimize the emission of contamination from the building. There will be no recirculation of air to any process area.

11.6.3.6.2.2 Air Conditioning System

The Air Conditioning System will supply tempered and dehumidified air including fresh air to each area.
9 The areas to be air conditioned include, but are not limited too, the control room, the count room, the
9 Chem. & HP Lab, the Men and Women's Clean Change Areas, the Supervisor's office, and the clean and

9 contaminated maintenance shops. The Contaminated Maintenance shop and the personnel areas will be
air conditioned with 100% fresh air.

11.6.3.7 Drains

0 Roof drains and clean floor drains are piped to the station storm drain system.

0 Personnel area drains that are potentially contaminated are pumped to the facility sumps.

0 Sanitary drains are piped to the station sewage treatment plant.

0 Contaminated process and floor drains are piped to the facility sump.

11.6.4 REMOTE CONTROL SYSTEM

11.6.4.1 Design Bases

The Radwaste Remote Control System is designed to provide a means for operating the various mechanical and electrical systems in the Radwaste Facility from a centralized control area. This design will minimize the requirements for manning the facility, and will minimize the radiation exposure to the operator. While it is impractical to control all functions from a centralized location, remote control is employed in a practical manner where possible, particularly in situations involving radiation exposure to the operator.

11.6.4.2 System Description

6 The Radwaste Control Room (RCR) is located in the clean portion of the building where there are no
6 radiation shielding requirements. A cable spreading room is provided behind the RCR to allow for
control board and relay cabinet cable access.

6 Control boards designed by several different vendors as well as Duke-designed boards are located in the
6 RCR. The electrical project engineer coordinates between all parties to insure as much compatibility
between boards as is reasonably achievable. Human factors aspects of the control room and control
board designs including color coding, control board enhancement, process mimics, operator/control
6 interfaces, and RCR personnel traffic patterns are taken into consideration.

Since the RCR is the primary area of personnel activity for this facility, the Fire Detection System central
6 alarm station as well as any other "Facility protective" monitors are located there. Annunciators,
6 instrumentation, and control devices are installed as necessary to satisfy the intent of the Remote Control
System purpose.

11.6.5 FIRE DETECTION SYSTEM

11.6.5.1 Design Bases

The Radwaste Fire Detection System is designed to provide early warning at a central location in the event of a fire or conditions preceding the break out of a fire.

11.6.5.2 System Description

9 The Radwaste Fire Detection System central alarm station is located in the Radwaste control room.
6 Individual strings of various types of detectors emanate from the central alarm station to provide detection in selected areas of the facility. Detector locations and types (ionization, fixed temperature, rate-of-rise,
6 etc.) are determined by the fire protection engineer.

6 The detection system installed is of the two-wire type which will allow trouble alarm indication. This design approach should minimize personnel radiation exposure encountered in maintaining the system.
6 An alarm is provided in the Oconee plant (e.g., Unit 3 control room) to notify the plant operations personnel of a fire in the Radwaste Facility.

11.6.6 RADIATION MONITORING SYSTEM

11.6.6.1 Design Bases

The Radiation Monitoring System is designed to accurately monitor process, area and noble gas radiation within the facility. Particulate and iodine collection samplers are also installed in the exhaust system.

11.6.6.2 System Description

6 The Radiation Monitoring System consists of the components with their respective parameters as listed in Table 11-7.

11.6.7 RADIATION PROTECTION

11.6.7.1 Facility Design Features

The mechanical and electrical equipment is separated into clean, nonradioactive areas, curbed areas and shielded areas. Radioactive components are separated from each other to allow maintenance without
9 subsequent exposure from nearby components. Radioactive equipment with valves is provided in a valve gallery containing the valves and remote valve operators in an intermediate radiation area. Separation of system piping is also stressed to eliminate exposure in these galleries. Air regulators and other instrumentation associated with valve and system operation are located outside of the valve gallery, inside of the labyrinth entrance in a lower zone.

Feed tank exposure is minimized by using stainless steel lined rooms. Mixer motors for these tanks are located above the shielded tank room.

Process particulate filters are the backflushable type to eliminate exposure with filter replacement and are remotely operated.

Process resin demineralizers are used for ion removal.

8 All equipment suspected of crud accumulation is flushed prior to maintenance. Periodic piping review insures minimum piping crud traps.

The Volume Reduction System layout utilizes several individually shielded cubicles to separate components containing the majority of the radioactive material from the mechanical components such as the pumps and blowers which contain small amounts of radioactive material and which are expected to require periodic maintenance. In addition, the components containing the majority of the radioactive material are all fitted with decontamination nozzles so that the radioactive salts can be flushed from the system and the components readily decontaminated prior to required maintenance.

11.6.7.2 Shielding

11.6.7.2.1 Source Terms

9 Radiation source terms for the Radwaste Facility are separated into three systems; the Liquid Waste and
9 Recycle System (LW), the Resin Recovery System, and the Volume Reduction and Solidification System
9 (VR). The liquid waste source terms are derived by OSC-1696, "Radwaste Facility LW Source Terms."
9 The resin recovery source terms are derived by OSC-1823, "Oocnee Radwaste Facility Contaminated
9 Powdex Source Terms." The volume reduction and solidification source terms are derived by OSC-1824,
9 "Oconee Radwaste Facility VR System Source Terms." These calculations either reference ANSI
9 N237-1976/ANS-18.1, "Source Term Specification," or utilize computational code, N-237BURP,
9 C-6.11-8, November 1977, Rev. 1 for the determination of source strengths.

11.6.7.2.2 Radiation Zone Designations

The Radwaste Facility is divided into radiation zones based upon source term analyses, Regulatory Guide
9 8.8 and personnel radiation exposure limits; figures in the Environmental Qualification Criteria Manual
9 (EQCM) are marked to denote applicable radiation zones. These radiation zones are as follows:

Zone I: Designation for areas adjacent to the station site where Duke Power Company does not normally
2 exercise authority to control access. In accordance with applicable regulations (10CFR 20.1301(a)(1)), the
2 dose rate in these areas does not exceed 0.1 rem/yr.

2 Zone II: Areas within the station site where the station staff is expected to work continuously. For
conservatism, the limiting dose rate is selected as 0.5 mrem/hr. This is comparable to the criteria given in
2 10CFR 20.1302.

Zone III: Areas within the station where staff occupancy is expected to be periodic rather than
2 continuous. An employee could, however, remain in these areas and not exceed 5.0 mrem/hr.

Zone IV: Includes infrequently occupied work locations where the dose rate exceeds continuous
occupational levels but access need not be physically restricted. The limit dose rate for this zone is
3 designated as 50 mrem/hr. The precautions given in 10CFR 20.1601, 1602, and 1901 through 1905 for
Radiation Areas are employed where local dose rate levels in Zone IV warrant.

Zone V: Encompasses all areas of the station where the dose rate exceeds that of Zone IV. Access to
these areas is physically restricted, and Radiation Protection surveillance is required for occupancy, if any.
3 The precautions given in 10CFR 20.1601, 1602, and 1901 through 1905 for High Radiation Areas are
employed where local dose rate levels in Zone V warrant.

11.6.7.2.3 Shield Wall Thickness

The KAP VI computer code is used to determine the shield wall thickness for each component. KAP VI utilizes the point kernel technique to calculate radiation levels at detector points located within or outside a complex radiation source geometry.

11.6.8 REFERENCES

1. H. B. Tucker (Duke) letter to H. R. Denton (NRC) dated June 10, 1985.

2. J. F. Stolz (NRC) letter to H. B. Tucker (Duke) dated October 30, 1986.

9 11.7 CONVENTIONAL WASTEWATER TREATMENT SYSTEMS

9 11.7.1 DESIGN BASES

9 The Oconee Nuclear Station uses chemical processes to treat water for use in both the Reactor Systems
9 and Steam and Power Conversion Systems. Many of these chemical processes are governed by regulatory
9 criteria. For example, the National Pollutant Discharge Elimination System (NPDES) establishes criteria
9 for chemical concentrations released from the station. The bases for the Conventional Wastewater
9 Treatment Systems are to provide a means to treat wastewater prior to release so that it can meet
9 regulatory criteria.

9 11.7.2 SYSTEM DESCRIPTION

9 The Conventional Wastewater Treatment System as seen in Figure 11-4 consists of three treatment
9 ponds: CTP#1, CTP#2, and CTP#3. CTP#1 and CTP#2 are parallel ponds with either in service while
9 the other is providing treatment or discharging. Pumps are provided for recirculation or controlled
9 discharge to CTP#3. The Conventional Wastewater Treatment System receives input from various drains
9 and sumps throughout the plant.

THIS IS THE LAST PAGE OF THE CHAPTER 11 TEXT PORTION.

APPENDIX 11. CHAPTER 11 TABLES AND FIGURES

7 **Table 11-1. Potential Radioactive Waste Quantities from Three Units**

Waste Source	*Quantity/Year ($ft.^3$)	Assumptions & Comments
Reactor Coolant System		
Startup Expansion	39,800	Four cold startups per unit
Startup Dilution	49,000	One startup from cold condition at beginning of cycle, 77.5, 155 and 232.5 full power days, respectively, per unit
Lifetime Shim Bleed	43,800	Dilution 1070 to 180 ppm boron in each unit
System Drain	18,300	Drain of each unit to level of outlet nozzles during refueling
Liquid Waste		
Primary System	161,019	3300 gal/day Rate of Input
Spent Fuel Pool	26,349	540 gal/day Rate of Input
Cask Decontamination	17,566	360 gal/day Rate of Input
Component Coolant	17,566	360 gal/day Rate of Input
Service Water	58,553	1200 gal/day Rate of Input
Decontamination Room	87,828	1800 gal/day Rate of Input
Resin Sluice	23,421	480 gal/day Rate of Input
Miscellaneous System Leakage	351,312	·5 gal/min Rate of Input
OTSG Tube Leaks	40,140	1 Tube Leak/Unit/yr = > 1 Vol Drain + 3 Flush Vols of Secondary Side
LHST	161,019	3300 gal/day Rate of Input
Gaseous Waste		
Waste Gas	131,400	
Solid Waste		
Spent Bead Resins	2,000	
Spent Powdex Resin	5,000	

Note:

* Quantities based on data gathered at ONS for years 1977 and 1978, and values found in "Evaluation of
7 compliance with 10CFR50 Appendix I," June 4, 1976. Actual amounts vary from year to year depending on
7 unit operating history. The actual liquid waste generated is reported in the Oconee Annual Effluent Report.
9 The actual gaseous waste activity that is released is reported in the Oconee Annual Effluent Release Report.

Table 11-6 (Page 1 of 7). Waste Disposal System Component Data (Component Quantities for Three Units)

Low Activity Waste Tank	
Quantity	2
Volume each, cu. ft.	398
Material	Concrete with Stainless Steel Liner
High Activity Waste Tank	
Quantity	2
Volume each, cu. ft.	262
Material	Concrete with Stainless Steel Liner
Misc. Waste Holdup Tank	
Quantity	2
Volume each, cu. ft.	2,700 for Units 1 and 2 shared 1,550 for Unit 3
Material	Carbon Steel with Stainless Clad
Design Pressure	Vessel Full Plus 10 ft. Hydro Head
Spent Resin Storage Tank	
Quantity	2
Volume each, cu. ft.	450 for Units 1 and 2 shared 380 for Unit 3
Material	Stainless Steel
High Activity Spent Resin Storage Tank	
Quantity	1 for Unit 3
Volume, cu. ft.	380
Material	Stainless Steel
Reactor Building Normal Sump	
Quantity	3
Volume each, cu. ft.	45
Material	Concrete
Reactor Building Emergency Sump	
Quantity	3
Volume each, cu. ft.	540
Material	Concrete
9 GWD Tank	
Quantity	4
8 Volume each, cu. ft.	1,098

Table 11-6 (Page 2 of 7). Waste Disposal System Component Data (Component Quantities for Three Units)

	Material	Carbon Steel
	Design Pressure, psig	100
6	Misc. Waste Evaporator Feed Tank*	
	Quantity	1
	Volume, cu. ft.	400
	Material	Stainless Steel
	Design Pressure	Vessel Full Plus 10 ft. Hydro Head
6	Waste Evaporator*	
	Quantity	1
	Process Rates, lb/hr	5,060
	Material	Stainless Steel
	Design Pressure, psig	15
	Low Activity Waste Tank Pump	
	Quantity	4
9	Capacity each, gal/min	100
9	Diff. Head, ft.	200
9	High Activity Waste Tank Transfer Pump	
	Quantity	4
	Capacity each, gal/min	50
9	Diff. Head, ft.	200
9	Misc. Waste Transfer Pump	
	Quantity	4
	Capacity each, gal/min	50
9	Diff. Head, ft.	200
	Spent Resin Sluicing Pump	
	Quantity	2
	Capacity each, gal/min	50
	Diff. Head, ft.	50
	Spent Resin Transfer Pump	
	Quantity	2
	Capacity each, gal/min	10
	Diff. Head, ft.	100

6 *Component is in a layup condition.

Table 11-6 (Page 3 of 7). Waste Disposal System Component Data (Component Quantities for Three Units)

	Reactor Building Normal Sump Pump	
	Quantity	6
	Capacity each, gal/min	25
	Diff. Head, ft.	28
6	Waste Evaporator Feed Pump*	
	Quantity	1
	Capacity, gal/min	7-1/2
	Diff. Head, ft.	60
6	Waste Evaporator Recirculating Pump*	
	Quantity	1
	Capacity, gal/min	160
	Diff. Head, ft.	53
6	Waste Evaporator Distillate Pump*	
	Quantity	1
	Capacity, gal/min	9-1/2
	Diff. Head, ft.	62
8	See Note (a)	
9	GWD Filter	
	Quantity	2
	Rating, scfm	200
	Type	Prefilter, Absolute and Charcoal
	Material	11 Gauge Galvanized Steel
9	GWD Exhauster	
	Quantity	2
9	Rating, scfm	200 at 6 in. Water Gauge External
9		Static Pressure
	Type	Backward Curved - Centrifugal
9	GWD Compressor	
	Quantity	4
	Capacity each, cfm	48 at 85 psig
	Type	Centrifugal Displacement

6 *Component is in a layup condition.

8 **Note:**

8 (a) Waste Evaporator Distillate Pump data included for historical purposes only.

Table 11-6 (Page 4 of 7). Waste Disposal System Component Data (Component Quantities for Three Units)

9 Interim Evaporator Feed Tanks*

Quantity	2
Volume, gal	17,000
Design Pressure	Static head plus 5 psig
Design Temperature, °F	200
Material	304 stainless steel

9 Interim Evaporator Condensate Monitor Tanks*

Quantity	2
Volume, gal	9,000
Design Pressure	Static head plus 5 psig
Design Temperature, °F	200
Material	304 stainless steel

9 Interim Evaporator Concentrates Storage Tank*

Quantity	1
Volume, gal	3,000
Design Pressure	Static head plus 5 psig
Design Temperature, °F	200
Material	304 stainless steel

9 Interim Evaporator Condensate Return Tank*

Quantity	1
Receiver volume, gal	100
Design Pressure	Atmospheric
Design Temperature, °F	212
No. of Pumps	2
Design Flow, gal/min	25
Design Head, ft	65

9 Interim Evaporator Feed Filter*

	Quantity	1
	Type	Cage Assembly (disposable synthetic cartridged)
	Design Pressure, psig	200
	Design Temperature, °F	250
	Design Flow Rate, gal/min	35
	Pressure Drop at Design Flow, psi	Clean - 5
9		Fouled - 20
9	Retention of 25 Microns particles	98%
9	Material	Stainless Steel

6 *Component is in a layup condition.

Table 11-6 (Page 5 of 7). Waste Disposal System Component Data (Component Quantities for Three Units)

9	Interim Evaporator Condensate Filter*	
	Quantity	1
	Type	Cage Assembly (disposable synthetic cartridge)
	Design Pressure, psig	300
	Design Temperature, °F	250
	Design Flow Rate, gal/min	150
	Pressure Drop at Design Flow, psi	Clean - 5
9		Fouled - 20
9	Retention of 25 Micron Particles	98%
9	Material	Stainless Steel
9	Interim Evaporator Condensate Demineralizer*	
	Quantity	1
	Type	Non-regenerable
	Design Temperature, °F	200
	Design Pressure, psig	150
	Vessel Volume, ft^3	55
	Resin Volume, ft^3	50
	Design Flow, gal/min	310
	Material	Stainless Steel
	Resin Type	Mixed bed
9	Interim Evaporator Feed Pump*	
	Quantity	1
	Type	Canned centrifugal
	Design Flow, gal/min	35
	Design Head, ft	250
	Design Pressure, psig	150
	Design Temperature, °F	200
	Operating Temperature, °F	120
	Material	Stainless Steel
9	Interim Condensate Monitor Tank Pumps*	
	Quantity	2
	Type	Canned centrifugal
	Design Flow, gal/min	100
	Design Head, ft	250
	Design Pressure, psig	150
	Design Temperature, °F	200
	Operating Temperature, °F	120
	Material	Stainless Steel

6 *Component is in a layup condition.

Table 11-6 (Page 6 of 7). Waste Disposal System Component Data (Component Quantities for Three Units)

6 Interim Evaporator Concentrates Transfer Pump*

Quantity	1
Type	Canned centrifugal
Design Flow, gal/min	35
Design Head, ft	250
Design Pressure, psig	150
Design Temperature, °F	200
Operating Temperature, °F	170
Material	Stainless Steel

9 Low Activity Equipment Drains Sump Pumps

Quantity	2
Type	Vertical
Design Flow, gal/min	50
Design Head, ft	100
Material	Stainless Steel

High Activity Equipment Drains Sump Pumps

Quantity	2
Type	Vertical
Design Flow, gal/min	50
Design Head, ft	100
Material	Stainless Steel

9 Interim Evaporator Distillate Pump*

Quantity	1
Type	Canned Centrifugal
Design Flow, gal/min	15.6
Design Head, ft	208
Design Pressure, psig	150
Design Temperature, °F	220
Operating Temperature, °F	80-110
Material	Stainless Steel

6 *Component is in a layup condition.

Table 11-6 (Page 7 of 7). Waste Disposal System Component Data (Component Quantities for Three Units)

9 Interim Waste Evaporator Package (Westinghouse)

Quantity	1
Nominal Capacity, gal/min	15
Steam Supply Pressure, psig	50
Steam Flow, lb/hr	10,500
Cooling Water Flow, gal/min	780
Concentrates Batch Volume, gal	500
Max. Boron Concentration, ppm	21,000
9 Liquid DF[1]	10^6
9 Gaseous DF[2]	10^5

9 Interim GWD Tanks

Quantity	3
8 Volume, ft^3	1070
Design Pressure, psig	100
Design Temperature, °F	Material
200	Carbon steel

9

Note:

9 1 DF for liquid $= \frac{\text{activity in concentrates}}{\text{activity in distillate}}$

9 2 DF for gas $= \frac{\text{activity in feed}}{\text{activity in distillate}}$

6 *Component is in a layup condition.

