TABLE OF CONTENTS

CHAPTER 7.0

INSTRUMENTATION AND CONTROLS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES

LIST OF TABLES (Continued)

LIST OF FIGURES

LIST OF FIGURES (Continued)

LIST OF FIGURES (Continued)

CHAPTER 7.0

INSTRUMENTATION AND CONTROLS

7.1 INTRODUCTION

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

The instrumentation and control systems provide automatic protection and exercise proper control against unsafe and improper reactor operation during steady state and transient power operations (Conditions I and II) and to provide initiating signals to mitigate the consequences of emergency and faulted conditions (Conditions III and IV). ANS conditions are discussed in Chapter 15.0.

Applicable criteria and codes are listed in Table 7.1-2.

7.1.1 IDENTIFICATION OF SAFETY-RELATED SYSTEMS

Safety-related instrumentation and control systems and their supporting systems are those systems required to ensure:

a. The integrity of the reactor coolant pressure boundary.

b. The capability to shut down the reactor and maintain it in a safe shutdown condition.

c. The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposures of 10 CFR 100.

The definitions provided below are used to classify the instrumentation systems into the categories defined for Chapter 7.0 by Regulatory Guide 1.70.

A listing of these systems, by categories, that are comparable to those of nuclear power plants of similar design is given in Table 7.1-1. Table 7.1-1 also identifies the systems that are different with references to discussions of those differences.

The plant's control and instrumentation systems are grouped into the following categories:

a. Reactor trip system (RTS)

b. Engineered safety feature actuation systems (ESFAS)

c. Systems required for safe shutdown

d. Safety-related display instrumentation

e. Other instrumentation systems required for safety

f. Systems not required for safety

Descriptions of the above are given in Sections 7.1.1.1 through 7.1.1.6. Table 7.1-2 identifies which instrumentation systems are safety related.

7.1.1.1 Reactor Trip System

The RTS is described in Section 7.2. Figure 7.1-1 is a single-line diagram of this system.

7.1.1.2 Engineered Safety Feature Actuation Systems

The ESFAS are those instrumentation systems which are needed to actuate the equipment and systems required to mitigate the consequences of postulated design basis accidents. The engineered safety features requiring actuation are:

a. Main steam and feedwater isolation (Sections 6.2.4 and 7.3.7)

b. Containment combustible gas control (Sections 6.2.5 and 7.3.1)

c. Containment purge isolation (Sections 6.2.4 and 7.3.2)

d. Fuel building ventilation isolation (Sections 7.3.3 and 9.4.2)

e. Control room ventilation isolation (Sections 7.3.4 and 9.4.1)

f. Auxiliary feedwater supply (Sections 7.3.6 and 10.4.9)

g. Nuclear steam system supply (NSSS) ESFAS (Section 7.3.8)

The equipment which provides the engineered safety feature actuation functions for the systems listed above is identified and discussed in Section 7.3. Design bases for these engineered safety feature actuation systems are also given in Section 7.3. For auxiliary supporting systems, see Section 7.3.8.1.11 and Table 7.3-12.

7.1.1.3 Systems Required for Safe Shutdown

Systems required for safe shutdown are defined as those essential for pressure and reactivity control, coolant inventory makeup, and removal of residual heat once the

reactor has been brought to a subcritical condition. These functions are categorized according to the shutdown modes defined in Table 1.1-1 of the Callaway Technical Specifications.

Identification of the equipment and systems required for safe shutdown is provided in Section 7.4. Additional information regarding hot standby provisions for shutdown from outside the control room is also provided in Section 7.4.

7.1.1.4 Safety-Related Display Instrumentation

Safety-related display instrumentation is instrumentation which provides information for the operator to manually perform reactor trip, engineered safety feature actuation, post-accident monitoring or safe shutdown functions.

Identification of the equipment and systems in safety-related display instrumentation is provided in Section 7.5. Description of other indicating systems which provide information for monitoring equipment and processes is also provided in Section 7.5.

Section 7.5 and Table 7.5-1 summarize procedures required to maintain the plant in a hot standby condition, or to proceed to cold shutdown.

7.1.1.5 All Other Instrumentation Systems Required for Safety

The other instrumentation systems required for safety - other than the RTS, the ESFAS, safety-related display and the safe shutdown systems - are discussed in Section 7.6. They are those systems and components which have a preventive role in reducing the effects of accidents. Single failures in these systems will not inhibit reactor trip, engineered safety feature actuation, or functions required for safe shutdown. The other instrumentation systems required for safety consist of the following:

a. Instrumentation and control power supply system

b. Residual heat removal system isolation valve interlocks

c. Refueling interlocks

d. Accumulator motor-operated isolation valve interlocks

e. Emergency core cooling system switchover from injection mode to recirculation mode

f. Interlocks for RCS pressure control during low temperature operation

g. Isolation of nonseismic Category I piping from seismic Category I cooling systems

h. Interlocks for pressurizer pressure relief system

i. Switchover of charging pump suction to refueling water storage tank (RWST) on low-low volume control tank level

j. Instrumentation for mitigating consequences of inadvertent boron dilution

k. Charging pump miniflow interlock

l. Neutron flux monitoring

Item a above is described in Section 8.3.1.1.5. Item c is described in Section 9.1.4. The remaining items are described in Section 7.6.

7.1.1.6 Control Systems Not Required for Safety

Control systems not required for safety are those automatic and manual systems designed for the primary purpose of normal load control, startup, and shutdown of the main power generating system. As shown in Section 7.7, malfunctions in these systems will not result in unsafe conditions.

7.1.2 IDENTIFICATION OF SAFETY CRITERIA

Considerations for instrument errors are included in the accident analyses presented in Chapter 15.0. Functional requirements, developed on the basis of the results of the accident analyses, that have utilized conservative assumptions and parameters are used in designing these systems. A preoperational testing program verifies the adequacy of the design. Accuracies are given in Sections 7.2, 7.3, and 7.5.

The criteria listed in Table 7.1-2 were considered in the design of the systems given in Section 7.1.1. A discussion of compliance with each criterion for systems in its scope is provided in the referenced sections given in Table 7.1-2. Because some criteria were established after design and testing had been completed, the equipment documentation may not meet the format requirements of some standards. Justification for any exceptions taken to each document for systems in its scope is provided in the referenced sections.

7.1.2.1 Design Bases

The design bases for the safety-related systems are provided in the respective sections of Chapter 7.0.

7.1.2.2 Independence of Redundant Safety-Related Systems

The safety-related systems are designed to meet the independence and separation requirements of GDC-22 and Section 4.6 of IEEE Standard 279-1971.

The electrical power supply, instrumentation, and control conductors for redundant circuits at the Callaway Plant have physical separation to preserve the redundancy and to ensure that no single credible event will prevent operation of the associated function. Critical circuits and functions include power, control, and analog instrumentation associated with the operation of the safety-related systems. Events considered credible and considered in the design include the effects of short circuits, pipe rupture, missiles, fire, and earthquake.

7.1.2.2.1 General

The physical separation criteria for redundant safety-related system sensors, sensing lines, wireways, cables, and components on racks meet the recommendations contained in Regulatory Guide 1.75 with the following comments:

a. The protection systems use redundant instrumentation channels and actuation trains and incorporate physical and electrical separation to prevent faults in one channel from degrading any other protection channel.

b. Where no redundant circuits share a single compartment of a safety-related instrumentation rack and these redundant safety-related instrumentation racks are physically separated, the recommendations of Position C.16 of Regulatory Guide 1.75 do not apply.

c. Redundant, isolated control signal cables leaving the protection racks are brought into close proximity elsewhere in the plant, such as the control board. It could be postulated that electrical faults, or interference, at these locations might be propagated into all redundant racks and degrade protection circuits because of the close proximity of protection and control wiring within each rack. Regulatory Guide 1.75 (Regulatory Position C.4) and IEEE Standard 384-1974 (Section 4.5(3)) provide the option to demonstrate by tests that the absence of physical separation could not significantly reduce the availability of Class 1E circuits.

   Westinghouse test programs have demonstrated that Class 1E protection systems (nuclear instrumentation system, solid state protection system, and 7300 process protection system) are not degraded by non-Class 1E circuits sharing the same enclosure. Conformance to the requirements of IEEE Standard 279-1971 and Regulatory Guide 1.75 has been established and accepted by the NRC, based on the following which is applicable to these systems at the Callaway Plant.

   Tests conducted on the as-built designs of the nuclear instrumentation system and solid state protection system were reported and accepted by the NRC in support of the Diablo Canyon application (Docket Nos. 50-275 and 50-323). Westinghouse considers these programs as applicable to all plants, including Callaway. Westinghouse tests on the 7300 process

protection system were covered in a report entitled, "7300 Series Process Control System Noise Tests," subsequently reissued as Reference 1. In a letter dated April 20, 1977 (Ref. 2), the NRC accepted the report in which the applicability to the Callaway Plant is established.

Replacement solid state protection system circuit boards were additionally analyzed and tested to ensure regulatory compliance was maintained as described in References 6, 7, and 8 for the three circuit boards associated with active safety functions.

The Westinghouse 7300 process protection system NCT (channel test) cards used in the four containment pressure High-3 channels for containment spray initiation also provide contacts to non-safety related annunciators to inform the operators when a channel is bypassed for test. These NCT cards have been analyzed to demonstrate that the non-safety annunciator circuits do not degrade the Class 1E circuits below an acceptable level.

The NCT card is a channel test card typically used in channels that interface only with the SSPS, and, therefore would not normally require isolation. However, for the containment spray circuits, which are energized to actuate, contacts from the NCT card to an annunciator were provided to indicate when a channel was bypassed for test. A qualified isolation device should be used to provide separation by preventing the propagation of electrical faults from non-safety systems. This separation is typically provided by NAI (annunciator interface) cards which have been proven by the testing documented in Reference 1 to be a qualified isolation device. The NCT cards have not been qualified by testing as isolation devices. The following analysis supports the use of the NCT cards without NAI cards, or other isolation devices, for this application.