2 **Table 11-7 (Page 1 of 5). Process Radiation Monitors**

	Channel Number and Function	Type Detector	Sensitivity (Background Equivalent Concentration and Count Rate)	Range
4 4 4	RIA-31 Monitors LPSW (Multipoint)	NaI 1-½″D x 1″L 4″ Pb shield	10 mR/hr = 2.5 x 10^{-6} μCi/ml 2.5 mR/hr = 1.6 x 10^{-7} μCi/ml	(10-10^{7} cpm)
2 9 1	RIA-32 3RIA-32 Aux. Bldg. Gas Monitor	Plastic beta Scint. 2.125″D x .01″T 3″ Pb shield	2.5 mR/hr = 3.6 x 10^{-7} μCi/ml Xe-133 = 10 cpm	(10-10^{7} cpm)
9 9	RIA-33 Waste Disposal (Normal)	NaI 1½″D x 1″L 4″ Pb Shield	2.5 mR/hr = 6.2 x 10^{-8} μCi/ml	(10-10^{7} cpm)
9 4 4 4	1RIA-35 2RIA-35 3RIA-35 Total LPSW Discharge Header from Aux. Bldg.	NaI 1-½″D x 1″L 5″ Pb Shield	1 mR/hr = 4.3 x 10^{-6} μCi/ml 2.5 mR/hr = 6.2 x 10^{-8} μCi/ml	(10-10^{7} cpm)
2 2 2 2	RIA-37 3RIA-37 Waste Disposal Gas (Normal)	Plastic beta scint. 2″D x 0.007″T 4″ Pb shield	2.5 mR/hr = 1.34 x 10^{-2} μCi/ml Xe-133 = 10 cpm	(10-10^{7} cpm)
2 2 2 2	RIA-38 3RIA-38 Waste Disposal Gas (High)	G.M. 4″ Pb shield	2.5 mR/hr = 1.34 x 10^{-2} μCi/ml Xe-133 = 10 cpm	(10-10^{6} cpm)
2 9 2	RIA-39 3RIA-39 Control Room Gas	Plastic beta scint. 2.125″D x .01″T 3″ Pb shield	2.5 mR/hr = 3.6E-7 μCi/ml Xe-133 eq = 10 cpm	(10-10^{7} cpm)

2 **Table 11-7 (Page 2 of 5). Process Radiation Monitors**

	Channel Number and Function	Type Detector	Sensitivity (Background Equivalent Concentration and Count Rate)	Range
2 9 1	1RIA-40 2RIA-40 3RIA-40 Condenser Air Ejector off gas	Plastic beta scint. 2.125″D x .01″T 3″ Pb shield	2.5mR/hr = 3.6E-7 μCi/ml Xe-133 eq = 10 cpm	(10-10^7 cpm)
2 9 9	RIA-41 3RIA-41 Spent Fuel Bldg. Gas	Plastic beta scint. 2.125″D x .01″T 3″ Pb shield	2.5 mR/hr = 3.6E-7 μCi/ml Xe-133 eq = 10 cpm	(10-10^7 cpm)
3 3 3	RIA-42 3RIA-42 Recirculating Cooling Water	NaI 1-½″D x 1″L 4″ Pb lead	2.5 mR/hr = 1.6 x10^7μCi/ml	(10-10^7 cpm)
8 1 1	1RIA-43 2RIA-43 3RIA-43 Unit Vent Particulates	Plastic beta scint. 1-⅛″ x ⅝″ x .01″T 2.5″ Pb shield	2.5 mR/hr = 1.1 x 10^{-11} μCi/ml (2 SCFM Flow)	(10-10^7 cpm)
8 1 1 1	1RIA-44 2RIA-44 3RIA-44 Unit Vent Iodine	NaI 2″D x 2″L 3″ Pb shield	2.5 mR/hr = 4.7 x 10^{-11} μCi/ml (2 SCFM Flow)	(10-1E7 cpm)
8 1 1	1RIA-45 2RIA-45 3RIA-45 Unit Vent Gas (Normal)	Plastic beta scint. 2″D x .01″T 3″ Pb shield	2.5 mR/hr = 5.5 x 10^{-7} μCi/ml Xe-133 = 8 cpm	(10-1E7 cpm)
9 9	4RIA-45 Radwaste Facility Vent (Normal)	Plastic beta scint. 2″D x .01″T 5″ Pb shield	5 mR/hr = 5.5 x 10^{-7} μCi/ml	≃2E-7 to 2E-1 μCi/ml Xe-133 (readout in μCi/ml)

2 **Table 11-7 (Page 3 of 5). Process Radiation Monitors**

	Channel Number and Function	Type Detector	Sensitivity (Background Equivalent Concentration and Count Rate)	Range
8 1 1	1RIA-46 2RIA-46 3RIA-46 Unit Vent Gas (High)	Cadmium Telluride (CdTe) 2mm x 5mm x 2mm T 2″ Pb shield	3.5 mR/hr = 1.1E-3 μCi/ml Xe-133 = 4 cpm	(10-1E7 cpm)
9 9	4RIA-46 Radwaste Facility Vent (High)	G.M. 5″ Pb shield	5 mR/hr = 1 x 10^{-3} μCi/ml	1E-3 to 2E2 μCi/ml (readout in μCi/ml)
8 1 1	1RIA-47 2RIA-47 3RIA-47 Reactor Building Particulate	Plastic beta scint. 1⅛″ x ⅝″ x .01″T 2.5″ Pb shield	2.5 mR/hr = 7.0 x 10^{-12} μCi/ml (3 SCFM Flow)	(10-1E7 cpm)
8 1 1	1RIA-48 2RIA-48 3RIA-48 Reactor Building Iodine	NaI 2″D x 2″L 3″ Pb shield	2.5 mR/hr = 3.1 x 10^{-11} μCi/ml (3 SCFM Flow)	(10-1E7 cpm)
8 1 1	1RIA-49 2RIA-49 3RIA-49 Reactor Building Gas	Plastic Beta Scint. 2″D x .01″T 3″ Pb shield	2.5 mR/hr = 5.5 x 10^{-7} μCi/ml Xe-133 = 8 cpm	(10-1E7 cpm)
8 1 1	1RIA-49A 2RIA-49A 3RIA-49A Reactor Building Gas (High)	Cadmium Telluride (CdTe) 2mm x 5mm x 2mm T 2″ Pb shield	3.5 mR/hr = 1.1E-3 μCi/ml Xe-133 = 4 cpm	(10-1E7 cpm)
3 3 3	1RIA-50 2RIA-50 3RIA-50 Component Cooling Water	NaI 1-½″D x 1″L 4″ Pb shield	2.5 mR/hr = 1.6 x 10^{-7} μCi/ml	(10-10^{7} cpm)

2 **Table 11-7 (Page 4 of 5). Process Radiation Monitors**

	Channel Number and Function	Type Detector	Sensitivity (Background Equivalent Concentration and Count Rate)	Range
2 3				
7 9 9 7	RIA-53 Interim Radwaste Bldg. Vent Gas	Plastic Beta Scint. 2″D x 0.01″T 3″ Pb shield	2.5 mR/hr = 3.6 x 10^{-7} μCi/ml Xe-133 = 10 cpm	(10-10^7 cpm)
9 9	RIA-54 Turbine Bldg. Sump	NaI Scint. 1-1½″D x 1″L 4″ Pb shield	2.5 mR/hr = 1.6 x 10^{-7} μCi/ml	10-10^7 cpm
9 2 9	3RIA-54 Turbine Bldg. Sump	NaI Scint. 1½″D x 1″L 4″ Pb shield	2.5 mR/hr = 1.6 x 10^{-7} μCi/ml	10-10^7 cpm
3				
9 9 9	1RIA-16 1RIA-17 2RIA-16 2RIA-17 3RIA-16 3RIA-17 Steam Header Gross Activity	G. M. Detector (Low Range)/ 3.2″D x 6.6″L Ion Chamber (High Range) 2.5″D x 9.2″L 3″ Pb shield	500 cpm/mR/hr 1.2 E-10 Amp/R/hr	0.01-10^3 mR/hr 10^2-10^7 mR/hr
3 9	1RIA-56 2RIA-56 3RIA-56 Unit Vent Gas(High High)	Ion Chamber unshielded	1 x 10^{-11} amps/R/hr	1-10^8 R/hr 1-10^8 R/hr

2 **Table 11-7 (Page 5 of 5). Process Radiation Monitors**

	Channel Number and Function	Type Detector	Sensitivity (Background Equivalent Concentration and Count Rate)	Range
8	1RIA-57	Coaxial Ion Chamber	1 x 10^{-11} amps/R/hr	1-10^{8} R/hr*
9	2RIA-57	unshielded		
	3RIA-57			
	1RIA-58			
	2RIA-58			
	3RIA-58			
2	Reactor Building			
2	Gas(High High)			
2				

8 * RIAs 57/58 are on-scale at approximately 1R/hr.

9 **Figure 11-5.**
9 **Deleted Per 1999 Update**

7 **Figure 11-6.**
7 **Deleted Per 1997 Update**

TABLE OF CONTENTS

LIST OF TABLES

CHAPTER 12. RADIATION PROTECTION

0 12.1 ENSURING THAT OCCUPATIONAL RADIATION EXPOSURES
0 ARE AS LOW AS IS
0 Reasonably Achievable (ALARA)

12.1.1 POLICY CONSIDERATIONS

0 Duke Power Company management is firmly committed to the "As Low As Is Reasonably Achievable" (ALARA) philosophy for all nuclear operations. This commitment is stated in the DPC ALARA Manual. A formal ALARA program has been established in order to convey and enforce Duke management's commitment to ALARA. This program was established in conformance with the
9 requirements of Regulatory Guide 8.8, 8.10 and 10CFR20 to ensure that occupational exposures are
7 maintained ALARA. It consists of the following:

9 1. a published DPC ALARA Manual;

2. continued surveillance and evaluation of in-plant radiation and contamination conditions, as well as the monitoring and control of the exposure of personnel, by the station and General Office Radiation
7 Protection staff; and

7 3. an ALARA Committee consisting of site management and representatives from applicable groups,
7 whose purpose is to refine the site ALARA program.

The committee members have extensive background in nuclear plant radiation and exposure control, including such areas as layout, shielding, personnel access, ventilation, waste management, monitoring systems, operations, and maintenance.

Although upper level management is vested with the primary responsibility and authority for administering the Duke ALARA program, the responsibility for ALARA is extended through lower management to the individual employee. The specific responsibilities of the General Office and Station Radiation Protection staffs are to ensure that:

1. An effective ALARA program is established at each Duke nuclear station that appropriately integrates
7 Duke management philosophy and NRC regulatory requirements and guidance;

0 2. A periodic written review of the on-site radiation control program is performed to assure that
7 objectives of the ALARA program are attained;

9 3. Pertinent information concerning radiation exposure of personnel from other utilities and research
9 work are reflected in the design and operation of Duke stations;

9 4. Appropriate radiological experience gained during the operation of nuclear power stations is factored into revisions of procedures to assure that the procedures continually meet the objectives of the
7 ALARA program;

5. Necessary assistance is provided to ensure that operations, maintenance, and decommissioning
7 activities are planned and accomplished in accordance with ALARA objectives; and

6. Trends in station personnel and job exposures are analyzed in order to permit corrective actions to be taken with respect to adverse trends.

Reports of the findings of the General Office and Station Radiation Protection staffs are also effectively conveyed to management.

7 Specific responsibilities of station personnel are to ensure:

7 1. Activities are planned and accomplished in accordance with the objectives of the ALARA program;

2. Procedures and their revisions are implemented in accordance with the objectives of the ALARA
7 program; and

7 3. The General Office Radiation Protection staff and the Site Engineering staff are consulted as necessary for assistance in meeting ALARA program objectives.

7 Other group and individual responsibilities to the ALARA program are outlined in Section III of the DPC ALARA Manual.

12.1.2 DESIGN CONSIDERATIONS

ALARA is a major design consideration which is carried out in accordance with section C.1 of Regulatory Guide 8.8. Consideration was given to such factors as projected component dose rates, space, mobility, accessibility, etc., during the initial design and construction phases of Oconee Nuclear Station. There is a large degree of component separation between high and low radiation levels. Several
7 components are provided with flushing capability where the potential of exposure from CRUD exists.
2 Engineering evaluations supplement a formal operational feedback program which is used to identify specific and/or generic problems and implement design improvements.

ALARA exposures receive further attention through the training of designers and in equipment selection.
7 Section IX of the System ALARA Manual provides guidance to ensure that personnel who initiate and
7 plan modifications are cognizant of dose reduction considerations by formal training.

7 This guidance provides designers with a working knowledge of radiation protection. Remedial or refresher
7 training is also provided based upon experience and regulatory guidance, including any new technology or
7 refinements.

12.1.3 ALARA OPERATIONAL CONSIDERATIONS

Consistent with Duke Power Company's overall commitment to keep occupational radiation exposures as
0 low as is reasonably achievable (ALARA), specific plans and procedures are followed by station personnel to assure that ALARA goals are achieved. Operational ALARA policy statements are formulated at the
9 corporate staff level in the Nuclear Generation Department through the issuance of the Radiation
9 Protection Policy Manual, ALARA Manual and procedures. These statements and procedures are
9 consistent with the intent of Section C.1 of Regulatory Guides 8.8, 8.10 and 10CFR20.

7 Personnel and job exposure trends are reviewed by site management and the general office, and appropriate action is taken. Summary reports of occupational exposure are provided that describe
7 problem areas and jobs where high radiation doses are encountered. The reports identify which work group is accumulating the highest doses. Recommendations are then made for changes in operating, maintenance, and inspection procedures or for modifications to the station as appropriate to reduce doses.

Maintenance activities that could involve significant radiation exposure of personnel are carefully planned. They utilize any previous operating experience and are carried out using well trained personnel and proper equipment. Radiation Work Permits (RWP's) for non-routine operations, or Standing Radiation Work
9 Permits (SRWP's) for routine operations are issued for each radiological job. (S)RWP's lists Radiation Protection requirements that shall be followed by all personnel working in the Radiation Control Area
2 (RCA)/Radiation Control Zone (RCZ). Where applicable, specific radiation exposure reduction techniques, such as those set out in Regulatory Guide 8.8, are evaluated and used. Applicable procedures

7 for maintenance, inservice inspection, radwaste handling, and refueling, are well planned and developed by
7 cognizant groups. These procedures are reviewed by the station radiation protection staff to ensure that exposures will be ALARA.

Careful personnel radiation and contamination monitoring are integral parts of such maintenance activities. During and upon completion of major maintenance jobs, personnel radiation exposures are
7 evaluated and assessed relative to estimated exposures. From this appropriate changes can be made in techniques or procedures as soon as practicable for future jobs. The General Office Radiation Protection staff also conducts reviews of radiation exposure related activities to assure that procedures are adequate,
7 that they are being followed properly, and that deficiencies are corrected as soon as practicable.

The station ALARA Committee carefully reviews operations and maintenance activities involving the major plant systems to further assure that occupational exposures are kept ALARA.

7

12.2 RADIATION SOURCES

System activity levels are based on the Reactor Coolant System design activity levels defined in Table 11-5. Operation of each unit at rated power is assumed. Other parameters employed in shielding analysis are listed in Table 12-1.

12.3 RADIATION PROTECTION DESIGN FEATURES

12.3.1 FACILITY DESIGN FEATURES

The shielding is designed to perform two primary functions: (1) to ensure that, during normal operation, the radiation dose to operating personnel and to the general public is within the limits set forth in 10CFR 20 and is ALARA; and (2) to ensure that operating personnel are adequately protected in the event of a reactor accident so that the accident can be terminated without undue hazard to the general public.

Each area in the station is classified according to the dose rate allowable in the area, based on the expected frequency and duration of occupancy. These radiation zones are summarized below.

Location	Dose Rate, mrem/hr
Exclusion area boundary	0.05
2 Offices in Controlled Area (00B, Admin Bldg)	0.25
Offices, control room Turbine Building	0.5*
Normally accessible areas in Auxiliary Building	2.0
Above fuel storage pool with normal complement of fuel assemblies	2.5-10
Above reactor vessel and over fuel storage pool when handling fuel assemblies	10-20
Normally accessible areas in Reactor Building during full power operation	25
Inside control room following maximum hypothetical accident	3 rem whole body total dose: integrated over first 90 days after accident, assuming 8 hours per day per shift

* Certain areas of the turbine buildings are controlled and have higher dose rates resulting from primary to secondary leakage.

Piping and equipment components are shielded by concrete walls and floors of varying thickness, depending on the magnitude of the sources in each pipe section and component, and on the access requirements in a particular area. In some areas local shielding in the form of removable lead or concrete blocks are utilized to facilitate maintenance or repair operations.

12.3.2 SHIELDING

The material used for the primary, secondary, and Reactor Building shields is ordinary concrete with a density of approximately 140 lbs./ft^3. Since the primary and secondary shielding walls serve as the refueling structure, give support for the reactor coolant components under pipe rupture conditions, and provide missile shielding, they are reinforced and designed to be self-supporting. Descriptions of areas requiring shielding are presented below.

12.3.2.1 Reactor Building Shielding

12.3.2.1.1 Primary Shield

The primary shield consists of reinforced concrete which surrounds the reactor vessel and extends upward from the Reactor Building floor to form the walls of the fuel transfer canal. The shield thickness is 5 ft. up to the height of the reactor vessel flange, where the thickness is reduced to 4.5 ft. The primary shield is designed to meet the following objectives:

1. To attenuate the neutron flux in order to limit the activation of component and structural materials.
2. To limit the radiation level after shutdown so that access to the Reactor Coolant System equipment is permissible.
3. To reduce, in conjunction with the secondary shield, the radiation level from sources within the reactor vessel to allow limited access to the Reactor Building during normal full power operation.

12.3.2.1.2 Secondary Shield

The secondary shield is a 4 ft. thick reinforced concrete structure which surrounds the reactor coolant equipment, including the piping, pumps, and steam generators. The shielding is designed to reduce radiation levels from activity in the reactor coolant and to supplement the primary shield in the attenuation of neutrons and secondary gamma rays to permit limited access to the Reactor Building during full power operation.

12.3.2.1.3 Reactor Building Shield

The Reactor Building shield is a reinforced, prestressed concrete structure with 3.75 ft. thick cylindrical walls and a 3.25 ft. thick dome. In conjunction with the primary and secondary shields, it limits the radiation level outside the Reactor Building from all sources inside the Reactor Building to no more than 0.5 mrem/hr. at full power operation. The shielding is also designed to protect station personnel from radiation sources inside the Reactor Building following the Maximum Hypothetical Accident (gross release of fission products).

Other significant shielding inside the Reactor Building is listed in Table 12-2.

12.3.2.2 Auxiliary Building Shielding

The major radiation sources are piping and equipment components handling potentially contaminated fluid, practically all of which are located on the 758′-0″, 771′-0″, and 783′-9″ levels. Groups of equipment or individual equipment items are separated by shielding walls such that systems and equipment can be isolated for maintenance with no significant radiation interference from other systems or equipment. During normal operation, there is no need to occupy these potentially radioactive equipment areas. Potential radiation sources and associated shielding are listed in Table 12-2. Additional shielding is also provided around the control room to ensure that exposure to operating personnel in the control room is within the design limits following a Design Basis Accident (DBA).

12.3.2.3 Post LOCA Shielding Review

A post LOCA Shielding review of the Oconee Nuclear Station was conducted pursuant to the requirements of NUREG-0578. Shielding review identified a potential for exceeding personnel exposures in GDC-19 for the control room due to its proximity to the mechanical penetration room. The low pressure recirculation piping routed through the mechanical penetration room could potentially contain highly radioactive water post LOCA. Permanently installed lead shielding was provided along the control room walls adjacent to the mechanical penetration rooms to ensure that the personnel exposures in the control rooms do not exceed the limits specified in GDC-19 (NSM-1393) for all units. Caustic addition valves were relocated and provided with remote operators to assure operability and access. The Shielding review verified that the required personnel access to all vital areas was feasible without exceeding the radiation exposure limits following a LOCA accident.

12.3.3 AREA RADIATION MONITORING SYSTEM

12.3.3.1 Design Bases

0 The Area Radiation Monitoring System, consists of coaxial ion chambers, G-M detectors, and beta scintillation detectors. It is designed to indicate existing radiation levels and to alarm when levels exceed setpoints in various remote locations throughout the station where personnel are most likely to be exposed. Indications from the monitors are used in conjunction with station operating procedures to assure that radiation exposure of personnel does not exceed 10CFR 20 limits.

12.3.3.2 Description

Numbers and locations of the Area Radiation Monitors are shown in Table 12-3.

2 Control room indication is provided for each monitor indicating R/hr, mrad/hr, or cpm. Indication for
2 Oconee 1 and 2 monitors are located in Oconee 1 and 2 control room. Indication modules for Oconee 3
monitors are located in Oconee 3 control room.

1 Each detector assembly (except for the high range area detectors, and the beta scintillation detector
assemblies) is equipped with a check source that is automatically actuated on a periodic basis. The failure
0 of any applicable channel to respond to the source will initiate an alarm in the control room. Radiation
levels exceeding the alarm setpoint for any detector will cause an alarm at that detector location and in the
control room.

12.3.3.3 Evaluation

The Area Radiation Monitoring System detectors are located throughout the station in locations where
significant radiation levels may exist, and change with time and the operation being performed. They are
designed primarily for the protection of personnel performing such operations as routine coolant sampling,
refueling, Reactor Building entry, radioactive waste disposal operations, and for certain other operating
and maintenance work. The system has sufficient range and flexibility to permit readout during routine
operations and during any transient or emergency conditions that may exist. The equipment is
4 self-checking for proper operation, and alarms both in the local area and in the respective control room.
1 Where necessary or desirable, readout is also provided locally in certain locations.

Several channels of the Area Radiation Monitoring System will be utilized for primary indication and
4 backup in evaluating the extent of fission product release involved in both the LOCA and DBA.

12.4 RADIATION PROTECTION PROGRAM

The administrative organization of the Radiation Protection program and the qualifications of the personnel responsible for the program and for handling and surveying radioactive material are discussed in Section 13.1, "Organizational Structure." The administrative organization is responsible for and has appropriate authority for assuring that the three basic objectives of the Radiation Protection program at Oconee Nuclear Station are achieved. These objectives are to:

1. Protect personnel
2. Protect the public
3. Protect the station

<u>Protection of Personnel</u>, includes surveillance and control over internal and external radiation exposure and maintaining the exposure of all personnel within permissible limits and as low as is reasonably achievable (ALARA).

<u>Protection of the public</u>, includes surveillance and control over all station conditions and operations that may affect the health and safety of the public. Included are such activities as radioactive gas, liquid and solid waste disposal, shipment of radioactive materials, an environmental radioactivity monitoring plan and maintaining portions of the station emergency plan.

<u>Protection of the station</u>, includes the continuous determination and evaluation of the radiological status of the station for operational safety and radiation exposure control purposes. This work is performed in order to warn of possible detrimental changes and exposure hazards, to determine changes or improvement needed, and to note trends for planning future maintenance work.

This administrative organization is also responsible for and has appropriate authority for maintaining occupational exposures as far below the specified limits as reasonably achievable by assuring that:

1. Station personnel are made aware of management's commitment to keep occupational exposures as low as is reasonably achievable;
2. Formal reviews are performed periodically to determine how exposures might be lowered;
3. There is a well-supervised radiation protection capability with specific defined responsibilities;
4. Station workers receive sufficient training;
5. Sufficient authority to enforce safe station operation is provided;
6. Modification to operating and maintenance procedures and to station equipment and facilities are made where they should substantially reduce exposures at a reasonable cost;
7. The radiation protection staff understand the origins of radiation exposures in the station and seeks ways to reduce exposures;
8. Adequate equipment and supplies for radiation protection work are provided.

The Station Manager is responsible for the protection of all persons against radiation and for compliance with NRC regulations and license conditions. This responsibility is in turn shared by all supervisors. Furthermore, all personnel are required to work safely and to follow the regulations, rules, and procedures that have been established for their protection.

5 The Duke Power Company, General Office Technical System Manager, Radiation Protection, establishes the Radiation Protection Program including the program for handling and monitoring radioactive material for Oconee that is designed to assure compliance with applicable regulations, technical specifications, and
5 regulatory guides. The General Office Technical System Manager also provides technical guidance and support for conducting this program, reviews the results of the program to determine its effectiveness and modifies it as required based on experience and regulatory changes, to assure that occupational radiation exposure and exposure to the general public are maintained as low as is reasonably achievable.

9 This individual also provides technical assistance to the Executive Vice President, Nuclear Generation, who has management authority to implement the "as low as is reasonably achievable" (ALARA) occupational exposure policy, to which Duke Power Company is committed.

The Station Radiation Protection Manager at Oconee is responsible for conducting the Radiation Protection Program that has been established for the station. The Station Radiation Protection Manager has the duty and the authority to measure and control the radiation exposure of personnel; to continuously evaluate and review the radiological status of the station; to make recommendations for control or elimination of radiation hazards; to assure that all personnel are trained in radiation protection; to assist all personnel in carrying out their radiation protection responsibilities; and to protect the health and safety of the public both on-site and in the surrounding area.

In order to achieve the goals of the Radiation Protection Program and fulfill these responsibilities for radiation protection; radiological monitoring, survey and personnel exposure control work are performed on a continuing basis for station operations and maintenance.

The Radiation Protection Section performs the major portion of the radiation protection work for the
0 station. Personnel in the Radiation Protection Section normally work on the day shift during periods of
0 routine operation; and deploy onto the other shifts for major maintenance, shutdown, and refueling work. A supervisor and several Radiation Protection Technicians are also assigned to each operating shift. The Radiation Protection Section is organized into major areas, such as surveillance and control, support functions, staff and shift.

12.4.1 PERSONNEL MONITORING SYSTEMS

Monitoring instruments are located at exits from the Radiation Control Area. These instruments are intended for use to prevent any contamination on personnel, materials, or equipment from being spread into the unrestricted/secondary systems areas of the station. Appropriate monitoring instruments are also
2 used at various locations throughout the station for contamination control purposes. Portal monitors are utilized as appropriate, to monitor personnel leaving the station.

3 Personnel monitoring equipment consists of thermoluminescent dosimeters (TLD's), electronic
3 dosimeters, or "self-reading" dosimeters which are worn by those persons who ordinarily work in the
4 Radiation Control Area or RCZ. In addition, monitoring devices are readily available for use for
3 measurement of extremity dose. This personnel monitoring equipment is issued by Radiation Protection. Personnel monitoring equipment is also available on a day-to-day basis for those persons, employees or visitors, not assigned to the station who have occasion to enter the Radiation Control Area or to perform work involving possible exposure to radiation.

The use of personnel monitoring equipment mentioned above refers specifically to compliance with
2 10CFR 20.1502. The Station Radiation Protection Manager may require additional equipment to be worn based on the actual or anticipated dose rates and other radiological problems encountered on the job.

2 Personnel monitoring badges are supplied by a centralized in-house personnel dosimetry service which meets all applicable requirements for sensitivity, range, and accuracy of measurement. This service is NVLAP approved. Conformance with appropriate standards is also required. This service has the
2 response capability for both routine and emergency purposes.

A body burden analyzer for routine screening of personnel for internal exposure is provided in the low background counting area in the Administration Building. Outside services for radiobioassay and whole body counting are utilized as required for backup and support of this program. The station equipment is
2 sufficiently sensitive to detect in thyroid, lungs or whole body a few percent of the allowable limit of
2 intake for those gamma emitting radionuclides encountered.

12.4.2 PERSONNEL PROTECTIVE EQUIPMENT

Special "protective" or "anti-contamination" clothing is furnished and worn as necessary to protect personnel against contact with radioactive contamination.

This consists of coveralls, lab coats, hoods, gloves, and shoe covers. Change rooms are conveniently located in the Radiation Control Area of the station for proper utilization of this protective clothing. Approved respiratory protective equipment is also available to supplement process containment and
2 ventilation controls, for the protection of personnel against airborne radioactive contamination. This equipment consists of compressed air systems, air-supplied respirators, air-purifying (filter) respirators and Self-Contained Breathing Apparatus (SCBA).

Maintenance of the respiratory protective equipment is in accordance with the manufacturer's
3 recommendations and NUREG 0041. The use and maintenance of protective clothing and radiological respiratory protective equipment is under the direct control of the Radiation Protection Section and personnel are trained in the use of this equipment before using them in the performance of their work. The use of respiratory protective equipment is in accordance with appropriate regulations (10CFR
3 20.1202, 1204 and 1701-1704) Regulatory Guides and ANSI Standards.

12.4.3 FACILITIES AND ACCESS PROVISIONS

Change room facilities are provided where personnel obtain clean protective clothing and other equipment required for station work. The change rooms serve the Reactor Buildings, the Auxiliary Building, the Spent Fuel Pools, and the Hot Machine Shop. A change room is also provided for female employees. These facilities are divided into clean and contaminated sections. The contaminated section of the change rooms is used for the removal and handling of contaminated protective clothing after use.

Showers, sinks, and radiation monitoring equipment are provided in all of the change rooms to aid in the decontamination of personnel.

Personnel who are required to utilize protective clothing obtain these items in the change rooms. They first enter the change room on the "clean" side, don the required protective clothing, and then proceed to the job location. After completing work, they remove outer contaminated protective clothing at the exit of the Radiation Control Zone set up about the work area. They then proceed to the "contaminated" side of the change room, where they remove inner protective clothing items, monitor themselves; if contaminated contact RP, if clean, proceed to the "clean" side, where they put on their personal clothing before leaving.

2 The personnel entrance/exit points to/from the Auxiliary Building (RCA) are provided with contamination control checkpoints that are equipped with appropriate monitoring instrumentation. All other personnel-access points into the RCA in the Auxiliary Building are protected by restricted-in/free

out doors in case of emergency. Contamination control check-points are strategically placed throughout the RCA to prevent the spread of contamination within this area.

Before leaving the Radiation Control Area, personnel are required to monitor themselves with the appropriate equipment, positioned near each control point exit door, to make sure that they are free of significant contamination.

3

In order to protect personnel from radiation and radioactive materials, the Radiation Control Area of the station is divided into areas of increasingly controlled access depending on radiation levels. Protection of
2 personnel from access to radiation areas, high radiation areas, extra high radiation areas, and very high
2 radiation areas that exist temporarily or permanently as a result of station operations and maintenance is
by means of appropriate radiation warning signs, barricades, locked doors, audible and visual indicators and alarms, etc., as required by 10CFR 20.

All work on systems or in locations where radioactive contamination or external radiation is present requires a specific Radiation Work Permit (RWP) for nonroutine operations, or a Standing Radiation
2 Work Permit (SRWP) for routine operations, prepared under the direction of the Station Radiation
2 Protection Manager before work may begin. The radiological hazards associated with the job are
determined and evaluated prior to issuing the permit whenever practical, and historical data will be used when this is not practical.

Keeping exposures ALARA is a major consideration. The Radiation Work Permit lists the precautions to be taken including, as appropriate, working time limits (for external and internal exposure), protective clothing to be worn, and any radiation monitoring that may be required during the performance of the work. The permit is issued for personnel use. A working copy is maintained by the Radiation Protection Section.

All persons performing radiological work are required to read and understand the instructions on the
0 appropriate RWP/SRWP and to respond to the prompts provided by the Electronic Dose Capture
0 System (EDC), or fill out the required information on their Daily Exposure Time Record dose card
0 before entering and after leaving the RCZ and/or Radiation Control Area if the EDC system is
0 unavailable for use. The information from the EDC system or the dose card is entered into the Radiation
2 Monitoring and Control (RM&C) System computer programs and serves, in part, as a personnel
monitoring record for the individuals involved.

An equipment decontamination facility is provided at the station for large and small items of station equipment, components and tools. In addition, a cask decontamination area is provided adjacent to each spent fuel pool. A decontamination laundry and a respiratory protective equipment cleaning and repair facility are also provided.

Decontamination of work areas throughout the station is facilitated by the provision of janitor's sinks in
9 the reactor containments and on elevations 783 + 9, 796 + 6, and 838 + 0 in the Auxiliary Building.

Drains from all of these facilities go to appropriate radioactive liquid waste drain tanks. Written procedures govern the proper use of protective clothing, the change rooms, and the decontamination facilities.

7 Radioactive material and contaminated equipment associated with plant operations shall be labeled/posted
7 controlled and stored within the Restricted Area and/or the Owner Controlled Area in accordance with

7 10CFR20 requirements until such time that it is appropriate to transfer it to another location licensed to
7 receive such radioactive material.

7 The Reactor Coolant Pump Motor Refurbishment Building is available for maintenance activities that
7 will not release uncontrolled airborne radioactivity to the environment. Controls are imposed by the
7 radiological procedure governing the work to ensure that uncontrolled airborne radioactivity is not
7 released to the environment from the facility. The radiological control procedure will also specify
7 conditions under which work will be performed in an enclosure with a HEPA-filtered exhaust. The
7 HEPA-filtered exhaust will be monitored for the discharge of radioactivity during periods of HEPA
7 system operation.

7 The Carbon Dioxide Blast Facility is available for decontamination activities that will not release
7 uncontrolled airborne radioactivity to the environment. Controls are imposed by the radiological
7 procedure governing the decontamination work to ensure that uncontrolled airborne radioactivity is not
7 released to the environment from the facility. The blast facility is housed within a building that does not
7 exhaust to the environment. Additionally during periods of operation, the process is exhausted through a
7 HEPA filtration unit, to the outer facility. The HEPA-filtered exhaust is constantly monitored for the
7 discharge of radioactivity during periods of HEPA system operation.

12.4.4 RADIATION PROTECTION AND CHEMISTRY FACILITIES

The major Radiation Protection facilities including a shielded counting room are centrally located at the
Oconee 1 and 2 Auxiliary Building interface for efficiency of operation. These facilities are equipped for
4 detecting, measuring, and analyzing radiation(s) of primary concern and for evaluating radiological
4 problems that may be reasonably expected. Portable equipment calibration and respirator maintenance
4 facilities are located at the Oconee 3 Auxiliary Building.

The chemistry facilities located in the auxiliary building include a primary lab and office area located at
the Oconee 1 and 2 Auxiliary Building interface and a secondary lab and office area located in Oconee 3's
Auxiliary Building. The primary lab is used to analyze primary system (reactor coolant, pressurizer,
BWST, etc.) samples while the secondary lab is used to analyze secondary system (feedwater, hotwell,
3 etc.) samples.

The chemistry facilities located outside the auxiliary building include a chemistry laboratory in the Radwaste Facility. The laboratory is used to perform chemical analyses on radwaste samples and to prepare samples for gamma spectra and beta counting.

Body burden analysis measurements for personnel internal dosimetry purposes is performed in the administration building. Environmental samples are collected and sent to a Duke Power Company environmental facility for analysis.

12.4.5 RADIATION PROTECTION INSTRUMENTATION

12.4.5.1 Laboratory and Portable Instruments

The various types of portable and laboratory instruments used in the Radiation Protection program
measure alpha, beta, gamma, or neutron radiation. These instruments are required for measurements to
2 provide protection against radiation for station personnel through surveys required by 10CFR 20.1501; to
analyze and measure radioactivity prior to the release of effluents for the protection of the health and safety of the public; and to provide for all other radioactivity and radiation measurements and analyses necessary for personnel and public safety and for protection of property. They were selected to provide the appropriate detection capabilities, ranges, sensitivities, and accuracies for the anticipated levels of

radiation at Oconee Nuclear Station during normal operation, anticipated transients and emergency conditions. Sufficient quantities are maintained for use, calibration, maintenance and repair.

Portable radiation survey and monitoring instruments for daily routine use are maintained with nominal operational characteristics as indicated below:

2 Beta-gamma survey meters (Geiger counters, nominal 0-50 mrad/hr) are used for detection of radioactive contamination on surfaces and for low level dose rate measurements.

6 Beta/gamma ionization chamber survey meters (nominal 0-50 Rad/hr) are used to cover the range of dose rate measurements necessary for radiation protection purposes.

5 The above mentioned portable instruments are subject to preoperational response checks to low activity
0 Cs-137 sources. Calibrations are performed at least semiannually. The Cs-137 Shepherd calibration sources and the variable pulse generator are also calibrated annually using National Institute of Standards and Technology (NIST) traceable secondary standards.

6 Neutron REM survey instruments (nominal 0-100 rem/hr) are used to measure the sum of thermal, intermediate, and fast neutron dose rates for radiation protection purposes. These instruments are
2 calibrated at least semiannually with a variable pulse generator and source checked using a Pu-Be source.