The worst conceivable faults are generalized into three main categories. One category occurs in the annunciator input and associated circuitry including any short circuit faults. The second category occurs in the cable tray where the maximum possible voltage (120 VAC or 125 VDC) could be applied to the cable conductors and then directly to NCT card contacts. Lastly, a fault could occur where the contact degrades, increasing the power across the contact.

The maximum power seen by the NCT relay contact due to the contact resistance feeding the annunciator system was calculated to be one (1) watt, well below its ten (10) watt rating. The maximum induced voltage is considered to be of a low enough magnitude and short time duration to not degrade the safety-related circuits.

The first two categories of potential failures identified above would only occur if the relay contacts on the NCT card which feed the annunciator are closed. For these containment pressure High-3 channels, the contacts are closed only if the card is in test. During normal operation, the contacts are open. Therefore, any type of fault (up to impressing the rated contact voltage or voltage rating of the NCT circuit card traces) could occur and no fault current would flow through the NCT card circuit due to a non-1E circuit fault during normal operation.

Potential damage to the NCT card and its Class 1E circuit would only occur when the card was placed in test. Any damage would occur only in the channel which was placed in test. The other three channels would remain operable. Since the card that potentially fails would have already been authorized to be removed from service, the level of protection would not be reduced. Since the fault would be detected due to an annunciator malfunction when it occurs, the root cause of the failure would be determined and corrected prior to returning the channel to service. Troubleshooting would identify that potential NCT card degradation had occurred and the affected NCT card would either be replaced or determined to be undamaged and returned to service.

d. The physical separation criteria for instrument cabinets within the NSSS scope meet the recommendations contained in Section 5.7 of IEEE Standard 384-1974. Compliance with specific positions of Regulatory Guide 1.75 is given in Sections 8.1.4.3 and 8.3.1.4.

7.1.2.2.2 Specific Systems

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

There are four separate protection sets. Each protection set contains several channels, each channel sensing a different variable. Separation of redundant analog channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and process protection cabinets. Protection sets are formed at the process protection cabinets and transmit the required signals to the redundant trains in the solid state protection system logic racks (Figure 7.1-1). Redundant analog channels are separated by locating modules in different cabinets. Since all equipment within any cabinet is associated with a single protection set, there is no requirement for separation of wiring and components within the cabinet. See Section 7.1.2.3 for additional information.

In the nuclear instrumentation system and the solid state protection system cabinets where redundant channel instrumentation is physically adjacent, there are no wireways or cable penetrations which would permit a fire resulting from electrical failure in one channel to propagate into redundant channels.

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

a. Reactor trip system

   1. Separate routing is maintained for the four basic reactor trip system channel sets, analog sensor signals, bistable output signals, and power supplies for these systems. The separation of these four channel sets is maintained from sensors to instrument cabinets to logic system input cabinets.

   2. Separate routing of the redundant reactor trip signals from the redundant logic system cabinets is maintained, and, in addition, the cables carrying these signals are separated (by spatial separation or by provision of barriers or by separate cable trays or wireways) from the four analog channel sets.

b. Engineered safety feature actuation system

   1. Separate routing is maintained for the four basic sets of engineered safety feature actuation system analog sensing signals, bistable output signals, and power supplies for these systems. The separation of these four channel sets is maintained from sensors to instrument cabinets to logic system input cabinets.

   2. Separate routing of the engineered safety feature actuation signals from the redundant logic system cabinets is maintained. In addition, they are separated by spatial separation or by provisions of barriers or by separate cable trays or wireways from the four analog channel sets.

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

c. Instrumentation and control power supply system

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

Reactor trip system, engineered safety feature actuation system, and other safety-related system analog circuits may be routed in the same wireways provided the circuits have the same power supply and channel set identified (I, II, III, or IV).

7.1.2.2.3 Fire Protection

For electrical equipment, noncombustible or fire retardant material is specified.

Braided sheathed material used in the cables is noncombustible. For in-field wiring, cables in the power trays are sized using derating factors listed in IPCEA Publication P-46-426.

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

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

The electrical power supply, instrumentation, and control wiring for redundant circuits have physical separation to preserve redundancy and ensure that no single credible event will prevent operation of the associated function. Critical circuits include power, control, and analog instrumentation associated with the operation of the reactor trip system or engineered safety feature actuation systems. Credible events include the effects of short circuits, pipe rupture, pipe whip, high-pressure jets, missiles, fire, and earthquake. These events are considered in the basic plant design.

Physical space or barriers are provided between separation groups performing the same protective function.

In locations where a specific hazard exists (missile, jet, etc.) which could produce damage to safety-related controls and instrumentation required as an active functional part of a nuclear safety-related system, the physical separation, structural protection, or armor provided will be adequate to ensure that no multiple failures can result from a single event.

The minimum protection or spacing maintained between redundant safety-related control and instrumentation components will be:

a. In open space

   See the discussion of compliance with Regulatory Guide 1.75 (Appendix 3A).

b. Inside control panels or cabinets, except as noted in Section 7.1.2.2.1b, the minimum separation criteria are:

   1. Six inches of free space, or

   2. If a barrier is present, one inch plus the barrier. See also Section 8.3.1.4.1.2.

The criteria and bases for the independence of electrical cable, including routing, marking, and cable derating, are covered in Section 8.3. Fire detection and protection in the areas where wiring is installed is covered in Section 9.5.1.

7.1.2.3 Physical Identification of Safety-Related Equipment

All components required as part of the safety-related control and instrumentation systems are identified as safety-related components requiring formal quality assurance and supporting documentation. Specific requirements for each type of component are covered in its procurement specification. The quality assurance program is described in Chapter 17.0.

All panels and cabinets which contain one or more safety-related devices are subject to the requirements for safety-related systems.

Instrument racks and trays containing tubing or wiring connected to safety-related instrumentation devices are subject to the requirements for safety-related systems.

Safety-related systems and their component devices are identified as to their separation group. Each protection set described in Section 7.1.2.2.2 is included in its respective separation group.

There are four separation groups identifiable with process equipment associated with the RTS and ESFAS. A separation group may be comprised of more than a single process equipment cabinet. The color coding of each process equipment rack nameplate coincides with the color code established for the separation group of which it is a part. Redundant BOP channels are separated by locating them in different equipment cabinets. Separation of redundant channels begins at the process sensors and is maintained in the field wiring, containment penetrations, and equipment cabinets to the redundant trains in the logic racks. The NSSS solid state protection system input cabinets and the NSSS engineered safety feature actuation systems are divided into isolated compartments, each serving one of the redundant input channels. Horizontal 1/8-inch-thick solid steel barriers, coated with fire retardant paint, separate the compartments. One-eighth-inch-thick solid steel wireways coated with fire retardant paint enter the input cabinets vertically. The wireway for a particular compartment is open only into that compartment so that flame could not propagate to affect other channels. At the logic racks, the separation group color coding for redundant channels is clearly maintained until the channel loses its identity in the redundant logic trains. The

color coded nameplates described below provide identification of equipment associated with protective functions and their channel group association:

Protection Set I	Separation Group 1:	red with white lettering
Protection Set II	Separation Group 2:	white with black lettering
Protection Set III	Separation Group 3:	blue with white lettering
Protection Set IV	Separation Group 4:	yellow with black lettering
	Nonsafety-related:	black with white lettering

Within the control panels, where more than one separation group is present, wiring is identified by separation group or if the wiring is enclosed by conduit the separation group identification is located on the conduit.

Within a cabinet or panel associated and identified with a single safety-related separation group, no identification of the safety-related wiring is required. The separation group of the panel or cabinet, however, is clearly identified.

Within a panel or cabinet otherwise associated and identified with a single safety-related separation group, nonsafety-related wiring is clearly identified. However, provided such nonsafety-related wiring is maintained at a small quantity, identification of the safety-related wiring is not required.

All noncabinet-mounted protective equipment and components are provided with an identification tag or nameplate. Small electrical components, such as relays, have nameplates on the enclosure which houses them. All cables are numbered with identification tags. In congested areas, such as under or over the control boards, instrument racks, etc., cable trays and conduits containing redundant circuits shall be identified, using permanent markings. The purpose of such markings is to facilitate cable routing identification for future modifications or additions. Positive permanent identification of cables and/or conductors shall be made at all terminal points. There are also identification nameplates on the input panels of the solid state protection system.

7.1.2.4 Conformance to Criteria

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

7.1.2.5 Conformance to NRC Regulatory Guides

7.1.2.5.1 General

Conformance of BOP equipment to Regulatory Guides 1.22, 1.53, 1.62, 1.105, and 1.118 is addressed in Tables 7.1-3, 4, 5, 6, and 7, respectively.

Other regulatory guides pertinent to this section are: 1.7, 1.11, 1.21, 1.26, 1.29, 1.30, 1.40, 1.45, 1.47, 1.63, 1.68, 1.73, 1.75, 1.80, 1.89, 1.97, 1.100, 1.106, and 1.139. References to discussions of these regulatory guides are provided in Appendix 3A.

An additional discussion of the NSSS conformance to Regulatory Guide 1.22 and IEEE-338 and 379 is given in the following sections.

7.1.2.5.2 Conformance to Regulatory Guide 1.22

Periodic testing of the reactor trip and engineered safety feature actuation systems, as described in Sections 7.2.2 and 7.3, complies with Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions."

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

The actuation logic for the RTS and ESFAS is tested as described in Sections 7.2 and 7.3. As recommended by Regulatory Guide 1.22, where actuated equipment is not tested during reactor operation, it has been determined that:

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

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

c. The actuated equipment can be routinely tested when the reactor is shut down.

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

a. Manual actuation switches (RTS and ESFAS)

b. Main turbine trip system (actual trip)

c. Main steam isolation valves (actual full closure)

d. Main feedwater isolation valves (actual full closure)

e. Feedwater control valves (actual full closure)

f. Main feedwater pump trip solenoids

g. Reactor coolant pump seal water return valves (actual full closure)

h. Eight selected slave relays

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

a. Manual actuation switches for RTS and ESFAS

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

b. Main turbine trip system

Testing of the main turbine trip function under power operation is discussed in Section 10.2.3.6.

c. Closing the main steam isolation valves

See Table 7.1-3.

d. Closing the main feedwater isolation valves

See Table 7.1-3.

e. Closing the feedwater control valves

The actuation function for these valves and their associated solenoids are routinely tested during refueling outages. To close the valves at power would adversely affect the operation of the plant. The operability of the slave relays which actuate the solenoids is verified at power. The closing of these control valves is blocked when the slave relay is tested. It is noted that the solenoids work on the de-energize-to-actuate principle. The feedwater control valves will fail closed on the loss of electrical power to both of the solenoids.

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

f. Main feedwater pump trip solenoids

No credit is taken for the automatic tripping of the feedwater pumps, and, therefore, this function does not require periodic testing.

g. Reactor coolant pump seal water return valves

Seal water return line isolation valves are routinely tested during refueling outages. Closure of these valves during operation would cause the seal water system relief valve to lift, with the possibility of valve chatter. Valve chatter could damage this relief valve. Testing of these valves at power could cause equipment damage. Therefore, these valves will be tested during scheduled refueling outages. Thus, the guidelines of Regulatory Position D.4 of Regulatory Guide 1.22 are met.

h. Eight selected slave relays

Slave relays K602, K620 (turbine trip circuitry only; main feedwater pump trip solenoid circuitry is excluded as discussed in f above), K622, K624, K630, K740, K741, and K750 and their actuated equipment will be tested at least once per 18 months during refueling and during each cold shutdown exceeding 24 hours unless they have been tested within the previous 92 days. Justification for the extended test interval is based on plant operational concerns and was presented in detail in References 3 and 5.

7.1.2.6 <u>Conformance to IEEE Standards</u>

7.1.2.6.1 Conformance to IEEE Standard 379-1972

The principles described in IEEE Standard 379-1972 were used in the design of the solid state protection system. The system complies with the intent of this standard and the additional guidance of Regulatory Guide 1.53, although the formal analyses have not been documented exactly as outlined. Westinghouse has gone beyond the required analyses and has performed a fault tree analysis (Ref. 4).

The referenced report provides details of the analyses of the solid state protection system previously made to show conformance with the single failure criterion set forth in Section 4.2 of IEEE Standard 279-1971. The interpretation of the single failure criterion provided by IEEE Standard 379-1972 is not substantially different than the Westinghouse interpretation of the criterion, except in the methods used to confirm design reliability. Replacement solid state protection system circuit boards were additionally analyzed and

tested to ensure regulatory compliance was maintained as described in References 6, 7, and 8 for the three circuit boards associated with active safety functions.

The RTS and ESFAS safety-related systems featuring redundant design provisions. The required periodic testing of these systems will disclose any failures or loss of redundancy which could have occurred in the interval between tests, thus ensuring the availability of these systems.

7.1.2.6.2 Conformance to IEEE Standard 338-1971

The periodic testing of the RTS and ESFAS conforms to the requirements of IEEE Standard 338-1971 with the following comments:

a. The surveillance requirements in the Callaway Technical Specifications for the solid state protection system ensure that the system functional operability is maintained comparable to the original design standards.

   Periodic tests at the established intervals demonstrate this capability for the system.

b. Callaway's administrative program for the response time testing of the RTS and ESFAS instrumentation meets the requirements of section 6.3.4 of IEEE Standard 338-1977, as clarified below:

   For sensors, Callaway performs periodic response time testing or makes use of allocated response times. The methods of testing, when required, fall into two categories as follows:

   PRIMARY
   - For resistance temperature detectors (RTDs), a loop current step response methodology is used as endorsed in NUREG-0809 and described in detail in EPRI report NP-834 (Vol. 1).
   - For newly installed pressure sensors or refurbished pressure sensors whose response time may have been adversely affected, the EPRI developed method described in report NP-267 shall be used. This pressure ramp testing is also discussed in ISA dS-67.06. See the Technical Specifications Bases for SR 3.3.1.16 and SR 3.3.2.10.

AUXILIARY - RTDs and pressure sensors may be tested using the noise analysis method which will function on the principle that, in the protection system, sensors are sensitive to process noise created by natural perturbations in variables, including temperature, pressure, and flow. The noise analysis method testing system is designed to measure sensor response time and/or assess degradation by measurement of the sensors' efficiency to detect high-frequency noise.

Nuclear instrumentation detectors are excluded since delays attributable to them are negligible in the overall channel response time required for safety.

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

The time response of discrete portions of the system can be measured or allocated, and overall response times can be determined by summing the response times of those discrete components. The wires that connect the discrete components do not necessarily require time response testing since wiring delays are typically insignificant compared with the response times of the individual components.

c. The reliability goals specified in Section 4.2 of IEEE Standard 338-1971 are consistent with the test frequency in the Callaway Technical Specifications.

d. The periodic time interval discussed in Section 4.3 of IEEE Standard 338-1971, and specified in the Callaway Technical Specifications, is selected to ensure that equipment associated with protection functions has not drifted beyond its minimum performance requirements. The adequacy of the interval will be verified by results of testing or the interval will be reevaluated on the basis of actual experience.

e. The test interval discussed in Section 5.2 of IEEE Standard 338-1971 is developed primarily on past operating experience and modified, if necessary, to ensure that system and subsystem protection is reliably provided.

7.1.3 REFERENCES

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

2. Letter dated April 20, 1977, R.L. Tedesco (NRC) to C. Eicheldinger (Westinghouse).

3. Letter dated February 27, 1984, N.A. Petrick (SNUPPS) to Mr. Harold R. Denton (NRC), SLNRC 84-0038.

4. Gangloff, W.C. and Loftus, W.D., "An Evaluation of Solid State Logic Reactor Protection in Anticipated Transients," WCAP-7706-L (Proprietary) and WCAP-7706 (Non-Proprietary), July, 1971.

5. Operating License Amendment 137 dated September 25, 2000.

6. Gruber, T. J. and Harbaugh, T. D., “Westinghouse SSPS Universal Logic Board Replacement Summary Report 6D30225G01/G02/G03/G04,” WCAP-16769-P, Revision 2, February, 2011.

7. Harbaugh, T. D. and Hines, E. F., “Westinghouse SSPS Safeguards Driver Board Replacement Summary Report 6D30252G01/G02,” WCAP-16770-P, Revision 0, August, 2008.

8. Gruber, T. J. and Harbaugh, T. D., “Westinghouse SSPS Undervoltage Driver Board Replacement Summary Report 6D30350G01/G02,”WCAP-16771-P, Revision 1, April, 2011.

TABLE 7.1-1 INSTRUMENTATION SYSTEMS IDENTIFICATION

Safety-Related Systems or Categories	Designer: Westinghouse	Designer: Bechtel	Similar To Plant: Comanche Peak	Similar To Plant: W. B. McGuire and Watts Bar	Similar To Plant: Other	Remarks
1. Reactor trip system	X		X	X		
2. Engineered safety feature actuation systems						
a. Main steam and feedwater isolation	X	X				New (see 7.3.7)
b. Containment combustible gas control		X			Millstone Unit 2	
c. Containment purge isolation		X				New (see 7.3.2)
d. Fuel building ventilation isolation		X			-----	New (see 7.3.3)
e. Control room ventilation isolation		X			-----	New (see 7.3.4)
f. Auxiliary feedwater supply	X	X	X	X	-----	New supply configuration (see 7.3.6)
g. NSSS ESFAS	X		X			
3. Systems required for safe shutdown						
a. Hot standby	X	X	X	X		
b. Cold shutdown	X	X	X	X		
c. Safe shutdown from outside control room	X	X	X		-----	New (see 7.4.3)
4. Safety-related display instrumentation						
a. Reactor trip system	X		X	X		
b. Engineering safety feature actuation systems	X	X	X	X		
c. Systems required for safe shutdown	X	X	X	X		
5. Other instrumentation systems required for safety						
a. Instrumentation and control power supply system		X			Trojan	
b. Residual heat removal system isolation valve interlocks	X		X			
c. Refueling interlocks	X		X			

TABLE 7.1-1 (Sheet 2)

Safety-Related Systems or Categories	Designer: Westinghouse	Designer: Bechtel	Similar To Plant: Comanche Peak	Similar To Plant: W. B. McGuire and Watts Bar	Similar To Plant: Other	Remarks
d. Accumulator motor-operated isolation valve interlocks	X		X			
e. ECCS switchover from injection mode to recirculation mode	X		X			
f. Interlocks for RCS pressure control during low temperature operation	X		X			*
g. Isolation of nonseismic Category I piping from seismic Category I cooling systems		X				New (See 7.6.7 and 7.6.8)
h. Interlocks for pressurizer pressure relief system	X		X			
i. Switchover of charging pump suction to RWST on low-low VCT level	X		X			**
j. Instrumentation for mitigating consequences of inadvertent boron dilution	X		X			
k. Charging pump miniflow interlock	X				Seabrook	
l. Neutron flux monitoring		X	X			New (See 7.6.14)