The laboratory equipment is maintained as indicated below:

Multi-channel analyzers are utilized in conjunction with solid state detectors, for identification and measurement of gamma emitting radionuclides in samples of reactor primary coolant, liquid and gaseous waste, airborne contaminants, etc.

Dual channel liquid scintillation counters are used for counting tritium, as well as gross beta activity, in reactor primary coolant and other radioactive liquids and wastes.

6 Smears for beta/gamma contamination are counted utilizing proportional or GM counter-scalers. Smears
6 for alpha contamination are counted utilizing scintillator or proportional counter-scalers.

3 A shielded body-burden analyzer having adequate sensitivity to detect radionuclides of interest is located in the Administration Building and is used for personnel bioassay purposes.

The counting room equipment is subject to annual calibration/calibration check by NIST traceable
3 sources in addition to daily response checks and routine inter-laboratory cross checks when equipment is
3 in service.

Various portable airborne gaseous, particulates, and iodine samplers are available for routine use to
0 evaluate air contamination. Samplers are calibrated at least semiannually. Magnahelic gauges used for calibration of these samplers are calibrated annually by NIST traceable instruments.

2 Respiratory protective equipment includes air purifying full-face masks, air supplied respirators. Chemical cartridge particulate respirators are also available. All are maintained according to applicable regulations such as those contained in 10CFR Part 20. Respiratory protective equipment is stored in the respirator issue facility, the Control Room(s), the Operations Support Center, and other emergency locations.

Portable instrumentation for use in emergency situations is stored in emergency kits which are located in the Control Room(s) lobby and in the respirator issue facility. The kits are examined periodically for maintenance and calibration.

12.4.5.2 Inplant Radiation Monitoring

Inplant Radiation Monitoring Systems provide station personnel with capabilities to assess the radiological situation in various areas of significance during normal operation as well as during off-normal and emergency situations. The monitoring systems include the Area Radiation Monitoring Systems and the Process Radiation Monitoring System. Portable radiation and air monitoring equipment is also used to supplement these systems.

The Area Radiation Monitoring System is provided to monitor radiation levels in various plant locations that are potential personnel exposure areas. This system consists of gamma sensitive detectors, signal conditioning and readout instrumentation, radiation level alarm sensing logic, audible and visible alarm devices and outputs available for recording. A complete description of the location, sensitivity, and accuracy of this system is presented in Section 12.3.3.2, "Description."

The Process Radiation Monitoring System is provided in part to monitor station effluents that are
potential sources of radioactivity. Also, gases, particulates, and liquid and iodine levels are monitored in
primary and secondary systems during normal operation, anticipated operational occurrences and
emergencies. This system provides an indication of the radioactivity in the process line monitored and
provides alarms in the control room at a preset level to ensure that concentrations are maintained within
0 the limits specified in the DPC Oconee Nuclear Station Selected Licensee Commitments Manual. In
addition some of the monitors perform control functions during postulated accident conditions. A
complete description of the Process Radiation Monitoring System, including its range, sensitivity, setpoint,
and detector type is presented in Section 11.5, "Process and Effluent Radiological Monitoring and
Sampling Systems."

The process and area radiation monitoring systems are supplemented by periodic surveys and by periodic
grab air samples, which are collected and analyzed by Radiation Protection and Chemistry, during normal
7 and abnormal operations and maintenance. Appropriate cartridges are used for sampling air when the
presence of iodine is suspected.

12.4.6 RADIO-BIOASSAY AND MEDICAL PROGRAMS

2 Duke employees and contract service employees issued a personnel monitoring badge and who plan on
3 entering the RCA/RCZ are given a body-burden analysis when the badge is initially issued and when
employment is terminated or alternatively, when the person is transferred to a non-radiological
2 assignment. Visitors who plan on entering the RCA/RCZ are generally given a body-burden analysis
each time a monitoring badge is issued and at the termination of the station visit. In addition, badged
station personnel and appropriate other Duke system personnel participate in a routine body-burden
analysis program which provides for at least one body-burden analysis per year for each participant.
9 Additional body-burden analysis can be required for personnel who experience significant exposure to
9 airborne contamination or other conditions, (such as pregnancy or change in employee status). The
Station Radiation Protection Manager may waive the requirement for any analysis on a case by case basis
if in his judgement, the analysis is inappropriate or impracticable. No special medical examination is
considered to be necessary for radiation workers whose exposure is maintained within permissible dose
limits. However, a pre-employment physical is required of prospective radiation workers to determine
their health status and their ability to perform the job. Also, personnel are also examined or screened by
0 a physician to ensure that they are medically able to use respiratory equipment. Personnel using
0 respiratory equipment are given the appropriate training for respiratory use and fit tested as required for
the respirator(s) to be used.

Anyone onsite, whether badged or not, who is involved in a radiological accident where internal exposure is likely, is given a body-burden analysis as soon as practicable thereafter.

2 Dose commitments are calculated by the Site or General Office Radiation Protection Staff.

Medical observation and treatment are available in case of over-exposure or excessive contamination. Physicians, a medical clinic, and hospital facilities are available for the treatment of injuries. A local physician has been retained, and trained in the care and treatment of radiation injuries, and facilities have been established in a local hospital for the handling and treatment of possibly contaminated injured or irradiated patients. Back-up support is also available through the Oak Ridge Radiation Emergency Assistance Center/Training Site, REAC/TS. Radiation Protection personnel are responsible for the radio-bioassay program and are available to assist the physicians and the hospital in maintaining medical control of over-exposed or contaminated personnel.

These programs are designed to monitor and protect the health of all employees concerned, to confirm the adequacy of the radiation control methods employed at the station and to provide for the treatment of injuries.

12.4.7 TESTS AND INSPECTIONS

Routine radiological monitoring to detect radiation, radioactive contamination, and airborne radioactivity is performed throughout the plant on periodic schedules. Monitoring frequencies are determined by the Station Radiation Protection Manager based upon the actual or potential radiological conditions. Schedules of routine monitoring are issued to the technicians who initial the schedule when the routine is completed. As plant conditions change, the schedule is updated. Radiological surveys are performed before personnel enter potential or actual radiation areas where there is any doubt as to the existing conditions. Radiological surveys are also performed as a backup to routine monitoring when conditions change. All survey and routine monitoring data is recorded and filed in the Radiation Protection files.
8 Retention of survey and monitoring records follows the requirements of 10CFR 20.2103 and the QA
8 Topical Report.

The Radiation Protection Section also performs essentially all of the work necessary to maintain (other than repair) the Counting Room instruments and the portable radiation monitoring instruments. Periodic NIST traceable calibrations, instrument checks and evaluations, and other manual checks are performed. Duke Power Company participates in NRC approved performance testing programs.
7 Electronic/Self-reading dosimeters are subjected to periodic tests and calibration.

Personnel monitoring instrumentation is subjected to a continuing Quality Control Program. The Quality
2 Control Program includes the use of a computer program that compares TLD values and Electronic/
"self-reading" dosimeter totals covering the same monitoring period and lists those correlations that are
2 unacceptable so that effective problem resolution can be performed as necessary, thus helping to maintain
a high level of personnel monitoring equipment performance.

Duties concerning radioactive gaseous and solid waste disposal are performed by the Radiation Protection section. The detailed analyses and records required to characterize the nature of radioactive gaseous waste releases and solid waste disposal are under the control of the Radiation Protection section.

Duties concerning radioactive liquid waste disposal are performed by the Chemistry section. While the analyses of radioactive liquid waste releases are under the control of the Radiation Protection section, the records required to characterize the nature of liquid waste releases, both qualitatively and quantitatively, are under the control of the Chemistry section.

Training and qualification of personnel in Radiation Protection are the responsibility of the Station
2 Radiation Protection Manager and are performed by the Radiation Protection Section, or by Nuclear
2 Generation Department Training personnel, under his direction.

2 The Radiation Protection Section maintains the Offsite Radiological Monitoring Program for the station
2 in conjunction with the Chemistry Section.

THIS IS THE LAST PAGE OF THE CHAPTER 12 TEXT PORTION.

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

CHAPTER 13. CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE

13.1.1 CORPORATE ORGANIZATION

1 The corporate structure of Duke Power Company is shown in Figure 13-1 and Figure 13-2.

13.1.1.1 Corporate Functions, Responsibilities and Authorities

8 The Duke Power Company, division of Duke Energy Corporation, has nearly 91 years of experience in
5 the design, construction and operation of electric generating stations. As of 1994, Duke's total system
5 capacity was approximately 18,000 MWe. Duke operated eight fossil stations with a 38% share of this
5 total capacity, three nuclear steam-electric stations with a 60% share, and 27 hydroelectric stations, four
5 pumped storage units, and combustion turbine and diesel peaking units accounting for the remaining 2%
5 share.

Company involvement in nuclear power began in the early 1950's with various personnel receiving nuclear training. Selected personnel have been involved full time in nuclear projects since the mid-1950's. Duke participated in the Carolinas-Virginia Nuclear Power Associates (CVNPA), which resulted in a 17,000 kWe nuclear steam-electric unit at Parr, South Carolina. This unit, the Carolinas-Virginia Tube Reactor (CVTR), produced electricity over the period 1963 to 1967 as part of a five-year operating research program. Duke's three unit Oconee Nuclear Station began operation in 1973, the two unit McGuire Nuclear Station began operation in 1981, and two unit Catawba Nuclear Station began operation in 1984.
5 As a result of these and other assignments, many personnel in the Duke organization have had prior nuclear experience as well as extensive experience in the power field.

Various departments within the Company have responsibility for design, construction, quality assurance and operation of each nuclear station. Duke contracts with a nuclear steam supply system (NSSS) vendor for the design and manufacture of the complete NSSS. The NSSS vendor also provides technical consultation in areas such as construction, testing, startup and initial fuel loading.

5 Duke's corporate functions, responsibilities and authorities for quality assurance are addressed in Topical
5 Report DUKE-1A.

1 The Chairman of the Board and Chief Executive Officer has overall responsibility for corporate functions
1 involving planning, design, construction and operation of the Company's generation, transmission, and
1 distribution facilities, as well as other staff functions.

5 Line responsibilities relative to Nuclear Generation are delegated through the President and Chief
5 Operating Officer, Power Generation Group, to the Senior Vice President, Nuclear Generation as shown
7 in Figure 13-1, Figure 13-2, and Figure 13-7.

13.1.1.2 Organization for Design and Construction

1

1 Effective November 1, 1991, Duke reorganized to create the Power Generation Group, which includes the
1 Nuclear Generation Department. Separate organizations for design and construction ceased to exist.

13.1.2 OPERATING ORGANIZATION

1 13.1.2.1 Nuclear Generation Department Organization

7 Duke's Nuclear Generation Department, headed by the Executive Vice President, Nuclear Generation, has
1 corporate responsibility for overall nuclear safety, as established by Technical Specifications. Reporting to
7 the Executive Vice President is a Vice President for each nuclear site, and Managers of the Nuclear
5 Engineering Division, Nuclear Assessment and Issues Division, Engineering Support Division, and
7 Nuclear Services Division.

1 The Nuclear Generation Department Organization is shown on Figure 13-3.

1 13.1.2.2 Nuclear Site

1 13.1.2.2.1 Site Organization

1 The nuclear site organization centralizes the resources for safe and efficient nuclear plant operations under
1 a vice president at the nuclear site.

1 The Vice President of Oconee Nuclear site has the responsibility for overall plant nuclear safety as
8 established by Technical Specifications. The Vice President or his designee has the authority to approve
8 all Site Directives and revisions. The site staff is fully capable and equipped to handle all situations
1 involving safety of the station and public. The Nuclear site staff is shown on Figure 13-4.

1 As established by the Duke Quality Assurance Program Topical Report, Duke-1A, anyone involved in
1 quality activities in the Duke organization has the authority and responsibility to stop work if they
1 discover deficiencies in quality.

13.1.2.2.2 Personnel Functions, Responsibilities and Authorities

The functions and responsibilities of key supervisory staff are described in the succeeding paragraphs.

(a) Station Manager

The Station Manager reports to the Vice President, Oconee Site and has direct responsibility for operating the station in a safe, reliable and efficient manner. He is responsible for protection of the station staff and the general public from radiation exposure and/or any other consequences of an accident at the station. He bears the responsibility for compliance with the facility operating license. The Station Manager or his
8 designee shall approve, prior to implementation, each proposed test, experiment, or modification to
8 systems or equipment that affect nuclear safety. The Station Manager or his designee has the authority to
8 approve and issue procedures. The Station Manager is responsible for approval of all proposed changes to
8 the Facility Operating License, Technical Specifications, Technical Specification Bases, and Selected
8 Licensee Commitments.

(b) Operations Superintendent

The Operations Superintendent has the responsibility for directing the actual day-to-day operation of the station. In the event of the absence of the Station Manager, the Operations Superintendent, if so designated, assumes the responsibilities and authority of the Station Manager.

1 **(c) Shift Operations Manager**

4 The Shift Operations Manager is responsible for the overall activities of all the on-shift licensed and
1 non-licensed operating personnel.

4 **(d) Operations Shift Manager**

8 An Operations Shift Manager is the senior licensed individual responsible for the overall operation of the
4 station on his assigned shift. He oversees the activities of the operators on his shift and is cognizant of all
4 maintenance activity being performed while he is on duty. The Operations Shift Manager on duty has
1 both the authority and the obligation to shut down a unit if, in his opinion, conditions warrant this
1 action.

4 **(e) Shift Supervisor**

8 The Shift Supervisor (Control Room SRO) assists the Operations Shift Manager in operation of the
4 station on his assigned shift. The Shift Supervisor on duty has both the authority and the obligation to
1 shut down a unit if, in his opinion, conditions warrant this action.

1 **(f) Reactor Operator**

1 A Reactor Operator is responsible for the actual operation of a Unit on his assigned shift. The Reactor
1 Operator has both the authority and obligation to shut down a unit if, in his opinion, conditions warrant
1 this action.

8 **(g) Non Licensed Operator**

8 A Non Licensed Operator (NLO) is responsible for the operation of equipment outside of the Control
1 Room.

1 **(h) Radiation Protection Manager**

1 The Radiation Protection Manager has the responsibility for conducting the radiation protection program.
1 His duties include the training of personnel in use of equipment, control of radiation exposure of
1 personnel, continuous determination of the radiological status of the station, surveillance of radioactive
1 waste disposal operations, conducting the radiological environmental monitoring program and maintaining
1 all required records. He has direct access to the Station Manager in matters concerning any phase of
1 radiological protection. The Radiation Protection Manager also has direct support as required from the
5 Technical Manager of Radiation Protection in Nuclear Services and his staff.

1 **(i) Chemistry Manager**

1 The Chemistry Manager is responsible for overall chemistry and radiochemistry requirements, with special
1 emphasis on primary and secondary system water chemistry.

4 **(j) Maintenance Superintendent**

4 The Mechanical Superintendent and the I&E Superintendent roles are combined under the title
4 Maintenance Superintendent as long as the Maintenance Superintendent meets the required qualifications
4 under both subtitles.

4 1. Mechanical Superintendent

4 The Mechanical Superintendent has responsibility for maintenance of mechanical equipment.

4 2. I&E Superintendent

4 The I&E Superintendent has responsibility for maintenance of electrical equipment, instrumentation,
9 controls, and programmable logic controllers. (Local Information Technology is responsible for plant

9 computer systems and networks including, but not limited to, the Operator Aid Computer, the
9 Process Monitoring Computer, Plant Security Computer System, and Chemistry data acquisition
9 systems.)

4 **(k) Work Control Superintendent**

1 The Work Control Superintendent manages the station's efforts to support Oconee Nuclear Station's
1 operational and outage activities through the coordination, development, shift and outage management of
1 a timely and effective integrated station schedule.

5 **(l) Shift Work Manager**

8 The Shift Work Manager (who fulfills the role of Shift Technical Advisor (STA)) is responsible for plant
5 accident assessment functions during transients and operations assessment functions during normal
8 operations. The Shift Work Manager provides advisory technical support to the Shift Supervisor in the
8 areas of thermal-hydraulics, reactor engineering, and plant analysis with regard to safe operation of the
8 unit. The Shift Work Manager role may be performed by a qualified SRO assigned to the operating shift.

4 **(m) Safety Assurance Manager**

1 The Safety Assurance Manager is responsible for directing the activities of Regulatory and Environmental
5 Compliance, Safety Review, Emergency Preparedness, INPO Coordinator, and HPES.

4 **(n) Regulatory Compliance Manager**

2 The Regulatory Compliance Manager has responsibility for coordinating station interfaces with regulatory
1 agencies and for providing review of appropriate station technical matters.

5 **(o) Organizational Effectiveness Manager**

5 The Organizational Effectiveness Manager is responsible for coordination of site administrative functions
5 including clerical, personnel, safety, fire protection, security, and medical.

5 **(p) Training Manager**

5 The Site Training Manager is responsible for implementation and oversight of the training programs for
5 site personnel. The Site Training Division provides the analysis, design, development, implementation
5 and evaluation of Training and Qualifications programs in support of personnel performing work in the
5 nuclear station. Furthermore, the Site Training Division ensures station training programs meet or exceed
5 all facility licensing, FSAR, Nuclear Policy or regulatory requirements.

5 **(q) Commodities and Facilities Manager**

5 The Commodities and Facilities Manager is responsible for assuring that the work units provide quality
5 commodities, services, and facility support to their customers.

5 Commodities and Facilities provides acquisition, management, and maintenance services for parts,
5 supplies, tools, equipment, and commercial facilities required for the operation of the nuclear station.
5 Primary objectives are to provide these services and related commodities in a safe and economical manner.
5 Work units include Facilities and Equipment Maintenance, Regional Commodities and Facilities Support,
5 Facilities and Equipment Management, Inventory Management, Commodities/Services Management,
5 Customer Support, and Commodities/Facilities Technical Support.

1 #### 13.1.2.3 Shift Crew Composition

8 The operating shift crew consists of an Operations Shift Manager, a Shift Work Manager, a Control
8 Room SRO in each Control Room, and appropriate licensed and nonlicensed operators. In addition,
Radiation Protection, Chemistry, Maintenance and I&E technicians are on site at all times when there is
fuel in a reactor.

1 #### 13.1.2.4 Nuclear Services Organization

1 The Nuclear Services organizations provide corporate oversight and specific technical services to all Duke
7 Nuclear sites. These organizations are headed by the Executive Vice President, Nuclear Generation. The
1 organization chart is shown on Figure 13-4. The function and responsibilities are described in the
1 succeeding paragraphs.

7 1. G.O. Nuclear Engineering

1 This organization has the responsibility for safety analysis, probabilistic risk assessments, reactor core
1 design, out-of-core fuel management, core thermal hydraulic design, fuel fabrication, and failed fuel
1 analysis.