* Callaway arms circuit manually

** Callaway has a third VCT level instrument channel

CALLAWAY PLANT

TABLE 7.1-2 IDENTIFICATION OF SAFETY CRITERIA

SHEET 1

SYSTEM / SAFETY CRITERIA

NRC GENERAL DESIGN CRITERIA (NOTE 1 AND 5)		REACTOR TRIP SYSTEM (RTS): SECTION 7.2	ESFS (SECTION 7.3): CONTAINMENT COMBUSTIBLE GAS CONTROL (SECTION 7.3.1)	CONTAINMENT PURGE ISOLATION (SECTION 7.3.2)	FUEL BUILDING VENTILATION ISOLATION (SECTION 7.3.3)	CONTROL ROOM VENTILATION ISOLATION (SECTION 7.3.4)	AUXILIARY FEEDWATER SUPPLY (SECTION 7.3.6)	MAIN STEAM AND FEEDWATER ISOLATION (SECTION 7.3.7)	NSSS ESFAS (SECTION 7.3.8)	SAFE SHUTDOWN (SECTION 7.4): AUXILIARY FEEDWATER CONTROL (SECTION 7.4.1.1)	ATMOSPHERIC STEAM RELIEF VALVES (SECTION 7.4.1.2)	CENTRIFUGAL CHARGING SYSTEM CONTROLS (APP. 5.4A)	ESSENTIAL SERVICE WATER (APP. 5.4A)	COMPONENT COOLING WATER (APP. 5.4A)	CONTAINMENT COOLERS (APP. 5.4A)	EMERGENCY DIESEL GENERATORS (APP. 5.4A)	CONTROL ROOM VENTILATION (APP.5.4A)	EMERGENCY VENTILATION (APP. 5.4A)	SPENT FUEL POOL COOLING (APP.5.4A)	REACTOR COOLANT SYSTEM (APP. 5.4A)	MAIN STEAM (APP. 5.4A)	CHEMICAL VOLUME CONTROL SYSTEM (APP. 5.4A)	BORATED REFUELING WATER (APP. 5.4A)	RESIDUAL HEAT REMOVAL (APP. 5.4A)	SAFETY-RELATED PORTION OF INSTRUMENT AIR (APP. 5.4A)	SAFETY INJECTION (APP. 5.4A)	ACCUMULATORS (APP. 5.4A)	SAFE SHUTDOWN FROM OUTSIDE THE CONTROL ROOM (SEE NOTE 9)
I. OVERALL REQUIREMENTS	1 QUALITY STANDARDS AND RECORDS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	2 DESIGN BASES FOR PROTECTION AGAINST NATURAL PHENOMENA	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	3 FIRE PROTECTION	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	4 ENVIRONMENTAL AND MISSLE DESIGN BASES	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	5 SHARING OF STRUCTURES, SYSTEMS, AND COMPONENTS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
II. PROTECTION BY MULTIPLE FISSION PRODUCT BARRIERS	12 SUPPRESSION OF REACTOR POWER OSCILLATIONS	●	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	13 INSTRUMENTATION AND CONTROL	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	14 REACTOR COOLANT PRESSURE BOUNDARY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●	–	●	–	●	–	–	–	–
	15 REACTOR COOLANT SYSTEM DESIGN	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–
	19 CONTROL ROOM	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
III. PROTECTION AND REACTIVITY CONTROL SYSTEMS	20 PROTECTION SYSTEMS FUNCTIONS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	–	–	–	●	●	●	●
	21 PROTECTION SYSTEM RELIABILITY AND TESTABILITY	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	–	–	–	●	●	●	●
	22 PROTECTION SYSTEM INDEPENDENCE	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	–	–	–	●	●	●	●
	23 PROTECTION SYSTEM FAILURE MODES	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	–	–	–	●	●	●	●
	24 SEPARATION OF PROTECTION AND CONTROL SYSTEMS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	25 PROTECTION SYSTEM REQUIREMENTS FOR REACTIVITY CONTROL MALFUNCTIONS	●	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
IV. FLUID SYSTEMS	30 QUALITY OF REACTOR COOLANT PRESSURE BOUNDARY	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	34 RESIDUAL HEAT REMOVAL	–	–	–	–	–	●	–	–	●	●	●	●	●	–	●	–	–	–	●	●	–	–	●	●	–	–	–
	35 EMERGENCY CORE COOLING	–	–	–	–	–	–	–	●	–	–	●	–	–	–	●	–	–	–	●	●	–	–	–	●	–	–	–
	37 TESTING OF EMERGENCY CORE COOLING SYSTEM	–	–	–	–	–	–	–	●	–	–	●	–	–	–	●	–	–	–	●	●	–	–	–	●	–	–	–
	38 CONTAINMENT HEAT REMOVAL	–	–	–	–	–	–	–	●	–	–	–	●	–	●	●	–	–	–	–	–	–	–	–	–	–	–	–
	40 TESTING OF CONTAINMENT HEAT REMOVAL SYSTEM	–	–	–	–	–	–	–	●	–	–	–	●	–	●	●	–	–	–	–	–	–	–	–	–	–	–	–
	41 CONTAINMENT ATMOSPHERE CLEANUP	–	●	●	–	–	–	–	●	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–
	43 TESTING OF CONTAINMENT ATMOSPHERE CLEANUP SYSTEM	–	●	●	–	–	–	–	●	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–
	44 COOLING WATER	–	–	–	–	–	●	–	–	●	–	–	●	●	●	●	–	–	●	–	–	–	–	–	–	–	–	–
	46 TESTING OF COOLING WATER SYSTEM	–	–	–	–	–	●	–	–	●	–	–	●	●	●	●	–	–	●	–	–	–	–	–	–	–	–	–
V. REACTOR CONTAINMENT	54 PIPING SYSTEMS PENETRATING CONTAINMENT	–	●	●	–	–	●	●	–	–	–	–	●	●	–	–	–	–	–	–	–	–	–	–	●	–	–	–
	55 REACTOR COOLANT PRESSURE BOUNDARY PENETRATING CONTAINMENT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–
	56 PRIMARY CONTAINMENT ISOLATION	–	●	●	–	–	●	●	●	–	–	–	●	●	–	–	–	–	–	–	–	–	–	–	●	–	–	–
	57 CLOSED SYSTEMS ISOLATION VALVES	–	–	–	–	–	●	●	–	–	–	–	●	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–
VI. FUEL AND RADIOACTIVITY CONTROL (NOTE 2)	60 CONTROL OF RELEASES OF RADIOACTIVE MATERIALS TO THE ENVIRONMENT	–	●	●	●	–	–	–	–	–	●	–	–	–	●	–	–	●	●	–	–	–	–	–	–	–	–	–
	63 MONITORING FUEL AND WASTE STORAGE	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–
	64 MONITORING RADIOACTIVITY RELEASE	–	–	●	●	–	–	–	–	–	–	–	–	–	–	–	–	●	●	–	–	–	–	–	–	–	–	–

NRC GENERAL DESIGN CRITERIA (NOTE 1 AND 5)		SAFETY-RELATED DISPLAY INSTRUMENTATION (SECTION 7.5) – RTS (SECTION 7.5.1): TRIP PARAMETERS	TRIP STATUS	ESFS (SECTION 7.5.2): ACTUATION PARAMETERS (SECTION 7.5.2.1)	BYPASSES (SECTION 7.5.2.2)	STATUS (SECTION 7.5.2.3)	PERFORMANCE (SECTION 7.5.2.4)	SAFE SHUTDOWN (SECTION 7.5.3): HOT SHUTDOWN CONTROL (SECTION 7.5.3.1)	COLD SHUTDOWN CONTROL (SECTION 7.5.3.2)	BYPASSES (SECTION 7.5.3.3)	STATUS (SECTION 7.5.3.4)	PERFORMANCE (SECTION 7.5.3.5)	ALL OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY (SECTION 7.6): INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEM (SECTION 7.6.1)	RESIDUAL HEAT REMOVAL SYSTEM ISOLATION VALVE INTERLOCKS (SECTION 7.6.2)	REFUELING INTERLOCKS (SECTION 7.6.3)	ACCUMULATOR MOTOR-OPERATED ISOLATION VALVE INTERLOCKS (SECTION 7.6.4)	SWITCHOVER FROM INJECTION TO RECIRCULATION (SECTION 7.6.5)	INTERLOCKS FOR RCS PRESSURE CONTROL DURING LOW TEMPERATURE OPERATION (SECTION 7.6.6)	ISOLATION OF NON-SEISMIC - CATEGORY I COOLING SYSTEMS (SECTIONS 7.6.7 AND 7.6.8)	INTERLOCKS FOR PRESSURIZER PRESSURE RELIEF SYSTEM (SECTION 7.6.10)	SWITCHOVER OF CHARGING PUMP SUCTION TO RWST ON LOW-LOW VCT LEVEL (SECTION 7.6.11)	INSTRUMENTATION FOR MITIGATING CONSEQUENCES OF INADVERTENT BORON DILUTION (SECTION 7.6.12)	CHARGING PUMP MINI-FLOW INTERLOCK (SECTION 7.6.13)	NEUTRON FLUX MONITORING (SECTION 7.6.14)	CONTROL SYSTEMS NOT REQUIRED FOR SAFETY: SECTION 7.7
I. OVERALL REQUIREMENTS	1 QUALITY STANDARDS AND RECORDS	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	–	●	●	●	●	●	●	–
	2 DESIGN BASES FOR PROTECTION AGAINST NATURAL PHENOMENA	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	–	●	●	●	●	●	●	–
	3 FIRE PROTECTION	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	–	●	●	●	●	●	●	–
	4 ENVIRONMENTAL AND MISSLE DESIGN BASES	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	–	●	●	●	●	●	●	–
	5 SHARING OF STRUCTURES, SYSTEMS, AND COMPONENTS	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	–	●	●	●	●	●	●	–
II. PROTECTION BY MULTIPLE FISSION PRODUCT BARRIERS	12 SUPPRESSION OF REACTOR POWER OSCILLATIONS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●
	13 INSTRUMENTATION AND CONTROL	●	●	●		●	●	●	●		●	●	●	●	–	●	●	●	●	–	–	–	–	–	–
	14 REACTOR COOLANT PRESSURE BOUNDARY	–	–	–	–	–	–	–	–	–	–	–	–	●	–	●	–	●	–	–	–	–	–	–	–
	15 REACTOR COOLANT SYSTEM DESIGN	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	●	–	–	–	–	–
	19 CONTROL ROOM	●	●	●	●	●	●	●	●	●	●	●	●	●	–	●	●	●	●	–	–	–	–	–	–
III. PROTECTION AND REACTIVITY CONTROL SYSTEMS	20 PROTECTION SYSTEMS FUNCTIONS	–	–	–	–	–	–	–	–	–	–	–	●	●	–	●	●	–	●	●	●	●	–	–	–
	21 PROTECTION SYSTEM RELIABILITY AND TESTABILITY	–	–	–	–	–	–	–	–	–	–	–	●	●	–	●	●	–	●	–	–	–	–	–	–
	22 PROTECTION SYSTEM INDEPENDENCE	–	–	–	–	–	–	–	–	–	–	–	●	●	–	●	●	–	●	–	–	–	–	–	–
	23 PROTECTION SYSTEM FAILURE MODES	–	–	–	–	–	–	–	–	–	–	–	●	●	–	●	●	–	●	–	–	–	–	–	–
	24 SEPARATION OF PROTECTION AND CONTROL SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	●	●	–	●	●	–	●	●	●	●	●	●	●
	25 PROTECTION SYSTEM REQUIREMENTS FOR REACTIVITY CONTROL MALFUNCTIONS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
IV. FLUID SYSTEMS	30 QUALITY OF REACTOR COOLANT PRESSURE BOUNDARY	–	–	–	–	–	–	–	–	–	–	–	–	●	–	●	–	●	–	–	–	–	–	–	–
	34 RESIDUAL HEAT REMOVAL	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	●	–	–	–	–	–	–	–	–
	35 EMERGENCY CORE COOLING	–	–	–	–	–	●	●	–	–	–	●	–	●	–	●	●	–	●	–	–	–	–	–	–
	37 TESTING OF EMERGENCY CORE COOLING SYSTEM	–	–	●	–	–	●	●	–	–	–	●	–	●	–	●	●	–	●	–	–	–	–	–	–
	38 CONTAINMENT HEAT REMOVAL	–	–	–	–	–	●	●	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–
	40 TESTING OF CONTAINMENT HEAT REMOVAL SYSTEM	–	–	●	–	–	●	●	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–
	41 CONTAINMENT ATMOSPHERE CLEANUP	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	43 TESTING OF CONTAINMENT ATMOSPHERE CLEANUP SYSTEM	–	–	●	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	44 COOLING WATER	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–
	46 TESTING OF COOLING WATER SYSTEM	–	–	●	–	–	●	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–
V. REACTOR CONTAINMENT	54 PIPING SYSTEMS PENETRATING CONTAINMENT	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–
	55 REACTOR COOLANT PRESSURE BOUNDARY PENETRATING CONTAINMENT	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–
	56 PRIMARY CONTAINMENT ISOLATION	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	57 CLOSED SYSTEMS ISOLATION VALVES	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–
VI. FUEL AND RADIOACTIVITY CONTROL (NOTE 2)	60 CONTROL OF RELEASES OF RADIOACTIVE MATERIALS TO THE ENVIRONMENT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	63 MONITORING FUEL AND WASTE STORAGE	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	64 MONITORING RADIOACTIVITY RELEASE	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–

CALLAWAY PLANT

SHEET 2

SYSTEM / **SAFETY CRITERIA**

Group	Safety Criteria	Reactor Trip System (RTS): Section 7.2	ESFS (Section 7.3): Containment Combustible Gas Control (Section 7.3.1)	Containment Purge Isolation (Section 7.3.2)	Fuel Building Ventilation Isolation (Section 7.3.3)	Control Room Ventilation Isolation (Section 7.3.4)	Auxiliary Feedwater Supply (Section 7.3.6)	Main Steam and Feedwater Isolation (Section 7.3.7)	NSSS ESFAS (Section 7.3.8)	Systems Required for Safe Shutdown (Section 7.4): Auxiliary Feedwater Control (Section 7.4.1.1)	Atmospheric Steam Relief Valves (Section 7.4.1.2)	Centrifugal Charging System Controls (App. 5.4A)	Essential Service Water (App. 5.4A)	Component Cooling Water (App. 5.4A)	Containment Coolers (App. 5.4A)	Emergency Diesel Generators (App. 5.4A)	Control Room Ventilation (App. 5.4A)	Emergency Ventilation (App. 5.4A)	Spent Fuel Pool Cooling (App. 5.4A)	Reactor Coolant System (App. 5.4A)	Main Steam (App. 5.4A)	Chemical Volume Control System (App. 5.4A)	Borated Refueling Water (App. 5.4A)	Residual Heat Removal (App. 5.4A)	Safety-Related Portion of Instrument Air (App. 5.4A)	Safety Injection (App. 5.4A)	Accumulators (App. 5.4A)	Safe Shutdown from Outside the Control Room (See Note 9)
NRC REGULATORY GUIDES (NOTE 4)	1.7 CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT FOLLOWING A LOSS OF COOLANT ACCIDENT	–	●	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.11 INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT	–	●	●	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.21 MEASURING AND REPORTING OF EFFLUENTS FROM NUCLEAR POWER PLANTS	–	–	●	●	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–
	1.22 PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS (NOTE 3a)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	–	–	●
	1.26 QUALITY GROUP CLASSIFICATIONS AND STANDARDS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.29 SEISMIC DESIGN CLASSIFICATION	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.30 QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING OF INSTRUMENTATION AND ELECTRIC EQUIPMENT (NOTE 3b)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.33 QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATION)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.40 QUALIFICATION TESTS OF CONTINUOUS-DUTY MOTORS INSTALLED INSIDE THE CONTAINMENT OF WATER-COOLED NUCLEAR POWER PLANTS (NOTE 3c)	–	●	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.45 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS (NOTE 3a)	–	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.47 BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS (NOTE 3a)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–
	1.53 APPLICATION OF THE SINGLE-FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS (NOTES 3a and 3d)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.62 MANUAL INITIATION OF PROTECTIVE ACTIONS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.63 ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR LIGHT-WATER-COOLED NUCLEAR POWER PLANTS (NOTE 3a)	●	●	–	–	–	–	–	●	–	–	–	●	●	●	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.68 INITIAL TEST PROGRAM FOR WATER-COOLED REACTOR POWER PLANTS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.73 QUALIFICATION TESTS OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER PLANTS (NOTE 3f)	–	●	●	–	–	–	–	–	–	–	–	●	●	●	–	–	–	–	●	–	–	–	●	–	●	–	–
	1.75 PHYSICAL INDEPENDENCE OF ELECTRIC SYSTEMS (NOTES 3a and 3g)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.80 PREOPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS	–	–	–	–	–	●	●	–	●	●	–	●	–	–	●	–	–	–	Superceded by R.G. 1.68.3								–
	1.89 QUALIFICATION OF CLASS IE EQUIPMENT FOR NUCLEAR POWER PLANTS (NOTES 3h and 3i)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.97 INSTRUMENTATION FOR LIGHT-WATER COOLED NUCLEAR POWER PLANTS TO ASSESS PLANT AND ENVIRONS CONDITIONS DURING AND FOLLOWING AN ACCIDENT (ICSB BTP 23)	–	●	–	–	–	–	–	–	–	–	–	–	–	–	●	–	–	–	●	–	–	●	●	–	–	●	–
	1.100 SEISMIC QUALIFICATION OF ELECTRIC EQUIPMENT FOR NUCLEAR POWER PLANTS (NOTE 3i) (ICSB BTP 10)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.105 INSTRUMENT SETPOINTS	●	–	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	●	–	–	●	●	–
	1.106 THERMAL OVERLOAD PROTECTION FOR ELECTRIC MOTORS ON MOTOR OPERATED VALVES (ICSB BTP 27)	–	●	●	●	●	●	–	–	●	–	●	●	●	●	–	●	●	●	●	–	–	–	–	–	–	–	–
	1.118 PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS (NOTES 3a, 3j, and 3k)	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●
	1.139 GUIDANCE FOR RESIDUAL HEAT REMOVAL (SEE SECTION 5.0 APPENDIX 5.4A)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●	●	●	●	●	–	●	●	–
SAFETY RELATED	SAFETY RELATED AS DEFINED IN SECTION 7.1.1	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	●	–	●	●	●
IEEE STANDARD	279 CRITERIA FOR PROTECTION SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●