7 2. Nuclear Services Division

1 This organization provides operating support to all Duke nuclear sites with an emphasis on generic
1 programs and the promotion of consistancy. Support is provided for the areas of Civil and Electrical
1 Engineering, Mechanical and Instrument & Electrical (I&E) Maintenance, Fire Protection, and
7 Mechanical and Electrical Materials Procurement Engineering. This organization is also responsible
7 for providing oversight and technical support in the areas of chemistry, radiation protection, radwaste
7 and radioactive materials control. It also determines and maintains all dosimetry records for Duke
7 Power personnel.

7 3. G. O. Nuclear Assessments & Issues

1 This organization provides oversight and support to assure safe nuclear station operation and
1 compliance with regulatory requirements. Work units include Nuclear Licensing Services, Operational
7 Event Analysis, Emergency Planning, and Environmental Licensing Services. This organization also
7 provides services and leadership which support, and supplement station personnel efforts as they relate
7 to the operation of the station. Primary roles include support of long term development of new
7 programs, policies and technology in the areas of reliability improvement, generic operating issues,
7 system and component performance, and automation projects; as well as support for the development
7 of projects that are not feasible or economical endeavors for the individual station.

8 ### 13.1.3 QUALIFICATIONS OF SITE PERSONNEL

1 The qualifications of personnel in the site organization are in accordance with Section 4 of ANSI
8 3.1-1978, "Selection and Training of Nuclear Power Plant Personnel," with the exception of those for the
8 Superintendent of Operations and the Shift Operations Manager.

8

Replacement personnel for positions in the nuclear stations are fully trained and qualified to fill their
1 appointed positions. Qualifications of key site personnel are available for inspection on site.

13.1.3.1 Minimum Qualification Requirements

The minimum qualification requirements for station personnel are outlined in the succeeding paragraphs.

1 **(a) Station Manager**

The Station Manager shall have a minimum of ten years of responsible nuclear or fossil station experience, of which a minimum of three years shall be nuclear station experience. A maximum of four years of the remaining seven years of experience may be fulfilled by academic training on a one-for-one time basis. To be acceptable, this academic training shall be in an engineering or scientific field generally associated with power production. The Station Manager shall have acquired the experience and training normally required for examination by the NRC for a Senior Reactor Operator license, whether or not the examination is taken.

2 The qualification requirements described above may be reduced in accordance with ANSI/ANS-3.1-1978
2 which states:

> 2 "In an organization which includes one or more persons who are designated as principal alternates
> 2 for the plant manager and who meet the nuclear power plant experience and training requirements
> 2 established for the plant manager, the requirements of the plant manager may be reduced, such
> 2 that only one of his ten years of experience need to be nuclear power plant experience and he
> 2 need not be eligible for the NRC examination."

1 **(b) Operations Superintendent**

8 Refer to Oconee Technical Specification 5.3.1.

1 **(c) Safety Assurance Manager**

1 The Safety Assurance Manager should have a minimum of eight years of responsible nuclear or fossil station experience, of which a minimum of one year shall be nuclear station experience. A maximum of four years of the remaining seven years of experience should be fulfilled by satisfactory completion of academic training.

1

1 **(d) Work Control Superintendent**

1 The Work Control Superintendent shall have a minimum of seven (7) years of responsible nuclear or fossil station experience, or applicable industrial experience, of which a minimum of one (1) year shall be nuclear station experience. A maximum of two (2) years of the remaining six (6) years of experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time
1 basis. The Work Control Superintendent should also have a familiarity with the scheduling and project management techniques used at the Duke nuclear stations, management skills, and an understanding of the Duke administrative policies and procedures.

1 **(e) Shift Operations Manager**

8 See Oconee Technical Specification 5.3.1.

1

1 **(f) Chemistry Manager**

The Chemistry Manager shall have a minimum of five years of experience in chemistry, of which a minimum of one year shall be in radiochemistry. A minimum of two years of this five years of experience should be related technical training. A maximum of four years of this five years of experience may be fulfilled by academic or related technical training.

1 **(g) Radiation Protection Manager**

8 The Radiation Protection Manager shall have a bachelor's degree in a science or engineering subject
8 including some formal training in radiation protection, and shall have at least five years of professional
8 experience in applied radiation protection of which three years shall be in applied radiation protection
8 work in one of Duke Power Company's nuclear stations.

2 **(h) Regulatory Compliance Manager**

2 The Regulatory Compliance Manager shall have a minimum of five years of technical experience, of which a minimum of one year shall be nuclear experience. A maximum of four years of this five years experience may be fulfilled by related technical or academic training.

1

4 **(i) Maintenance Superintendent**

4 The Mechanical Superintendent and the I&E Superintendent roles are combined under the title
4 Maintenance Superintendent as long as the Maintenance Superintendent meets the required qualifications
4 under both subtitles.

4 1. Mechanical Superintendent

The Mechanical Superintendent shall have a minimum of seven years of responsible nuclear or fossil station experience, or applicable industrial experience, of which a minimum of one year shall be nuclear station experience. A maximum of two years of the remaining six years of experience may be fulfilled by satisfactory completion of academic or related technical training on a one-for-one time basis. The Mechanical Superintendent should also have non-destructive testing familiarity, craft knowledge, and an understanding of electrical, pressure vessel and piping codes.

4 2. Instrument and Electrical Superintendent

The Instrument and Electrical Superintendent shall have a minimum of five years of experience in instrumentation and control of which a minimum of six months shall be in nuclear instrumentation and control. A minimum of two years of this five years of experience should be fulfilled by academic or related technical training. A maximum of four years of this five years of experience may be fulfilled by academic or related technical training.

1

5 **(j) Shift Work Manager**

5 A Shift Work Manager shall have a minimum of a Bachelor's degree in an engineering or science
discipline, or a Professional Engineer's license, and four years of nuclear power plant experience. A Shift
5 Work Manager shall hold a Senior Reactor Operator's license.

4 **(k) Other Supervisors Required to Hold an NRC License**

2 Members of the station supervisory staff other than those identified in Section 13.1.3.1(a) through
2 13.1.3.1(j) preceeding who are responsible for directing the actions of operators, technicians or repairmen (e.g., intermediate and first line supervisors), and who are required to hold an NRC license, shall have a high school diploma, or equivalent, and a minimum of four (4) years of responsible nuclear or fossil station experience, of which a minimum of one (1) year shall be nuclear station experience. A maximum of two (2) years of the remaining three (3) years of experience may be fulfilled by academic or related technical training on a one-for-one time basis.

4 **(l) Other Supervisors Not Required to Hold an NRC License**

2 Members of the station supervisory staff other than those identified in Section 13.1.3.1(a) through
2 13.1.3.1(j) preceeding who are responsible for directing the actions of operators, technicians or repairmen (e.g., intermediate and first line supervisors), and who are not required to hold an NRC license, shall have a high school diploma, or equivalent, and a minimum of four (4) years of experience in the craft or discipline supervised.

4 **(m) Operators**

Operators to be licensed by the Nuclear Regulatory Commission shall have a high school diploma, or equivalent, and two (2) years of nuclear or fossil station experience, of which a minimum of one (1) year shall be nuclear station experience. In order to be acceptable for full responsibility in a job, they shall hold a Reactor Operator license.

Operators, whether or not they are to be licensed by the Nuclear Regulatory Commission, should have a high school diploma, or equivalent, and should possess a high degree of manual dexterity and mature judgment. Selection interviews and examinations, bearing a significant relationship to job performance, should be used for operators to aid in determining an individual's ability to progress to high levels of responsibility and for eventual Nuclear Regulatory Commission licensing.

4 **(n) Technicians**

Technicians in responsible positions (i.e., individuals who direct the activities of others, but who are not supervisors) shall have a minimum of two years of experience in their specialty. These personnel should have a minimum of one year of related technical training in addition to their experience.

4 **(o) Maintenance Personnel**

Maintenance personnel in responsible positions (i.e., individuals who direct the activities of others, but who are not supervisors) shall have a minimum of three years of experience in one or more crafts. They should possess a high degree of manual dexterity and ability, and should be capable of learning and applying basis skills in maintenance operations.

1

13.2 TRAINING

13.2.1 GENERAL PROGRAM DESCRIPTION

The principal objective of the Duke Power Company Employee Training and Qualification System
2 (ETQS) is to assure job proficiency of all station personnel involved in safety related work. An effective
2 training and qualification system is designed to accommodate future growth and meet commitments to
and comply with applicable established regulations and accreditation standards.

2 Qualification is indicated by successful completion of prescribed training and demonstration of the ability
2 to perform assigned work or tasks competently. Where required, maintaining a current and valid license
2 issued by the regulating agency establishes the requirements.

5 The Oconee Site Training Manager has overall responsibility for the administration of the Employee
1 Training and Qualification System (ETQS). The Vice President, Oconee site, is responsible for the
1 quality of work performed by individuals at the nuclear site. Line Management is responsible for the
timely and effective development of assigned personnel.

1 Training is analyzed, designed, developed, implemented, and evaluated according to a systematic approach to training. Employees are provided with formal training to establish the knowledge foundation and on-the-job training to develop work performance skills. Continuing training is provided, as required, to maintain proficiency in these knowledge and skill components and to provide further employee development.

The Employee Training and Qualification System is designed to prepare initial and replacement station
personnel for safe, reliable and efficient operation of the nuclear facility. The program is intended to meet
2 or exceed INPO accreditation standards and Nuclear Regulatory Commission requirements.

Appropriate training for personnel of various training and experience backgrounds is provided. The level at which an employee initially enters the training and qualifications system for the particular area is determined by an evaluation of the employee's past experience and level of ability.

13.2.1.1 Regulatory Requirements

The applicable portions of the NRC regulations, regulatory guides, and reports listed below will be used in providing guidance in plant staffing and training.

1
- 10CFR PART 50 "Domestic Licensing of Production and Utilization Facilities"
- 10CFR PART 55 "Operators' Licenses" including Appendix A
- 10CFR PART 19 "Notices, Instructions and Reports to Workers; Inspections"
- Regulatory Guide 1.8 "Personnel Selection and Training"
- NRC "Operator Licensing Guide," NUREG-0094, July 1976
- "Utility Staffing and Training for Nuclear Power," WASH-1130, USAEC Revised 1973
- NUREG-0654
- Regulatory Guide 8.2 "Guide for Administrative Practices in Radiation Monitoring"

- Regulatory Guide 8.8 "Information Relevant to maintaining Occupational Radiation Exposures as Low as Reasonably Achievable (Nuclear Power Reactor)"
- Regulatory Guide 8.13, "Instructions Concerning Prenatal Radiation Exposure"
- NUREG-0737

1 • 10 CFR Part 20, "Standards for Protection Against Radiation"

13.2.2 PROGRAM DESCRIPTION

Station assigned personnel may be trained and qualified through participation in prescribed parts of the Employee Training and Qualification System which consists of the following:

General Employee Training

Technical Training

Employee/Professional Development Training

13.2.2.1 General Employee Training

General Employee Training (GET) encompasses those general administrative, safety, emergency and
5 control procedures established by site management and applicable regulations. A summary description of
9 plant systems and equipment is provided. All persons under the supervision of site management and
9 requiring unescorted access to the nuclear facility's protected area must participate in General Employee
9 Training. However, certain station support personnel, depending on their normal work assignment, may
not participate in all topics. Certain portions of General Employee Training may be included in an
9 employee orientation program. Temporary maintenance and service personnel requiring unescorted access
9 to the nuclear facility's protected area must participate in General Employee Training to the extent
necessary to assure safe execution of their duties.

1 All persons regularly employed at the nuclear power plant and under the supervision of site management,
9 and requiring unescorted access to the nuclear facility's protected area, receive training in the following
5 areas commensurate with the level of knowledge required for their job duties.

a. General administrative control and quality assurance policies and procedures

b. Plant systems and equipment

c. Radiological safety including the use of protective clothing and equipment

d. Industrial health, safety and first aid

e. Emergency plan and procedures

f. Station security program and procedures

g. Fire protection program and procedures

5 h. New Employee Orientation

1 i. Environmental compliance overview

2 j. Fitness for Duty

2 k. Respiratory Protection and Fit Testing

Continuing training is conducted in these areas as necessary to maintain employee proficiency.

13.2.2.1.1 Fire Brigade Training

1 The primary purpose of the Fire Brigade Training Program is to develop a group of site employees skilled
9 in fire prevention, fire fighting techniques, and emergency response. They are trained and equipped to
1 function as a team for the fighting of fires. The site fire brigade organization is intended to be
self-sufficient with respect to fire fighting activities.

The Fire Brigade Training program provides for initial training of all new fire brigade members, quarterly classroom training and drills, annual practical training, and leadership training for fire brigade leaders.

13.2.2.2 Technical Training

1 Technical training is designed, developed and implemented to assist site employees in gaining an
understanding of applicable fundamentals, procedures, and practices; and in developing manipulative skills
necessary to perform assigned work in a competent manner. Technical training may consist of three
segments:

Initial Training

On-the-job Training and Qualification

Continuing Training

13.2.2.2.1 Initial Job Training

Initial job training is designed to provide knowledge of the fundamentals, basic principles, and procedures involved in work to which an employee is assigned.

2 This training may consist of, but is not limited to, live lectures, taped and filmed lectures, computer based
2 training, guided self-study, demonstrations, laboratories and workshops, on-the-job training, and where
applicable, simulator training and/or training on a research reactor.

2 New employees or employees transferred from other division locations may be partially qualified by
reason of previous applicable training or experience. The extent of further training for these employees is
determined by applicable regulations, performance in review sessions, comprehensive examinations, or
other techniques designed to identify the employee's present level of ability.

1 Initial job training and qualification programs are developed for Operations, I&E, Mechanical
2 Maintenance, Radiation Protection, and Chemistry non-exempt classifications. Engineering Support
2 position-specific training for newly hired or transferred engineers and other selected technical staff
2 personnel is provided to guide and document development of knowledge and skills needed for activities
2 that could have a significant effect on safe and reliable plant operation.

2 The training programs for technicians include Non-licensed Operator, Mechanical Maintenance,
4 Instrument and Electrical, Operations Test, Radiation Protection and Chemistry. These training
2 programs are accredited by the Institute of Nuclear Power Operations. The Basic Training program is
2 typically divided into three modules: Power Plant Fundamentals, Station Familiarization/Initial Plant
Systems, and Fundamentals (Section Specific).

2 All technician training program attendees share the Power Plant Fundamentals module. This module
includes an introduction, mathematics, physical science, manuals and publications, systems, and
components. A brief description of the rest of the modules in the Initial Training Program for
4 Mechanical Maintenance, Instrument and Electrical, Operations Test, Radiation Protection and
2 Chemistry is as follows:

1. Mechanical Maintenance Initial Training

   a. Power Plant Fundamentals

   b. Plant Orientation Program

		Program Component	Setting	Content
1				
1	1)	Station Familiarization	In Plant	Orientation to plant layout
1	2)	Fundamentals (Shop)	Classroom - Laboratory	Topics may include: -Administration -Maintenance Management -Safety -Dimensional Metrology -Basic Metallurgy -Fasteners -Hand/Portable Power Tools -Basic Machine Shop Practices -Basic Piping/ Maintenance -Rigging/Weight Handling -Antifriction Bearing Maint. -Drawings -Industrial Hydraulics -Mechanical Drives -Gaskets, Packing, and Seals -Valve Maintenance -Welding -Machining 2 -Pumps
1	c.	On-The-Job Training	In Plant	Completion of Training and Qualification (T&Q) Guides

2. Instrument and Electrical

   a. Power Plant Fundamentals

   b. Plant Orientation Program

		Program Component	Setting	Content
1	1)	Station Familiarization	In-Plant	Orientation to plant layout
1	2)	Fundamentals (Basic Instrument/ Electrical)	Classroom - Laboratory	Topics may include: -Basic Electricity -Basic Electronics -Operational Amplifiers -Digital Electronics -Micro-processors -Soldering -Instrumentation and Control Methods -Process Control -Process Control Applications -Electrical -Electrical Valve Actuator Maintenance -Nuclear Instrumentation -Nuclear Safety Systems -Nuclear Non-Safety Systems
1	c.	On-The-Job Training	In Plant	Completion of Training and Qualification (T&Q) Guides

8 3. Operation's Testing

a. Power Plant Fundamentals

		Program Component	Setting	Content
1 5	b.	Station Familiarization/ Initial Plant Systems	In Plant	Orientation to plant systems function, layout
1 1 1	c.	Fundamentals (Basic Performance)	Classroom - Laboratory	Topics may include: -Thermal Science -Component Principles -Inservice Testing -Leak Rate Testing -Basic Electrical -Pre-Lab -Instrumentation and Controls Measuring Methods
1	d.	On-The-Job Training	In Plant	Completion of Training and Qualification (T&Q) Guides

4. Radiation Protection

a. Power Plant Fundamentals

		Program Component	Setting	Content
1	b.	Station Familiarization	In-Plant	Orientation to plant layout
1	c.	Initial Plant Systems	In-Plant	Structured Orientation to plant systems, their function, and physical layout in plant
1	d.	Fundamentals of Radiation Protection	Classroom - Laboratory	Topics may include: -Administration -RP Theory -RP Applications
1	e.	On-The-Job Training	In-Plant	Completion of Training and Qualification (T&Q) Guides

5. Chemistry

		Program Component	Setting	Content
	a.	Power Plant Fundamentals		
1 1	b.	Station Familiarization	In-Plant	Orientation to plant layout
1	c.	Initial Plant Systems	In-Plant	Structured Orientation to plant systems, their function, and physical layout in plant
1	d.	Fundamentals (Chemistry)	Classroom - Laboratory	Topics may include: -Administration -Chemical Principles -Systems -Process Instrumentation -Radioactive Waste System -Laboratory
1	e.	On-The-Job Training	In-plant	Completion of Power and Radwaste Training and Qualification (T&Q) Guides

1 6. Engineering Support Initial Training

This program is accredited by the Institute of Nuclear Power Operations.

1 a. Station Orientation enables the Engineering Support Personnel at ONS to become familiar with plant layout, and roles and responsibilities of each section in the plant. Orientation is conducted
4 using a Task List that identifies training requirements/objectives for each area.

2 b. Fundamentals Training provides a basic understanding of how electricity is generated in a power
2 plant, the conversion and transfer of energy into the ultimate product, basic reactor theory,
2 chemistry, process control systems, and components.

2 c. Systems Training covers normal and emergency purposes, components, and flowpaths of
1 site-specific systems. The course includes specific modules covering Core Damage Mitigation that
1 meet the intent of INPO Guidelines.