Group	Safety Criteria	Safety-Related Display Instrumentation (Section 7.5): RTS (Section 7.5.1): Trip Parameters	Trip Status	ESFS (Section 7.5.2): Actuation Parameters (Section 7.5.2.1)	Bypasses (Section 7.5.2.2)	Status (Section 7.5.2.3)	Performance (Section 7.5.2.4)	Safe Shutdown (Section 7.5.3): Hot Shutdown Control (Section 7.5.3.1)	Cold Shutdown Control (Section 7.5.3.2)	Bypasses (Section 7.5.3.3)	Status (Section 7.5.3.4)	Performance (Section 7.5.3.5)	All Other Instrumentation Systems Required for Safety (Section 7.6): Instrumentation and Control Power Supply System (Section 7.6.1)	Residual Heat Removal System Isolation Valve Interlocks (Section 7.6.2)	Refueling Interlocks (Section 7.6.3)	Accumulator Motor-Operated Isolation Valve Interlocks (Section 7.6.4)	Switchover from Injection to Recirculation (Section 7.6.5)	Interlocks for RCS Pressure Control During Low Temperature Operation (Section 7.6.6)	Isolation of Non-Seismic - Category I Cooling Systems (Sections 7.6.7 and 7.6.8)	Interlocks for Pressurizer Pressure Relief System (Section 7.6.10)	Switchover of Charging Pump Suction to RWST on Low-Low VCT Level (Section 7.6.11)	Instrumentation for Mitigating Consequences of Inadvertent Boron Dilution (Section 7.6.12)	Charging Pump Mini-Flow Interlock (Section 7.6.13)	Neutron Flux Monitoring (Section 7.6.14)	Control Systems Not Required for Safety: Section 7.7
NRC REGULATORY GUIDES (NOTE 4)	1.7 CONTROL OF COMBUSTIBLE GAS CONCENTRATIONS IN CONTAINMENT FOLLOWING A LOSS OF COOLANT ACCIDENT	–	–	●	–	–	●	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.11 INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●
	1.21 MEASURING AND REPORTING OF EFFLUENTS FROM NUCLEAR POWER PLANTS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●
	1.22 PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS (NOTE 3a)	–	–	●	–	–	●	●	●	–	–	●	●	●	–	●	●	●	●	●	●	–	●	–	–
	1.26 QUALITY GROUP CLASSIFICATIONS AND STANDARDS	–	–	–	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	–	–	–	–	–	●
	1.29 SEISMIC DESIGN CLASSIFICATION	–	–	–	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	●	–
	1.30 QUALITY ASSURANCE REQUIREMENTS FOR THE INSTALLATION, INSPECTION, AND TESTING OF INSTRUMENTATION AND ELECTRIC EQUIPMENT (NOTE 3b)	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	●	–
	1.33 QUALITY ASSURANCE PROGRAM REQUIREMENTS (OPERATION)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.40 QUALIFICATION TESTS OF CONTINUOUS-DUTY MOTORS INSTALLED INSIDE THE CONTAINMENT OF WATER-COOLED NUCLEAR POWER PLANTS (NOTE 3c)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.45 REACTOR COOLANT PRESSURE BOUNDARY LEAKAGE DETECTION SYSTEMS (NOTE 3a)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
	1.47 BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS (NOTE 3a)	–	●	–	●	●	–	–	–	●	●	–	●	●	–	●	●	●	●	●	●	●	●	–	–
	1.53 APPLICATION OF THE SINGLE-FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS (NOTES 3a and 3d)	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	●	–
	1.62 MANUAL INITIATION OF PROTECTIVE ACTIONS	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	–	–
	1.63 ELECTRIC PENETRATION ASSEMBLIES IN CONTAINMENT STRUCTURES FOR LIGHT-WATER-COOLED NUCLEAR POWER PLANTS (NOTE 3a)	–	–	●	●	●	●	●	●	●	●	●	–	●	–	●	–	–	●	–	–	–	–	–	–
	1.68 INITIAL TEST PROGRAM FOR WATER-COOLED REACTOR POWER PLANTS	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	–	–	–	–	–	–
	1.73 QUALIFICATION TESTS OF ELECTRIC VALVE OPERATORS INSTALLED INSIDE THE CONTAINMENT OF NUCLEAR POWER PLANTS (NOTE 3f)	–	–	–	–	–	–	–	–	–	–	–	–	●	–	●	–	–	●	–	–	–	–	–	–
	1.75 PHYSICAL INDEPENDENCE OF ELECTRIC SYSTEMS (NOTES 3a and 3g)	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	●	–
	1.80 PREOPERATIONAL TESTING OF INSTRUMENT AIR SYSTEMS	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	●	Superceded by R.G. 1.68.3					
	1.89 QUALIFICATION OF CLASS IE EQUIPMENT FOR NUCLEAR POWER PLANTS (NOTES 3h and 3i)	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	●	–
	1.97 INSTRUMENTATION FOR LIGHT-WATER COOLED NUCLEAR POWER PLANTS TO ASSESS PLANT AND ENVIRONS CONDITIONS DURING AND FOLLOWING AN ACCIDENT (ICSB BTP 23)	–	–	●	–	–	–	●	–	–	–	–	●	–	–	–	●	–	–	–	–	–	–	–	–
	1.100 SEISMIC QUALIFICATION OF ELECTRIC EQUIPMENT FOR NUCLEAR POWER PLANTS (NOTE 3i) (ICSB BTP 10)	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	●	–
	1.105 INSTRUMENT SETPOINTS	–	–	–	–	–	–	–	–	–	–	–	–	●	–	●	●	●	●	●	●	●	●	–	–
	1.106 THERMAL OVERLOAD PROTECTION FOR ELECTRIC MOTORS ON MOTOR OPERATED VALVES (ICSB BTP 27)	–	–	–	–	–	–	–	–	–	–	–	–	●	–	●	●	–	●	–	–	–	–	–	–
	1.118 PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS (NOTES 3a, 3j, and 3k)	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	●	●	●	–
	1.139 GUIDANCE FOR RESIDUAL HEAT REMOVAL (SEE SECTION 5.0 APPENDIX 5.4A)	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
SAFETY RELATED	SAFETY RELATED AS DEFINED IN SECTION 7.1.1	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	–	●	–	–
IEEE STANDARD	279 CRITERIA FOR PROTECTION SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS	–	–	●	–	–	–	●	●	–	–	–	●	●	–	●	●	●	●	●	●	–	●	●	–

CALLAWAY PLANT

SHEET 3

SYSTEM / SAFETY CRITERIA

NRC ICSB BRANCH TECHNICAL POSITIONS

Safety criteria	REACTOR TRIP SYSTEM (RTS): SECTION 7.2	ENGINEERED SAFETY FEATURE SYSTEMS (ESFS) (SECTION 7.3): CONTAINMENT COMBUSTIBLE GAS CONTROL (SECTION 7.3.1)	CONTAINMENT PURGE ISOLATION (SECTION 7.3.2)	FUEL BUILDING VENTILATION ISOLATION (SECTION 7.3.3)	CONTROL ROOM VENTILATION ISOLATION (SECTION 7.3.4)	AUXILIARY FEEDWATER SUPPLY (SECTION 7.3.6)	MAIN STEAM AND FEEDWATER ISOLATION (SECTION 7.3.7)	NSSS ESFAS (SECTION 7.3.8)	SYSTEMS REQUIRED FOR SAFE SHUTDOWN (SECTION 7.4): AUXILIARY FEEDWATER CONTROL (SECTION 7.4.1.1)	ATMOSPHERIC STEAM RELIEF VALVES (SECTION 7.4.1.2)	CENTRIFUGAL CHARGING SYSTEM CONTROLS (APP. 5.4A)	ESSENTIAL SERVICE WATER (APP. 5.4A)	COMPONENT COOLING WATER (APP. 5.4A)	CONTAINMENT COOLERS (APP. 5.4A)	EMERGENCY DIESEL GENERATORS (APP. 5.4A)	CONTROL ROOM VENTILATION (APP.5.4A)	EMERGENCY VENTILATION (APP. 5.4A)	SPENT FUEL POOL COOLING (APP.5.4A)	REACTOR COOLANT SYSTEM (APP. 5.4A)	MAIN STEAM (APP. 5.4A)	CHEMICAL VOLUME CONTROL SYSTEM (APP. 5.4A)	BORATED REFUELING WATER (APP. 5.4A)	RESIDUAL HEAT REMOVAL (APP. 5.4A)	SAFETY-RELATED PORTION OF INSTRUMENT AIR (APP. 5.4A)	SAFETY INJECTION (APP. 5.4A)	ACCUMULATORS (APP. 5.4A)	SAFE SHUTDOWN FROM OUTSIDE THE CONTROL ROOM (SEE NOTE 9)
1 BACKFITTING OF THE PROTECTION AND EMERGENCY POWER SYSTEMS OF NUCLEAR REACTORS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3 ISOLATION OF LOW PRESSURE SYSTEMS FROM THE HIGH PRESSURE REACTOR COOLANT SYSTEM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4 REQUIREMENTS ON MOTOR-OPERATED VALVES IN THE ECCS ACCUMULATOR LINES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	●	●	-
5 SCRAM BREAKER TEST REQUIREMENTS TECHNICAL SPECIFICATIONS	●	-	-	-	-	-	-	●	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9 DEFINITION AND USE OF "CHANNEL CALIBRATION" - TECHNICAL SPECIFICATIONS	●	-	-	-	-	-	-	●	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12 PROTECTION SYSTEM TRIP POINT CHANGES FOR OPERATION WITH REACTOR COOLANT PUMPS OUT OF SERVICE	●	-	-	-	-	-	-	●	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13 DESIGN CRITERIA FOR AUXILIARY FEEDWATER SYSTEMS	-	-	-	-	-	●	-	●	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14 SPURIOUS WITHDRAWALS OF SINGLE CONTROL RODS IN PRESSURIZED WATER REACTORS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 REACTOR COOLANT PUMP BREAKER QUALIFICATION	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16 CONTROL ELEMENT ASSEMBLY (CEA) INTERLOCKS IN COMBUSTION ENGINEERING REACTORS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18 APPLICATION OF THE SINGLE FAILURE CRITERION TO MANUALLY-CONTROLLED ELECTRICALLY-OPERATED VALVES	-	●	●	●	●	●	-	-	●	-	●	●	●	●	●	●	●	●	-	-	●	-	●	-	-	●	●
19 ACCEPTABILITY OF DESIGN CRITERIA FOR HYDROGEN MIXING AND DRYWELL VACUUM RELIEF SYSTEMS	-	●	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20 DESIGN OF INSTRUMENTATION AND CONTROLS PROVIDED TO ACCOMPLISH CHANGEOVER FROM INJECTION TO RECIRCULATION MODE	-	-	-	-	-	-	-	●	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	●	-	-
21 GUIDANCE FOR APPLICATION OF REGULATORY GUIDE 1.47, "BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS"	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	-
22 GUIDANCE FOR APPLICATION OF REGULATORY GUIDE 1.22, "PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS"	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	●	-	-	-	-	●
25 GUIDANCE FOR THE INTERPRETATION OF GENERAL DESIGN CRITERION 37 FOR TESTING THE OPERABILITY OF THE EMERGENCY CORE COOLING SYSTEM AS A WHOLE	-	-	-	-	-	-	-	●	-	-	●	-	-	-	●	-	-	-	-	-	-	-	-	-	-	-	-
26 REQUIREMENT OF REACTOR PROTECTION SYSTEM ANTICIPATORY TRIPS	●	-	-	-	-	-	-	●	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Safety criteria	SAFETY-RELATED DISPLAY INSTRUMENTATION (SECTION 7.5): RTS (SECTION 7.5.1): TRIP PARAMETERS	TRIP STATUS	ESFS (SECTION 7.5.2): ACTUATION PARAMETERS (SECTION 7.5.2.1)	BYPASSES (SECTION 7.5.2.2)	STATUS (SECTION 7.5.2.3)	PERFORMANCE (SECTION 7.5.2.4)	SAFE SHUTDOWN (SECTION 7.5.3): HOT SHUTDOWN CONTROL (SECTION 7.5.3.1)	COLD SHUTDOWN CONTROL (SECTION 7.5.3.2)	BYPASSES (SECTION 7.5.3.3)	STATUS (SECTION 7.5.3.4)	PERFORMANCE (SECTION 7.5.3.5)
1	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-
9	●	-	●	-	-	●	●	●	-	-	-
12	●	-	●	-	-	●	●	●	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-
20	-	-	●	-	-	-	-	-	-	-	-
21	-	●	-	●	●	-	-	-	●	●	-
22	-	-	●	-	-	●	●	●	-	-	●
25	-	-	●	-	-	●	●	-	-	-	●
26	-	-	-	-	-	-	-	-	-	-	-

Safety criteria	ALL OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY (SECTION 7.6): INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEM (SECTION 7.6.1)	RESIDUAL HEAT REMOVAL SYSTEM ISOLATION VALVE INTERLOCKS (SECTION 7.6.2)	REFUELING INTERLOCKS (SECTION 7.6.3)	ACCUMULATOR MOTOR-OPERATED ISOLATION VALVE INTERLOCKS (SECTION 7.6.4)	SWITCHOVER FROM INJECTION TO RECIRCULATION (SECTION 7.6.5)	INTERLOCKS FOR RCS PRESSURE CONTROL DURING LOW TEMPERATURE OPERATION (SECTION 7.6.6)	ISOLATION OF NON-SEISMIC - CATEGORY I COOLING SYSTEMS (SECTIONS 7.6.7 AND 7.6.8)	INTERLOCKS FOR PRESSURIZER PRESSURE RELIEF SYSTEM (SECTION 7.6.10)	SWITCHOVER OF CHARGING PUMP SUCTION TO RWST ON LOW-LOW VCT LEVEL (SECTION 7.6.11)	INSTRUMENTATION FOR MITIGATING CONSEQUENCES OF INADVERTENT BORON DILUTION (SECTION 7.6.12)	CHARGING PUMP MINI-FLOW INTERLOCK (SECTION 7.6.13)	NEUTRON FLUX MONITORING (SECTION 7.6.14)	CONTROL SYSTEMS NOT REQUIRED FOR SAFETY: SECTION 7.7
1	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	●	-	●	-	●	-	-	-	-	-	-	-
4	-	-	-	●	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-	●
15	-	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-	-
18	-	●	-	●	●	-	●	-	●	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-	-	-	-
20	-	-	-	-	●	-	-	-	●	-	-	-	-
21	●	●	-	●	●	●	●	●	●	●	●	-	-
22	●	●	-	●	●	●	●	●	●	-	●	-	-
25	-	●	-	●	●	-	●	-	-	-	-	-	-
26	-	-	-	-	-	-	-	-	-	-	-	-	-

● APPLICABLE WITH QUALIFICATIONS IDENTIFIED IN TEXT

– NOT APPLICABLE

NOTES:

1. CONFORMANCE TO THE GENERAL DESIGN CRITERIA AND REGULATORY GUIDES IS ADDRESSED IN CHAPTER 3.0.
2. CONFORMANCE TO GDCs 60, 63, AND 64 ARE ADDRESSED IN SECTIONS 11.5 AND 12.3.4.
3. INCLUDES DISCUSSION OF COMPLIANCE WITH IEEE:
   a. 279, b. 336, c. 334, d. 379, e. 317, f. 382, g. 384, h. 323, i. 344, j. 338, and k. 308.
4. THE FOLLOWING REGULATORY GUIDES LISTED IN STANDARD REVIEW PLAN TABLE 7-1 ARE MORE APPLICABLE TO OTHER SECTIONS OF THE FSAR AND ARE DISCUSSED ELSEWHERE. SEE SECTION 3A FOR AN INDEX OF THE CROSS-REFERENCES TO THESE OTHER SECTIONS.

   REGULATORY GUIDES:
   1.6– INDEPENDENCE BETWEEN REDUNDANT STANDBY (ONSITE) POWER SOURCES AND BETWEEN THEIR DISTRIBUTION SYSTEMS
   1.12– INSTRUMENTATION FOR EARTHQUAKES
   1.32– USE OF IEEE STANDARD 308 "CRITERIA FOR CLASS IE ELECTRIC SYSTEMS FOR NUCLEAR POWER GENERATING STATIONS"
   1.67– INSTALLATION OF OVERPRESSURE PROTECTION DEVICES
   1.70– STANDARD FORMAT AND CONTENT OF SAFETY ANALYSIS REPORTS FOR NUCLEAR POWER PLANTS
   1.78– ASSUMPTIONS FOR EVALUATING THE HABITABILITY OF A NUCLEAR POWER PLANT CONTROL ROOM DURING A POSTULATED HAZARDOUS CHEMICAL RELEASE
   1.95– PROTECTION OF NUCLEAR POWER PLANT CONTROL ROOM OPERATORS AGAINST ACCIDENTAL CHLORINE RELEASES
   1.120– FIRE PROTECTION GUIDELINES FOR NUCLEAR POWER PLANTS
5. THE FOLLOWING GDCs LISTED IN STANDARD REVIEW PLAN TABLE 7-1 ARE MORE APPLICABLE TO OTHER SECTIONS OF THE FSAR AND ARE DISCUSSED ELSEWHERE. SEE SECTION 3.1 FOR AN INDEX OF THE CROSS-REFERENCES TO THESE OTHER SECTIONS.

   GDCs:
   10– REACTOR DESIGN
   26– REACTIVITY CONTROL SYSTEM REDUNDANCY AND CAPABILITY
   27– COMBINED REACTIVITY CONTROL SYSTEMS CAPABILITY
   28– REACTIVITY LIMITS
   29– PROTECTION AGAINST ANTICIPATED OPERATIONAL OCCURRENCES
   33– REACTOR COOLANT MAKEUP
   50– CONTAINMENT DESIGN BASIS
6. THE IEEE STANDARDS LISTED IN STANDARD REVIEW PLAN TABLE 7-1 ARE ALL TREATED UNDER THE DISCUSSION OF APPLICABLE REGULATORY GUIDES. SEE NOTE 4.
7. 10CFR50 PARAGRAPHS 34 AND 55a ARE VERY BROAD IN SCOPE AND COVER THE ENTIRE FSAR AND ARE NOT SPECIFIC TO CHAPTER 7.0. PARAGRAPH 36 ON TECHNICAL SPECIFICATIONS IS COVERED SEPARATELY.
8. THE FOLLOWING BRANCH TECHNICAL POSITIONS LISTED IN STANDARD REVIEW PLAN TABLE 7-1 HAVE BEEN REPLACED BY REGULATORY GUIDES WHICH ARE DISCUSSED AT LENGTH ELSEWHERE IN THE FSAR. SEE SECTION 3A FOR AN INDEX OF THE CROSS-REFERENCES TO THESE OTHER FSAR SECTIONS. THESE REGULATORY GUIDES ARE LISTED ON SHEET 2 OF TABLE 7.1-2.

BRANCH TECHNICAL POSITIONS	REPLACEMENT REGULATORY GUIDE
ICSB 10	1.100
ICSB 23	1.97
ICSB 24	1.118
ICSB 27	1.106

9. APPLIES ONLY TO THE ESSENTIAL SHORT-TERM INDICATIONS AND CONTROLS.

TABLE 7.1-3 CONFORMANCE TO REGULATORY GUIDE 1.22, REV. 0, 2/72, "PERIODIC TESTING OF PROTECTION SYSTEM ACTUATION FUNCTIONS"

This table demonstrates the conformance of the design of BOP equipment to Regulatory Guide 1.22.

Regulatory Guide 1.22 Position	Union Electric Position
1. The protection system should be designed to permit periodic testing to extend to and include the actuation devices and actuated equipment. (The actuated equipment is included in the periodic tests to provide assurance that the protection system can initiate its operation, as required by General Design criterion 21. This safety guide does not address the functional performance testing of actuated equipment required by other General Design Criteria; neither does it preclude a design that fulfills more than one testing requirement with a single test.)	1. The protection system is designated to permit periodic testing to extend to and include the actuation devices and actuated equipment.
a. The periodic tests should duplicate, as closely as practicable, the performance that is required of the actuation devices in the event of an accident.	1.a. and b. The periodic tests do duplicate, as closely as practicable, the performance that is required of the actuation devices in the event of an accident. The only actuation devices for which the tests do not completely duplicate the performance that is required in the event of an accident are:
b. The protection system and the systems whose operation it initiates should be designed to permit testing of the actuation devices during reactor operation.	i. The manual actuation switches for RTS and ESFAS--See Section 7.1.2.5.2.