4 d. Position Specific Guides

13.2.2.2.2 On-the-Job Training and Qualification

On-the-job training is a systematic method of providing the required job related skills and knowledge for a
4 position. The Qualification process consists of three steps: 1) Training conducted in the work
4 environment/simulated work environment by qualified OJT trainers; 2) an independent evaluation; and 3)
4 a signature by the trainee's supervisor or a member of management awarding qualification. Applicable tasks and related procedures make up the OJT/qualifications program for each technical area which is

designed to supplement and compliment training received through formal classroom, laboratory, and/or simulator training. The objective of the program is to assure the trainee's ability to perform job tasks as described in the task descriptions and the Training and Qualification Guides.

13.2.2.2.3 Continuing Training

1 Continuing Training is any training not provided as Initial Qualification and Basic Training or training
which maintains and improves job-related knowledge and skills such as the following:

a. Plant Systems and Component Changes

b. OJT/Qualification Program Retraining/Requalification

c. Procedure and Directive Changes

d. Operating Experience Program Documents Review to include Industry and In-House Operating Experiences

e. Continuing Training required by Regulation (Emergency Plan Training, etc.)

f. General Employee, Special, Administrative, Vendor, and/or Advanced Training topics supporting tasks.

g. Training identified to resolve deficiencies (task-based) or to reinforce seldom used knowledge and skills

h. Refresher training on initial training topics

i. Structured pre-job instruction, mock-up training, walk-throughs, etc.

5 "Requalification" is a term used in the Operations Training Programs. While requalification training and
5 continuing training may share some similarity in definition, requalification-type training is more clearly
5 associated with the well defined and structured topical areas which are periodically re-taught to the
5 Operations crews to ensure they maintain operating proficiency.

Continuing Training may consist of formal and informal components. Each Section or Division's
5 Continuing Training Program is developed using a systematic approach that includes job performance
5 information from a job and task analysis, and safe operation, as the basis for determining the content of
continuing training. Continuing training may be offered, as needed, on any of the topics or programs listed in Section 13.2.2.2.3, "Continuing Training."

Once the objectives for Continuing Training have been established, the methods for conducting the
2 training may vary. The method selected should provide clear evidence of objective accomplishment and
consistency in delivery.

13.2.2.3 Employee Development and Management/Supervisory Training

Training that falls outside of the scope of Technical Training and General Employee Training is considered to be either Employee Development or Management/Supervisory Training.

Employee Development or Management/Supervisory Training may consist of various classes for different
1 management personnel levels. An individual's training and development will depend on his/her position
description and nomination by management.

13.2.3 OPERATOR LICENSE TRAINING

Duke Power Company's reactor operator and senior reactor operator training and requalification programs are based upon "a systematic approach to training" as defined by 10CFR55.4. These training programs were initially accredited by the Institute of Nuclear Power Operations and the National Nuclear
1 Accrediting Board on August 17, 1983. They received accreditation renewal January 28, 1988 and
1 February, 1992. Pursuant to 10CFR55.31 (a)(4), 10CFR55.59 (c), and Generic Letter 87-07 certification
5 of these training programs' accreditation has been made to the NRC.

13.2.3.1 Operations Initial Training

The initial training program for operators is outlined in the Duke Power Company-Employee Training and Qualifications System Standard 2301.0 "Operations Training and Qualifications Overview." This initial training program provides the trainee with the necessary concepts of nuclear power plant systems, plant operation, mathematics, physics, thermodynamics, fluid flow, nuclear physics, radiation protection and instrumentation and control.

13.2.3.2 Operator License Training

The training for reactor operator and senior reactor operator replacement is based upon a "systematic approach to training" and is described in the Duke Power Company - Employee Training and Qualifications System Standards 2303.0 "License Preparatory Reactor Operator Program" and 2304.0 "License Preparatory Senior Reactor Operator Program."

13.2.3.3 Licensed Operator Requalification Training

Licensed operator requalification training is designed based upon "a systematic approach to training" to maintain and demonstrate continued competence of all licensed operators. The training is described in the Duke Power Company - Employee Training and Qualifications System Standard 2306.0 "Periodic Training Licensed Operator Requalification."

13.2.4 TRAINING PROGRAM EVALUATION

5 Training and qualifications activities are monitored by the Site Training Division. Regulatory Audits,
5 NAID, Division audits site Employee Training and Qualification System. Trainees and vendors may
5 provide input concerning training program effectiveness. Methods utilized to obtain this information may
5 be surveys, questionnaires, performance appraisals, staff evaluation, overall training program effectiveness
5 evaluation instruments, etc. Frequently conducted classes are not evaluated each time; however, they are
5 evaluated at a frequency sufficient to ensure program effectiveness. Evaluation information may be collected through:

- verification of program objectives as related to job duties for which intended;
- 1 testing to determine student accomplishment of these objectives;
- student evaluation of the instruction;
- instructor evaluations of the students;
- 5 supervisor's evaluation of trainee performance on the job, following the training;
- 5 supervisor's evaluation of the instructor; or
- 1 periodic working (review) group evaluation.

The performance and competency of Licensed Reactor Operators and Senior Reactor Operators is evaluated as described in the Duke Power Company-Employee Training and Qualification System
9 Standard No. 2306.0 "Periodic Training Licensed Operator Requalification."

13.2.5 TRAINING AND QUALIFICATIONS DOCUMENTATION

5 Records are maintained on each employee's participation in training activities. It is the Site Training
5 Manager's responsibility to ensure training records are accurate and retrievable.

1 Records shall be retained according to the requirements established by Duke Power Company Employee
9 Training and Qualification System Standard No. 204.0, "Documentation of Training and Qualification of
9 Personnel Who Perform Work at Nuclear Stations Operated by Duke Power."

Documentation associated with Licensed Operator training and Requalification is maintained according to the requirements established by the Duke Power Company-Employee Training and Qualification System Standards No. 2303.0 "License Preparatory Reactor Operator Program," No. 2304.0 "License Preparatory Senior Reactor Operator Program," and No. 2306.0 "Periodic Training Licensed Operator
5 Requalification."

1

13.3 EMERGENCY PLANNING

3 The Emergency Program for the Duke Power Company's Oconee Nuclear Site consists of the Oconee
3 Nuclear Site Emergency Plan and related implementing procedures. Also included are related radiological
3 emergency plans and procedures of state and local governments. The purpose of these plans is to provide
3 protection of plant personnel and the general public and to prevent or mitigate property damage that
3 could result from an emergency at the Oconee Nuclear Site. The combined emergency preparedness
3 programs have the following objectives:

3 1. Effective coordination of emergency activities among all organizations having a response role.

3 2. Early warning and clear instructions to the population-at-risk in the event of a serious radiological
3 emergency.

3 3. Continued assessment of actual or potential consequences both on-site and off-site.

3 4. Effective and timely implementation of emergency measures.

3 5. Continued maintenance of an adequate state of emergency preparedness.

3 The Emergency Plan has been prepared in accordance with Section 50.47 and Appendix E of 10CFR Part
3 50. The plan shall be implemented whenever an emergency situation is indicated. Radiological
3 emergencies can vary in severity from the occurrence of an abnormal event, such as a minor fire with no
3 radiological health consequences, to nuclear accidents having substantial onsite and/or offsite
3 consequences. In addition to emergencies involving a release of radioactive materials, events such as
3 security threats or breaches, fires, electrical system disturbances, and natural phenomena that have the
3 potential for involving radioactive materials are included in the plans. The plan contains adequate
3 flexibility for dealing with any type of emergency that might occur.

3 The activities and responsibilities of outside agencies providing an emergency response role are detailed in
3 the State of South Carolina emergency plans and the emergency plans for Oconee and Pickens Counties.

3 The emergency response resources available to respond to an emergency consist of the following: 1. ONS
3 Site Personnel, 2. Duke Power corporate headquarters personnel, 3. Other Duke Power nuclear station
3 personnel, and, in the longer term, federal emergency response organizations (e.g. NRC, DOE, FEMA).
3 The first line of defense in responding to an emergency lies with the normal operating shift on duty when
3 the emergency begins. Therefore, members of the Oconee staff are assigned emergency response roles that
3 are to be assumed whenever an emergency is declared. The overall management of the emergency is
3 initially performed by the Shift Operations Manager until he/she is relieved by the Station Manager. In
3 the event of an emergency, he serves as the Emergency Coordinator. Onsite personnel have preassigned
3 roles to support the Emergency Coordinator and to implement his directives.

3 Special provisions have been made to assure that ample space and proper equipment are available to
3 effectively respond to the full range of possible emergencies. The emergency facilities available include the
3 Oconee Control Room, Operational Support Center, Technical Support Center, Joint Information
3 Center, and the Emergency Operations Facility. These facilities are described in the site emergency plan.

3 Emergency plan implementing procedures define the specific actions to be followed in order to recognize,
3 assess, and correct an emergency condition and to mitigate its consequences. Procedures to implement the
3 Plan provide the following information:

3 1. Specific instructions to the plant operating staff for the implementation of the Plan.

3 2. Specific authorities and responsibilities of plant operating personnel.

3 3. A source of pertinent information, forms, and data to ensure prompt actions are taken and that
3 proper notifications and communications are carried out.

3 4. A record of the completed actions.

3 5. The mechanism by which emergency preparedness will be maintained at all times.

13.4 REVIEW AND AUDIT

In matters of nuclear safety, both onsite and off-site review of station startup, operation, maintenance, and technical matters is performed. Offsite review is performed by the Nuclear Safety Review Board (NSRB),
5 whereas onsite review is performed by the Safety Review Group (SRG) and by other designated, qualified individuals. This review process commences at least six months prior to the initial operation of a station, so as to include preoperational testing and checkout of the station. Guidance in the development of the review program for test and operation is derived from ANSI N18.7-1976, Administrative Controls for Nuclear Power Plants.

13.4.1 ONSITE REVIEW

Qualified individuals from the station supervisory staff are assigned to review procedures, procedure changes, Technical Specifications changes, and plant modifications involving nuclear safety. These
1 individuals are previously designated to perform these reviews. The final approval of the above reviews is by the Station Manager or other senior station management. In addition, for each review conducted, a determination is made as to whether or not additional cross-disciplinary review is necessary. If concluded that it is necessary, the additional review would be performed by the appropriate designated station review personnel.

4 The Site Vice President appoints a Plant Operations Review Committee (PORC) to review selected
4 nuclear safety related issues. The PORC is composed of specified senior members of the site management
4 team most responsible for the safe and reliable operation of the station. The PORC also reviews the
4 effectiveness of corrective actions taken for specified reportable events.

4 In general, any issue that has the potential to significantly impact safe and reliable nuclear operations, and
4 may benefit from a cross disciplinary review at the site management level, is within the scope of the
4 PORC. The PORC has the following general responsibilities:

4 1. Reviews Justifications for Continued Operation.

4 2. Reviews situations where station structures, systems, or components are determined to be operable,
4 but degraded, and the resulting compensatory actions. On a selected basis, reviews operability
4 determinations that have resulted in the conclusion that station structures, systems, or components are
4 fully operable.

4 3. Reviews pre-job briefings and management oversight plans.

4 4. Reviews reactor restart decisions.

4 5. Reviews independent review team outage assessment results and resulting contingency plans.

4 6. Reviews proposed Technical Specifications/License amendments.

4 7. Reviews Technical Specifications interpretation proposals.

4 8. On a selected basis, reviews reportable events documentation such as Licensee Event Reports, NRC
4 Violation Responses, Station Reports, and reports of unplanned onsite releases of radioactive material
4 to the environs.

4 9. On a selected basis, reviews evaluations performed pursuant to 10CFR50.59.

1 Incident investigation including LERs and special reviews are performed by the SRG or other designated qualified individuals.

13.4.2 INDEPENDENT REVIEW

13.4.2.1 Offsite

The Nuclear Safety Review Board (NSRB) is established to verify that the operation of a station is performed in a safe manner consistent with Company policy, approved operating procedures and license provisions; to review important proposed station modifications, tests, and procedures; to verify that reportable occurrences are promptly investigated and corrected in a manner which reduces the probability of occurrence; and to detect trends which may not be apparent to a day-to-day observer. The Board
8 reports its findings and recommendations to the Executive Vice President, Nuclear Generation.

The membership of the NSRB collectively has the competence required to review problems in the following areas: Nuclear power station operations, nuclear engineering, chemistry, radio-chemistry, metallurgy, instrumentation and control, radiological safety, mechanical engineering, electrical engineering, and administrative control and quality assurance practices. The NSRB is composed of no less than five persons, of whom no more than one is a member of the station organization. A quorum consists of three members and must include either the Director or his designated alternate.

Formal meetings are held at least semi-annually. More frequent meetings are held if necessary.

8 Minutes of meetings are prepared and distributed to the Senior Vice President, Nuclear Generation and
8 the Site Vice President. The NSRB has the following general responsibilities:

a. Review safety evaluations for (1) changes to procedures, equipment, or systems, and (2) tests or experiments completed under the provisions of 10 CFR 50.59 (a) (1), to verify that such actions did not constitute an unreviewed safety question.

b. Review proposed changes to procedures, equipment, or systems which involve an unreviewed safety question as defined in 10 CFR 50.59.

c. Review tests or experiments which involve an unreviewed safety question as defined in 10 CFR 50.59.

d. Review proposed changes in Technical Specifications or Facility Operating Licenses.

e. Review violations of applicable statutes, codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance.

f. Review significant operating abnormalities or deviations from normal, and expected performance of station equipment that affect nuclear safety.

g. Review incidents that are the subject of non-routine reports submitted to the Commission.

4 h. Review NAID, Regulatory Audits Group audits relating to station operations, and actions taken in response to these audits.

Audits of station activities are performed by and under the cognizance of the NSRB. These audits encompass such items as:

a. The conformance of station operation to provisions contained within the Technical Specifications and applicable Facility Operating License conditions.

b. The performance, training, and qualifications of the station staff.

c. The results of actions taken to correct deficiencies occurring in equipment, structures, systems, or methods of operation that affect nuclear safety.

d. The performance of activities required by the quality assurance program to meet the criteria of Appendix B to 10 CFR 50.

e. The station emergency plan and implementing procedures.

f. The station security plan and implementing procedures.

13.4.2.2 Onsite

5 The Safety Review Group (SRG) is established for the purpose of independently examining and making recommendations to management on plant operating characteristics, NRC issuances, Licensing information Advisories, and other appropriate sources of plant design and operating experience
3 information that may indicate areas for improving plant safety. This is accomplished by performing
3 independent reviews of plant activities including maintenance, modifications, operational problems, and
3 operational analyses, and aiding in the establishment of program requirements for plant activities. The
3 SRG verifies and reports on plant operations and maintenance activities and that human errors are
3 reduced as far as practical. The SRG performs incident investigations and the required reports as assigned
3 by the station organization. Periodically the SRG advises the station and corporate management on the
3 overall quality and safety of plant operations. Other information on the conduct of operation of the SRG
3 is provided in SRG procedures.

5 The Safety Review Group (SRG) is an independent review group, located onsite, and reporting to the
1 Manager, Safety Assurance. It is composed of a permanent manager and a minimum of four members.
9 Qualifications of all members are as specified in Section 17.3.3.2.4 of the QA Topical Report.

13.4.3 AUDIT PROGRAM

4 Operational quality assurance activities are periodically audited by the NAID, Regulatory Audits Group. A detailed description of this audit program is contained in Topical Report, DUKE-1A.

The Nuclear Safety Review Board is also responsible for audits of certain operating activities as discussed in Section 13.4.2, "Independent Review."

13.4.4 OPERATING EXPERIENCE PROGRAM

The purpose of the Operating Experience Program (OEP) is to confirm nuclear safety and to optimize reliability through systematic evaluation of events occurring at Duke Power Company nuclear units, as well as at other facilities. This evaluation serves to verify that plant response was as expected during events and transients, and assures that any unexpected behavior is investigated thoroughly and is well understood. The results of this evaluation are then used to identify procedural and/or design changes which may mitigate or preclude the recurrence of a similar event or transient. In order to assure that the program is truly effective, information gained from Duke Power Company experience is disseminated to other organizations, as appropriate.

In order to achieve the objectives of the OEP in an efficient manner, an offsite organization has been established, as well as an on-site organization at each of the nuclear stations.

The on-site organization includes the Station Manager, who is responsible for the operation and safety of the plant; the Station Safety Review Group (SRG), which prepares reports on events and reviews the adequacy of corrective actions; and the supervisors of areas relevant to an event, who may perform the initial investigation and must implement corrective actions.

The off-site organization consists of principal engineering support groups, who interface with station personnel and other organizations in investigating events and developing remedial actions; company management, who holds overall responsibility for nuclear plant safety; and the Nuclear Safety Review Board (NSRB) which performs an independent review function.

13.5 STATION PROCEDURES

13.5.1 ADMINISTRATIVE PROCEDURES

13.5.1.1 Conformance With Regulatory Guides

1 Regulatory Guide 1.33, "Quality Assurance Program Requirements," and ANSI N18.7-1976, "Standard for Administrative Controls for Nuclear Power Plants" shall be used for the preparation of administrative and plant procedures.

13.5.1.2 Preparation of Procedures

For operating, emergency, maintenance, instrument, periodic test, chemistry, radioactive waste management, radiation protection, emergency preparedness, and modification procedures, each procedure is assigned to a member of the station staff for development. Initial procedure drafts are reviewed by
1 members of the station staff, the Nuclear Generation Department General Office, and other departments within Duke, personnel from the NSSS supplier, and other vendors as appropriate. Following resolution of review comments, if any, a revised procedure is prepared and forwarded to a previously designated qualified reviewer for review and comment. This qualified reviewer also makes the determination whether or not any additional, cross-disciplinary review is required. After all required and appropriate reviews
1 have been completed a final version of a procedure is prepared. Upon approval by the responsible
1 implementing manager as previously designated, a procedure becomes available for use. Additional
1 discussion of procedure preparation control is contained in "Quality Assurance Program," Topical Report, DUKE-1A and in the Technical Specifications.

Administrative, annunciator response, security, and material control procedures are prepared by qualified
5 personnel, reviewed as necessary, and approved by the station Manager or his designee prior to use.

13.5.1.3 Administrative Procedures

2 Station administrative procedures are written as necessary to control station testing, maintenance, and operating activities. Listed below are several areas for which administrative procedures are written, including principle features:

13.5.1.3.1 The Reactor Operator's Authority and Responsibility

The reactor operator is given the authority to manipulate controls which directly or indirectly affect core reactivity, including a reactor trip if he deems necessary. He is also assigned the responsibility for knowing the limits and setpoints associated with safety-related equipment and systems as specified in the Technical Specifications and designated in the operating procedures.

13.5.1.3.2 The Senior Reactor Operator's Authority and Responsibility

The senior reactor operator, in addition to the authorities and responsibilities described for the reactor operator, is given the authority to direct the licensed activities of the reactor operator, and ultimately is held responsible for all licensed activities at the station within his control.

13.5.1.3.3 Activities Affecting Station Operation or Operating Indications

9 Prior to removing any instrumentation or controls from service, station personnel shall notify the Work
9 Control Center SRO (WCC SRO). The WCC SRO ensures appropriate notifications of work that may
9 affect unit operations or control room indications are made to the Control Room SRO.

9 The WCC SRO is the primary contact for both outage and innage work.

13.5.1.3.4 Manipulation of Facility Controls

No one is permitted to manipulate the facility controls who is not a licensed reactor operator or senior reactor operator, except for license trainees operating under the direction of a licensed operator. The licensed operators are required to comply with the requalification program as described in Section 13.2, "Training."

Operations Management Procedures are written that delineate the responsibilities of the reactor operators on the control board and the responsibilities of the senior reactor operator in the Control Room. When Technical Specifications require one (1) man in the Control Room (at the controls) this is defined as: Must be in visible line of Nuclear Instrumentation. See cross hatched area on Figure 13-5 and
8 Figure 13-6. One (1) R.O. will be "at the controls" as defined above and the second R.O. will be inside
the CAD key doors that are used for entering and exiting the Control Room.

13.5.1.3.5 Responsibility for Licensed Activities

Responsibility for directing the licensed activities of licensed operators is assigned to individuals with senior reactor operator licenses by virtue of their position within the station organization.

13.5.1.3.6 Relief of Duties

This procedure provides a detailed checklist of applicable items for shift turnover.

13.5.1.3.7 Equipment Control

Equipment control is maintained and documented through the use of tags, labels, stamps, status logs, or other suitable means.

13.5.1.3.8 Master Surveillance Testing Schedule

This procedure establishes a master surveillance testing schedule to assure that required testing is performed and evaluated on a timely basis. Surveillance testing is scheduled such that the safety of the station is not dependent on the performance of a structure, system, or component which has not been tested within its specified testing interval. The master surveillance testing schedule identifies surveillance and testing requirements, applicable procedures, and required test frequency. Assignment of responsibility for these requirements is also indicated.

13.5.1.3.9 Log Books

The following log books are maintained and reviewed by appropriate personnel:

1. Switchboard Record - This document contains data on station and unit electrical power generation, bus voltages, etc.
5 2. Operations Logbook - This document contains documentation of significant events occurring each
5 shift. Examples include reactivity changes, alarms received, abnormal conditions of operation due to

5 auxiliary equipment and all releases of radioactive waste. It contains a summary of unit operation for
5 each shift. Entries are made by Reactor Operators and/or Senior Reactor Operators.

13.5.1.3.10 Temporary Procedures

The use of temporary procedures is discussed in Section 13.5.2.1.3, "Temporary Operating Procedures."

13.5.1.3.11 Fire Protection Procedures

9 Fire protection procedures are written to address such topics as: periodic testing and surveillance,
9 maintenance activities, control of combustibles, fire impairments, hot work authorization, training of the
9 fire brigade, reporting of fires, and control of fire stops. The fire protection engineer in Engineering has
9 responsibility for fire protection procedures in general. All fire protection related procedures and programs
9 contain either an initial review or a subsequent review when the content changes affects a fire technical
9 requirement; however procedural ownership is dependent upon the implementing group such as:
9 Maintenance, Operations, Commodities & Facilities, and Station or General Office Engineering.

13.5.2 OPERATING AND MAINTENANCE PROCEDURES

13.5.2.1 Operating Procedures

13.5.2.1.1 System Procedures

Operating activities which affect the proper functioning of the station's safety-related systems and components are performed in accordance with approved, written procedures. These procedures are intended to provide a pre-planned method of conducting operations of systems, in order to eliminate errors due to on-the-spot analyses and judgements.

Operating procedures are sufficiently detailed that qualified individuals can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and operating procedures, therefore, contain a degree of flexibility appropriate to the activities for which each is applicable.

Typical activities addressed by operating procedures are:

Auxiliary Building Ventilation System Operation
Emergency Feedwater System Operation
Boron Recycle System Operation
Chemical and Volume Control System Operation
Component Cooling Water System Operation
Condensate and Feedwater Systems Operation
Condenser Circulating Water System Operation
Reactor Building Ventilation System Operation
Reactor Building Spray System Operation
Control Room Ventilation System Operation
Degasification of the Reactor Coolant System
Demineralizer Resin Removal and Replacement
Electrical Systems Operation
Failed Fuel Detection and Handling
Filling and Draining of the Refueling Canal
Filling, Venting and Draining of the Reactor Coolant System
Fire Protection Systems Operation

Instrument Air System Operation
Low Pressure Service Water System Operation
Nitrogen System Operation
Nuclear Fuel Control and Accountability
Reactor Coolant Pump Operation
Receipt, Inspection and Storage of New Fuel
Recirculated Cooling Water System Operation
DHR Cooling System Operation
Injection System Operation
1 Spent Fuel Pool Cooling and Purification System Operation
Spent Fuel Handling and Shipping
5 Standby Shutdown Facility Systems Operation
Steam Generator Secondary Side Operation
Turbine-Generator Operation
Unit Operation at Power
Unit Shutdown
Unit Startup

13.5.2.1.2 Emergency Procedures

Emergency procedures are written which specify steps to be taken during foreseeable emergency situations. These procedures are based on a sequence of observations and actions, with emphasis placed on operator responses to indications in the Control Room. When immediate operator actions are required to prevent or mitigate the consequences of an emergency situation, procedures require that those actions be implemented at the earliest possible time, even if full knowledge of the emergency situation is not yet available.

The actions outlined in emergency procedures are based on a conservative course of action to be followed by the operating crew. Written procedures, however, cannot address all contingencies, and emergency procedures, therefore, contain a degree of flexibility consistent with the fact that an emergency situation may not follow an anticipated sequence.

Typical situations addressed by emergency procedures are:

Abnormal Release of Radioactivity
Acts of Nature (Earthquake, Flood, Tornado, etc.)
Inoperable Control Element Assemblies
Loss of Component Cooling
Loss of Containment Integrity
Loss of Control Room
Loss of Electrical Power
1 Loss of Feedwater
Loss of Instrument Air
Loss of Reactor Coolant
Loss of Reactor Coolant Flow
Loss of Residual Heat Removal
6
Reactor Trip
Spent Fuel Damage
Steam Generator Tube Failure
Steam Supply System Rupture
Turbine-Generator Trip
6 Loss of Low Pressure Injection System

6 Loose parts in Reactor Coolant System
6 High Activity in Reactor Coolant System

Duke Power Company has also in place a program for preparing and implementing emergency operating procedures. This program was developed in response to NUREG-0737 Item I.C.1, "Guidance for the Evaluation and Development of Procedures for Transients and Accidents." Duke Power Company's program for developing emergency operating procedures for Oconee Units 1, 2, and 3 has been reviewed and approved by NRC. (Letter from John F. Stolz (NRC) to Hal B. Tucker (Duke) date June 7, 1985. Subject: Safety Evaluation Report on "Procedures Generation Package").

13.5.2.1.3 Temporary Operating Procedures

Temporary operating procedures are approved written procedures issued for operating activities which are of a nonrecurring nature. Examples of such uses are: (a) to direct operating activities during special testing or maintenance; (b) to provide guidance in unusual situations not within the scope of normal procedures; and (c) to assure orderly and uniform operations for short periods of time when the station, a unit, a structure, a system, or, a component is performing in a manner not addressed by existing procedures, or has been modified or extended in such a manner that portions of existing procedures do not apply.

The format of these procedures includes a purpose, limits and precautions, initial conditions, and step-by-step instructions for each mode of operation and necessary enclosures.

Temporary operating procedures are sufficiently detailed that qualified individuals can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

13.5.2.1.4 Annunciator Response Procedures

Annunciator response procedures are written which specify operator actions necessary to respond to an off-normal condition as indicated by an alarm. The format for annunciator response procedures includes alarm setpoints, probable causes, automatic actions, immediate manual actions, supplementary actions, and applicable references.

In order to insure that annunciator response procedures are readily accessible for reference, a positive method is employed to allow their retrieval. Each annunciator panel is designated by a unique and obvious nameplate. All of the annunciator windows within a panel are designated by identifying names. The annunicator response procedures are grouped by panels, then subdivided by annunciator names so that the response procedure for any annunciator may be quickly located.

13.5.2.2 Other Procedures

13.5.2.2.1 Maintenance Procedures

Maintenance of station safety-related structures, systems, and components is performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances (for example, skills normally possessed by qualified maintenance personnel may not require detailed step-by-step delineation in a written procedure) which conform to applicable codes, standards, specifications, criteria, etc. Where appropriate sections of related vendor manuals, instructions, or approved drawings with acceptable tolerances do not provide adequate guidance to assure the required quality of work, an approved, written maintenance procedure is provided.

Maintenance procedures are sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore, contain a degree of flexibility appropriate to the activities for which each is applicable.

5 The Maintenance Superintendent has responsibility for preparation and implementation of maintenance procedures.

The administrative control of maintenance is maintained as follows:

1. In order to assure safe, reliable, and efficient operation, a comprehensive maintenance program for the station's safety-related structures, systems, and components is established.
5 2. The Maintenance Superintendent is responsible for directing the performance of station maintenance
5 activities affecting instrumentation and electrical and mechanical equipment.
3. Personnel performing maintenance activities are qualified in accordance with applicable codes and standards, as appropriate.
4. Maintenance is performed in accordance with written procedures which conform to applicable codes, standards, specifications, criteria, etc.
5. Maintenance is scheduled so as not to jeopardize station operation or the safety of a reactor or reactors.
6. Maintenance histories are maintained on station safety-related structures, systems, and components.

1 The administrative control of modifications is discussed in "Quality Assurance Program," Topical Report, DUKE-1A.

13.5.2.2.2 Instrument Procedures

Maintenance, testing, and calibration of station safety-related instruments is performed in accordance with written, approved procedures.

Instrument procedures are sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

5 The Maintenance Superintendent has responsibility for preparation and implementation of instrument procedures.

13.5.2.2.3 Periodic Test Procedures

Testing conducted on a periodic basis to determine various station parameters and to verify the continuing capability of safety-related structures, systems, and components to meet performance requirements is conducted in accordance with approval, written procedures. Periodic test procedures are utilized to perform such testing, and are sufficiently detailed that qualified personnel can perform the required functions without direct supervision.

5 Periodic test procedures are performed by the station's Engineering, Operations, and Maintenance groups.

13.5.2.2.4 Chemistry Procedures

Chemical and radiochemical activities associated with station safety-related structures, systems, and components are performed in accordance with approved, written procedures and the station chemistry manual.

Each procedure is sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

1 The Chemistry Manager has responsibility for preparation and implementation of chemistry procedures.

13.5.2.2.5 Radioactive Waste Management Procedures

Radioactive waste management activities associated with the station's liquid, gaseous, and solid waste systems are performed in accordance with approved, written procedures.

Each procedure is sufficiently detailed that qualified workers can perform the required functions without direct supervision. Written procedures, however, cannot address all contingencies, and therefore contain a degree of flexibility appropriate to the activities for which each is applicable.

The station's Operations group, Chemistry, and Radiation Protection sections have responsibility for preparation and implementation of the radioactive waste management procedures.

13.5.2.2.6 Radiation Protection Procedures

Information concerning these procedures is presented in Chapter 12, "Radiation Protection."

13.5.2.2.7 Plant Security Procedures

Station Security Procedures shall be developed to implement the scope of Safeguard Activities required by the safeguard plans addressed in Section 13.6, "Nuclear Security" of the FSAR.

13.5.2.2.8 Emergency Preparedness Procedures

2 Information concerning these procedures is presented in the Oconee Nuclear Site Emergency Plan which
2 is discussed in topic 13.3, "Emergency Planning."

13.5.2.2.9 Material Control Procedures

Information concerning these procedures is presented in the Duke Power Company Topical Report,
1 Quality Assurance Program, DUKE-1A.

13.5.2.2.10 Modification Procedures

Information concerning these procedures is presented in the Duke Power Company Topical Report,
1 Quality Assurance Program, DUKE-1A.

13.5.2.2.11 Fire Protection Procedures

Information concerning these procedures is presented in Section 13.5.1.3.11, "Fire Protection Procedures."

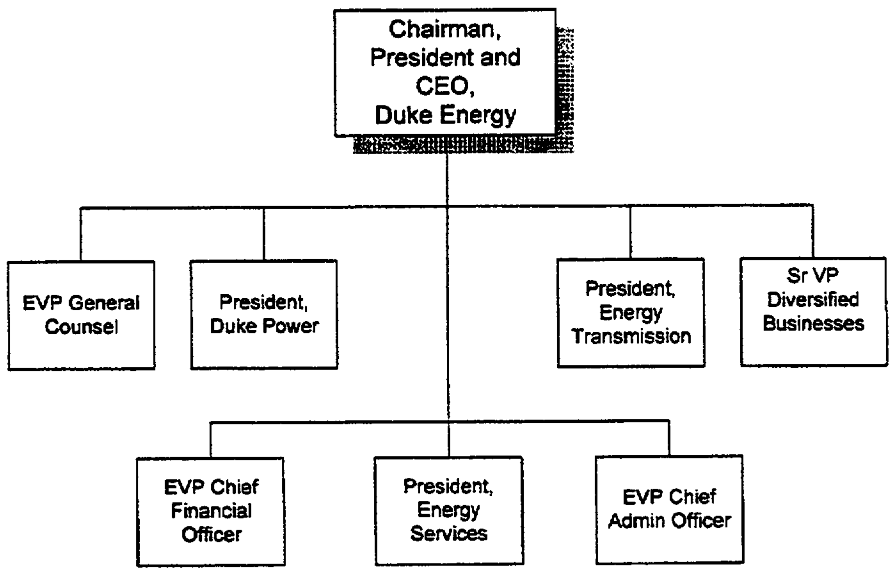
2 13.6 NUCLEAR SECURITY

The Station Physical Security Plan, Safeguards Contingency Plan and the Training and Qualification Plan (T&Q Plan) were submitted and NRC accepted for the protection of Oconee nuclear station against potential acts of radiological sabotage. This information is to be withheld from public disclosure pursuant to 10CFR 2.790(d) and 10CFR 73.21. The general scope of Safeguard Activities encompassed by the
2 Safeguard Plans include: (1) the physical security organization; (2) selection and training of personnel for
2 security purposes; (3) communications systems for controls to the plant including physical barriers and
2 means of detecting unauthorized intrusions; and (4) arrangements with law enforcement authorities for
2 assistance in responding to any security threat.

9 The Safeguard Plans conform to the requirements of 10CFR 50.34 (c) and (d) and 10CFR 73.55 except
9 for (d)(5), which was exempted by the NRC April 9, 1997.

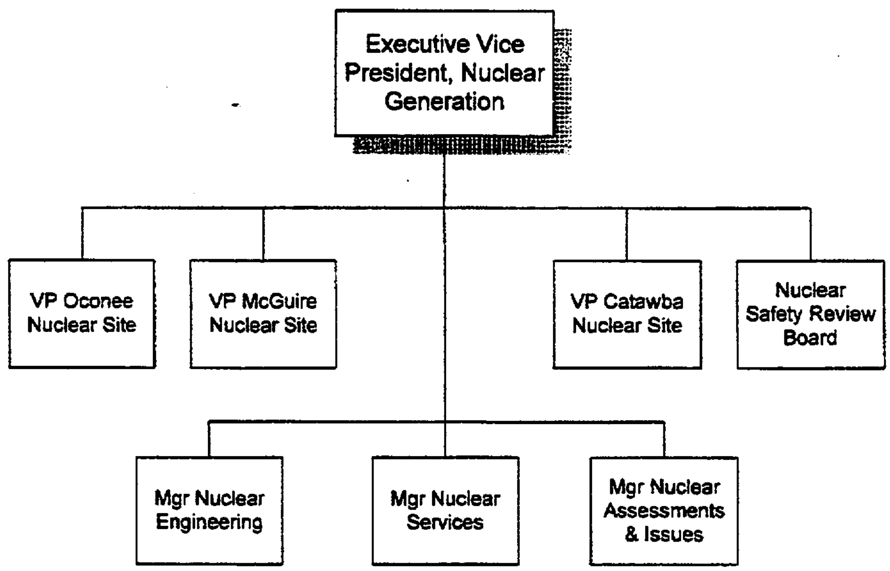
5 A vehicle barrier system (VBS) was installed at Oconee in accordance with NRC guidance provided in
5 NUREG/CR-6190 and 10CFR73.55 (Reference NSM-52973). The VBS prevents vehicle intrusion and is
5 required to comply with 10CFR73.55(c)(7)(8)(9)&(10). The vehicle barrier system is not nuclear safety
5 related.

THIS IS THE LAST PAGE OF THE CHAPTER 13 TEXT PORTION.

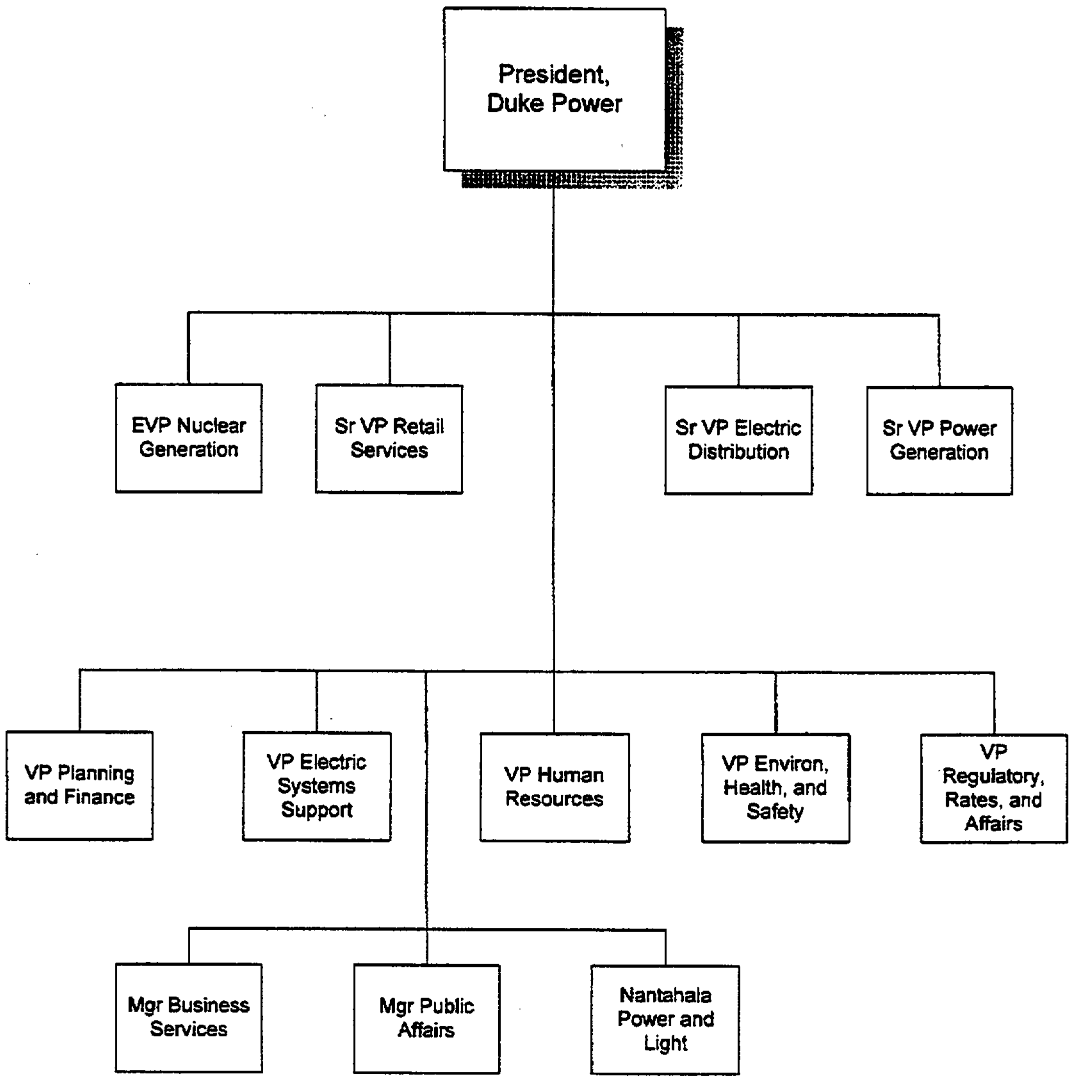


9 **Figure 13-1.**
9 **Duke Energy Corporation Structure**

9 **Figure 13-2.**
9 **Deleted Per 1999 Update**



9 Figure 13-3.
9 Nuclear Generation Department



9 Figure 13-7.
9 Duke Power Company Structure

TABLE OF CONTENTS

LIST OF TABLES

CHAPTER 14. INITIAL TESTS AND OPERATION

A comprehensive initial testing and operating program was conducted at the Oconee Nuclear Station. The purpose of this program was (1) to assure that the equipment and systems perform in accordance with design criteria, (2) to effect initial fuel loading in a safe efficient manner, (3) to determine the nuclear parameters, and (4) to bring the unit to rated capacity.

The test program began as installation of individual components and systems was completed. The individual components and systems were tested and evaluated according to written test procedures. An analysis of the test results verified that each component and system performed satisfactorily.

The written procedures for the initial tests and operation included the purpose, conditions, precautions, limitations, prerequisites, and the acceptance criteria.

14.1 ORGANIZATION OF TEST PROGRAM

14.1.1 GENERAL ORGANIZATION

The organization for development and execution of the test program had major participants from the Oconee Nuclear Station operating personnel, the Nuclear Production Department General Office staff, and Babcock & Wilcox (B&W) Site Operations. Additional participants were from the Duke Engineering Department; Construction Department; and Electrical, Maintenance, and Construction Department. Bechtel Corporation participated in the tests associated with the Reactor Building.

The Oconee Nuclear Station organization for the test program consisted of the Superintendent, Assistant Superintendent, Station Review Committee (SRC), and a station test coordinator assigned for each test.

The Nuclear Production Department General Office staff organization for the test program consisted of a Nuclear Production General Office test coordinator assigned for each test.

The B&W Site Operations organization for the test program consisted of the Site Operations Manager, Site Operations Engineer, and Site Service Engineers who worked in the specific areas of test procedures, testing, startup, operations, maintenance, fueling, field analysis, and reports. The test program had technical support from B&W Nuclear Power Generation Division engineers. This support included technical analysis of the test results of certain tests with the result analyses transmitted to the Nuclear Production Department through normal channels of communication for checking and final analyses prior to test completed approval. Special rapid channels of communication were utilized where results were needed as soon as possible for other operations to proceed. The qualifications for the B&W Site Operations organization are listed below:

1. The minimum qualification for the B&W Site Operations Manager are:
    a. Graduate in engineering, or related physical science, or equivalent experience. (2 years experience for one year of college).
    b. Four years of responsible power plant experience or two years of responsible nuclear reactor experience.
    c. One year engineering or test program preparation experience for this or similar nuclear plant.
2. The minimum qualifications for the B&W Site Operations Engineer are:
    a. Graduate in engineering, or related physical science or equivalent experience. (2 years experience for one year of college).
    b. Two years of responsible power plant experience or one year of responsible nuclear reactor experience.
    c. One year engineering or test program preparation experience for this or similar nuclear plant.

Various individuals from the Mechanical, Electrical, and Civil sections of the Duke Engineering Department furnished technical support as needed in specific areas. Similarly, individuals in the Duke Construction Department, Duke Electrical, Maintenance, and Construction Department; and Bechtel Corporation furnished technical support as needed. This support principally applied to the review of test procedures prior to approval, analysis of test results, and the development and installation of modifications to the equipment and systems as required and identified during the test program. Qualifications for Duke personnel are contained in Chapter 13, "Conduct of Operations."

During the initial criticality (including fuel loading) and post-criticality phases of the test program, the nuclear physics and thermal hydraulics aspects of the reactor operation were under the technical responsibility of the Nuclear Production Department Nuclear Engineer and the Oconee Technical Support Engineer with assistance from B&W Site Operations, B&W Nuclear Power Generation Division, and Duke Engineering Department nuclear engineers as needed. A very close coordination between these groups existed with the appropriate support available when needed.

14.1.2 RESPONSIBILITIES

14.1.2.1 Superintendent

The Superintendent or his authorized representative has final responsibility for the overall test program which included the approval of the test procedures, modification of test procedures, scheduling, completion of the tests, and approval of the test results. Approval of test procedures, modifications of test procedures, and approval of test results was not be made without giving proper consideration to recommendations of Babcock and Bechtel in their areas of interest.

14.1.2.2 Test Working Group

A Test Working Group (TWG) coordinated the activities of B&W, Duke Construction, and Nuclear Production Department during the preoperational test program. Representatives were from Oconee Nuclear Station and B&W (Site Operations Engineer). Duke Engineering; Construction; Steam Production General Office; and Electrical, Maintenance, and Construction Departments had representatives participate as required. The Oconee representative was chairman of the TWG. The TWG met at regular intervals; approximately every week during the most active phases of the program.

14.1.2.3 Station Test Coordinator

A station test coordinator was designated for each test. His responsibility was to develop the test procedure, coordinate the performance of the test, analyze results, identify discrepancies in test and acceptance criteria, initiate action to correct discrepancies, obtain approval of other parties when test had been completed satisfactorily, and file results in the master final documentation file.

14.1.2.4 Nuclear Test Engineer

A general office nuclear test engineer was designated for the testing program. His responsibility was to furnish technical guidance for the test program; to assist in the development of the approved procedures; and to assist the station personnel in conducting and evaluating the tests. Other members of the general office staff assisted in the test program as necessary.

14.1.2.5 Nuclear Safety Review Committee

An audit of safety related tests and their results was performed by the Nuclear Safety Review Committee.

14.1.3 RESOLUTION OF DISCREPANCIES

Any discrepancies in systems or equipment found during the Test Program was promptly reported by the station test coordinator to the Superintendent. A corrective action request was made to the appropriate departments by the Superintendent to initiate any revision or repair deemed necessary. After the corrective action had been completed the Superintendent or his authorized representative was notified.

Retests were performed on systems and components as necessary to verify the adequacy of the corrective action.

Prior to any revisions relating to the health and safety of the public or plant personnel, structural integrity of plant components and systems, and items covered by codes and nuclear standards, review and approval was necessary by the Duke Power Design Engineering Department with assistance from vendors or consultants as necessary.

14.2 TESTS PRIOR TO REACTOR FUEL LOADING

The tests prior to reactor fuel loading assure that systems are complete and operate in accordance with design. The test program was divided into two phases: Preheatup Test Phase and Hot Functional Test Phase. In many instances systems were tested during both the Preheatup Test Phase and the Hot Functional Test Phase. A list of the tests performed prior to fuel loading is provided in Table 14-1. This section summarizes the initial test program prior to fuel loading for Oconee 1, 2, and 3. The startup reports and supplements, References 1 through 14, provide the results of the startup test program for each unit.

The types of tests are classified as hydro/leak, operational, electrical, and functional with the following definitions for each classification:

Hydro/Leak Test	–	Structural integrity leak test of the various systems and components at the appropriate pressure.
Operational Test	–	Operation of systems and equipment under operating conditions.
Electrical Test	–	Consists of: grounding, megger, continuity, and phasing checks; circuit breaker operation and control checks; potential measurement and energizing of buses and equipment to ensure continuity, circuit integrity, and proper functioning of electrical apparatus.
Functional Test	–	Tests to verify that systems and equipment will function as intended.

Instruments and controls of each system or component were also subjected to a preoperational instrumentation and controls calibration prior to the initial operation of that system or component to assure proper operation.

An Engineered Safeguard Actuation System test was performed to assure actuation and proper operation of the Engineered Safeguards System and to evaluate the test method and frequency for future testing.

6 A one-time emergency power ES functional test which involves the three Oconee units during shutdown
6 conditions has been evaluated. The scope of the test was described in Duke letters to the NRC dated
6 November 21, 1996, and December 11, 1996. This test verified certain design features of the emergency
6 power system in an integrated fashion. Oconee Unit 3 was defueled and Oconee Units 1 and 2 were at
6 cold shutdown with fuel in the reactor core during the performance of the test.

8 A one time Keowee Emergency Power - Engineering Safeguards Functional Test which involves Oconee
8 Unit 3 during 3EOC17 has been evaluated. This test verifies certain design features of the emergency
8 power and engineering safeguards systems in an integrated fashion. The scope of the test supports Nuclear
8 Station Modification (NSM) ON-53014. This integrated test will emergency start the Keowee Unit aligned
8 to the underground power path from shutdown condition and accept loads from the shutdown Oconee
8 Unit through the standby bus.

14.2.1 PREHEATUP TEST PHASE

The objective of the Preheatup Test Phase was to assure that the equipment and systems perform as required for hot functional testing. This phase of the testing included certain preoperational calibration, hydro/leak, operational, electrical, and functional tests as required. The Reactor Building Containment

System has undergone a structural integrity and integrated leakage rate test to verify the building design and to ensure that leakage is within the design limit.

14.2.2 HOT FUNCTIONAL TEST PHASE

The Hot Functional Test Phase was a period of hot operation of the Reactor Coolant System and the associated auxiliary systems prior to the initial fueling of the reactor. The Reactor Coolant System was heated up to no-load operating pressure and temperature.

The Hot Functional Test Phase continued the preparation toward the initial fuel loading. The objectives of this phase of the test program were:

1. Operational test of systems, components, and non-nuclear instrumentation and controls at no load operating pressure and temperature.
2. Operator training.
3. Verification of normal operating procedures.
4. Verification of emergency operating procedures.

Following the hot functional test, the reactor vessel intervals were removed and inspected for signs of distress, e.g., loose parts, cracking, or fretting.

14.3 INITIAL CRITICALITY TEST PROGRAM

The Initial Criticality Test Program consists of the initial fuel loading followed by initial criticality.

14.3.1 INITIAL FUEL LOADING

Fuel was loaded into the reactor in accordance with a step-by-step written procedure. This procedure contains a number of safety precautions and operating limitations.

The fuel loading procedure includes:

1. A sequence of loading temporary detectors, sources, control rods, and fuel assemblies in order to maintain shutdown margin requirements.
2. The conditions under which fuel loading may continue after any step.
3. An identification of responsibility and authority.
4. During any reactivity changes, a minimum of two detectors will be operating and indicating neutron level after the source has been inserted. At all other times, at least one detector shall be indicating neutron level.
5. Two completely independent plots of reciprocal neutron multiplications as a function of the parameter causing reactivity change are maintained.
6. Reactivity effects for each fuel assembly addition are checked prior to the release of the fuel assembly by the fuel handling grapple.
7. An estimate of the reactivity effect for the next fuel addition is made prior to insertion of the next fuel assembly.
8. The boron concentration in the reactor vessel, spent fuel pool, and Reactor Coolant System is maintained at a value to assure the required subcritical margin at all times.
9. The valve alignment of the auxiliary systems connected to the Reactor Coolant System is checked periodically to prevent dilution of the reactor coolant boron concentration.
10. Chemical analysis and water level monitoring is used to assure that inadvertent dilution of the reactor coolant boron concentration has not occurred.
11. Communication between control room and fuel handling areas is maintained.
12. The Plant Radiation Monitoring Systems are in operation.
13. Radiation Protection and chemistry monitoring and services are provided.

14.3.2 PREPARATION FOR INITIAL CRITICALITY

Upon completion of the initial fuel loading, prestartup checks were completed prior to the approach to initial criticalty. The prestartup checks included:

1. Control rod trip test
2. Reactor coolant flow test
3. Reactor coolant flow coastdown test

A reactor coolant flow test and a reactor coolant flow coastdown test were conducted under cold reactor conditions to assure that the flow characteristics of the Reactor Coolant System had not materially changed as a result of the reactor core installation.

14.3.3 INITIAL CRITICALITY

A written procedure was followed during the approach to initial criticality. This procedure specified in detail the sequence to be followed, the limitations and precautions, the required plant status, and the prerequisite system conditions. (This procedure also specified the alignment of fluid systems to assure controlled boron dilution and core conditions under which the approach to criticality proceeded.)

Permissible rod group withdrawal and deboration are based on calculated reactivity effects. Two independent plots of inverse multiplication characteristics are maintained during rod group withdrawal and deboration. A predicted rod group position or boron concentration for criticality is determined before the next rod group withdrawal or deboration is started.

14.4 POSTCRITICALITY TEST PROGRAM

2 The Postcriticality Test Program was performed to provide assurance that the plant is operating in a safe
and efficient manner. Systems and components which cannot be operationally tested prior to initial
2 criticality were tested during the Postcriticality Test Program to verify reactor parameters and to obtain
information required for plant operation. A list of the postcriticality tests is provided in Table 14-2. This
2 section summarizes the test program after each unit achieved initial criticality. The startup reports and
supplements, References 1 through 14, provide the results of the startup test program for each unit.

14.4.1 ZERO POWER PHYSICS TESTS

2 Following initial criticality, a program of reactor physics measurements was undertaken to verify the
2 physics parameters. Measurements were made under zero power condition at sufficient temperature
plateaus to verify calculated worths of individual control rods and control rod groups, moderator
temperature coefficient, boron worth, and excess reactivity of the core. In addition, the response of the
2 source and intermediate range nuclear instrumentation were verified.

Detailed written procedures specifying the sequence of tests, parameters to be measured, and conditions under which each test is to be performed were followed. These tests involve a series of prescribed control rod configurations and boron concentrations with intervening measurements of control rod and/or boron worth during boron dilution or boron injection.

14.4.2 POWER ESCALATION TEST PROGRAM

Following determination of the operating characteristics and physics parameters of the reactor at zero power, a detailed power escalation test program was conducted. This program consists of specified incremental increases in power levels up to full power with appropriate testing conducted at each power level. An analysis of the significant parameters at each step was made prior to initiating an additional power escalation.

At selected power levels, the following tests were performed:

1. Unit heat balance test
2. Power coefficient measurement
3. Core power distribution measurement
4. Unit load steady state test
5. Unit transient test.

Other Power Escalation Tests were performed at one or more power levels in the test sequence.

14.5 STARTUP PHYSICS TEST PROGRAM

3

14.6 OPERATING RESTRICTIONS

During initial operations and associated testing, the normal plant safety procedures and technical specifications are in effect. In addition, special safety precautions and limitations are included in the test procedures and more restrictive operating limitations than those in the technical specifications are imposed, where required, from initial criticality through the power escalation program. The Reactor Protective System power level trip point was initially set at a low value and raised as the power escalation program progresses.

14.6.1 REFERENCES

1. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), November 16, 1973, Oconee 1 Startup Report.
2. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), February 14, 1974, Oconee 1 Startup Report - Supplement 1.
3. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), May 15, 1974, Oconee 1 Startup Report - Supplement 2.
4. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), August 12, 1974, Oconee 1 Startup Report - Supplement 3.
5. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), November 11, 1974, Oconee 1 Startup Report - Supplement 4.
6. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), February 7, 1975, Oconee 1 Startup Report - Supplement 5.
7. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), May 8, 1975, Oconee 1 Startup Report - Supplement 6.
8. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), August 9, 1974, Oconee 2 Startup Report.
9. Thies, A. C. (DPC), Letter to Giambusso, A. (NRC), November 7, 1974, Oconee 2 Startup Report - Supplement 1.
10. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), February 5, 1975, Oconee 2 Startup Report - Supplement 2.
11. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), May 6, 1975, Oconee 2 Startup Report - Supplement 3.

9 12. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), March 14, 1975 Oconee 3 Startup Report.

13. Thies, A. C. (DPC), Letter to Moseley, N. C. (NRC), June 12, 1975, Oconee 3 Startup Report - Supplement 1.
14. Parker, W. O. Jr. (DPC), Letter to Moseley, N.C. (NRC), August 25, 1975, Oconee 3 Startup Report - Supplement 2.
15. Parker, W. O. Jr. (DPC), Letter to Denton, H. R. (NRC), August 15, 1980.
16. Parker, W. O. Jr. (DPC), Letter to Denton, H. R. (NRC), August 15, 1980.
17. Stolz, J. F. (NRC), Letter to Parker, W. O. Jr (DPC), March 23, 1981.
18. Thies, A. C. (DPC), Letter to Denton, H. R. (NRC), May 29, 1981.
19. Wagner, P. C. (NRC), Letter to Parker, W. O. Jr. (DPC), November 30, 1981.
20. Tucker, H. B. (DPC), Letter to Denton, H. R. (NRC), September 2, 1986.
21. Stolz, J. F. (NRC), Letter to Tucker, H. B. (DPC), October 7, 1986.

THIS IS THE LAST PAGE OF THE CHAPTER 14 TEXT PORTION.