TABLE 7.1-3 (Sheet 2)

Regulatory Guide 1.22 Position	Union Electric Position
	ii. The main turbine trip function--a trip of the main turbine under power-generating conditions would result in a trip of the reactor. The turbine trip function can be fully tested whenever the turbine is not in operation. Testing of the main turbine trip function is further discussed in Section 10.2.3.6. iii. The main steam and feed-water isolation valve actuators--full performance testing of these actuators would result in full closure of the main steam and feedwater isolation valves. The transients that would result under power-generating conditions in the plant would include steam generator water level oscillations, or low-low steam generator water level, and would probably result in reactor trip. The valve actuators can be fully tested, including full closure, whenever the plant is not in operation. iv. The feedwater control valves--See Section 7.1.2.5.2. v. The main feedwater pump trip solenoids--See Section 7.1.2.5.2. vi. The reactor coolant pump seal water return valves--See Section 7.1.2.5.2. vii. Eight selected slave relays--See Section 7.1.2.5.2.

TABLE 7.1-3 (Sheet 3)

Regulatory Guide 1.22 Position	Union Electric Position
2. Acceptable methods of including the actuation devices in the periodic tests of the protection system are: a. Testing simultaneously all actuation devices and actuated equipment associated with each redundant protection system output signal; b. Testing all actuation devices and actuated equipment individually or in judiciously selected groups; c. Preventing the operation of certain actuated equipment during a test of their actuation devices; d. Providing the actuated equipment with more than one actuation device and testing individually each actuation device. Method a. set forth above is the preferable method of including the actuation devices in the periodic tests of the protection system. It shall be noted that the acceptability of each of the four above methods is conditioned by the provisions of Regulatory Positions 3. and 4. below.	2.a. through d. In general, the protection systems can be tested in accordance with method a. The only protection systems that cannot be tested in accordance with method a. are the main steam and feedwater isolation systems and the auxiliary feedwater system. The systems not tested in accordance with method a. can all be tested in accordance with method b. Methods c. and d. need not be used. See Section 10.2.3.6 regarding the main turbine trip system.
3. Where the ability of a system to respond to a bona fide accident signal is intentionally bypassed for the purpose of performing a test during reactor operation:	3.a. and b. System bypasses are generally not required for testing; in most cases, the actuated equipment actually responds to the test signals. The only exceptions to these criteria are:

TABLE 7.1-3 (Sheet 4)

Regulatory Guide 1.22 Position	Union Electric Position
a. Positive means should be provided to prevent expansion of the bypass condition to redundant or diverse systems, and b. Each bypass condition should be individually and automatically indicated to the reactor operator in the main control room.	i. Bistables--test signals are substituted for the actual plant inputs during bistable tests, and provisions are included for bypassing bistable outputs. The bistables not under test, all digital inputs, and all other portions of the protection system are not affected. ii. Main steam and feedwater isolation valves--the signals to these valves are held in a condition that prevents valve motion during a portion of the test. iii. Auxiliary feedwater system--the auxiliary feedwater system configuration is altered during test to prevent accidental injection or auxiliary feedwater into the steam generators and to prevent the introduction of essential service water, which is not chemically controlled, into the chemically controlled portions of the system. Test signal injection into a bistable is effected by means of a momentary test switch so that the normal input signal cannot continue to be overridden after the operator releases the switch. Bistable bypass can be effected only by means of key-lock switches. The keying and access to the keys and to the equipment cabinets is controlled to avoid the possibility of testing or bypassing more than one bistable at any one time. Bistable bypass is indicated by a light and by key position at the location of the bistables and by means of the plant annunciation system in the main control room. Bypass of any portion of the auxiliary feedwater system or of the main steam and feedwater isolation valves is indicated in the main control room.

TABLE 7.1-3 (Sheet 5)

Regulatory Guide 1.22 Position	Union Electric Position
4. Where actuated equipment is not tested during reactor operation, it should be shown that: a. There is no practicable system design that would permit operation of the actuated equipment without adversely affecting the safety or operability of the plant; b. The probability that the protection system will fail to initiate the operation of the actuated equipment is, and can be maintained, acceptably low without testing the actuated equipment during reactor operation, and c. The actuated equipment can be routinely tested when the reactor is shut down.	4. Actuated equipment is tested during reactor operation, except for the equipment addressed in Section 7.1.2.5.2.

TABLE 7.1-4 CONFORMANCE TO REGULATORY GUIDE 1.53, REV. 0, 6/73, "APPLICATION OF THE SINGLE-FAILURE CRITERION TO NUCLEAR POWER PLANT PROTECTION SYSTEMS"

This table demonstrates the conformance of the design of BOP equipment to Regulatory Guide 1.53.

Regulatory Guide 1.53 Position	Union Electric Position
The guidance in trial-use IEEE Std 379-1972 for applying the single-failure criterion to the design and analysis of nuclear power plant protection systems is generally acceptable and provides an adequate interim basis for complying with Section 4.2 of IEEE Std 279-1971, subject to the following:	
1. Because of the trial-use status of IEEE Std 379-1972, it may be necessary in specific instances to depart from one or more of its provisions.	1. Complies with IEEE 379-1972 in its entirety.
2. Section 5.2 of IEEE Std 379-1972 should be supplemented as follows:	2. Complies. The testability of the systems is designed to positively identify failures.
"The detectability of a single failure is predicated on the assumption that the test results in the presence of a failure are different from the results that would be obtained if no failure is present. Thus, inconclusive testing procedures such as "continuity checks" of relay circuit coils in lieu of relay operations should not be considered as adequate bases to classify as detectable all potential failures which could negate the functional capability of the tested device."	

TABLE 7.1-4 (Sheet 2)

Regulatory Guide 1.53 Position	Union Electric Position
3. Section 6.2 of IEEE Std 379-1972 should be supplemented as follows: "Where a single mode switch supplies signals to redundant channels, it should be considered that the single-failure criterion will not be satisfied if either (a) individual switch sections supply signals to redundant channels, or (b) redundant circuits controlled by the switch are separated by less than six inches without suitable barriers."	3. Complies. Switches are either for single trains, or there are two switches, either of which can actuate both trains. For the latter type switch, proper separation is included in the design.
4. Section 6.3 and 6.4 of IEEE Std 379-1972 should be interpreted as not permitting separate failure mode analyses for the protection system logic and the actuator system. The collective protection system logic-actuator system should be analyzed for single-failure modes which, though not negating the functional capability of either portion, act to disable the complete protective function. [An example of such a potential failure mode is a misapplication of Regulatory Guide 1.6 (Safety Guide 6) wherein a single d-c source supplies control power for one channel of protection system logic and for the redundant actuator circuit.]	4. Complies. The FMEA is performed on the basis of a system defined as starting with the sensors and continuing through the actuated devices.

TABLE 7.1-5 CONFORMANCE TO REGULATORY GUIDE 1.62, REV 0, 10/73, "MANUAL INITIATION OF PROTECTIVE ACTIONS"

This table demonstrates the conformance of the design of BOP equipment to Regulatory Guide 1.62.

Regulatory Guide 1.62 Position	Union Electric Position
1. Means should be provided for manual initiation of each protective action (e.g., reactor trip, containment isolation) at the system level, regardless of whether means are also provided to initiate the protective action at the component or channel level (e.g., individual control rod, individual isolation valve).	1. Complies. Manual switches are provided for system actuation.
2. Manual initiation of a protective action at the system level should perform all actions performed by automatic initiation such as starting auxiliary or supporting systems, sending signals to appropriate valve-actuating mechanisms to assure correct valve position, and providing the required action-sequencing functions and interlocks.	2. Complies. Manual actuation of the protective systems will have the same result as automatic actuation.
3. The switches for manual initiation of protective actions at the system level should be located in the control room and be easily accessible to the operator so that action can be taken in an expeditious manner.	3. Complies. Manual switches for protective systems are provided in the control room.

TABLE 7.1-5 (Sheet 2)

Regulatory Guide 1.62 Position	Union Electric Position
4. The amount of equipment common to both manual and automatic initiation should be kept to a minimum. It is preferable to limit such common equipment to the final actuation devices and the actuated equipment. However, action-sequencing functions and interlocks (of Position 2) associated with the final actuation devices and actuated equipment may be common if individual manual initiation at the component or channel level is provided in the control room. No single failure within the manual, automatic, or common portions of the protection system should prevent initiation of protective action by manual or automatic means.	4. Complies. The manual and automatic initiation of protective functions are separate.
5. Manual initiation of protective actions should depend on the operation of a minimum of equipment, consistent with 1, 2, 3, and 4 above.	5. Complies. In some cases, one switch will actuate both trains. In all other cases, one switch will actuate one train.
6. Manual initiation of protective action at the system level should be so designed that once initiated, it will go to completion as required in Section 4.16 of IEEE Std 279-1971.	6. Complies. Once manual initiation occurs, the protective action will go to completion.

TABLE 7.1-6 CONFORMANCE TO REGULATORY GUIDE 1.105, REV 1, 11/76, "INSTRUMENT SETPOINTS"

This table demonstrates the conformance of the design of BOP equipment to Regulatory Guide 1.105. The NSSS response to this Regulatory Guide is given in Appendix 3A.

Note that the implementation date for this Regulatory Guide (plants with construction permits docketed after December 15, 1976), is after the construction permit docketing date for the Callaway plant (1974).

Regulatory Guide 1.105 Position	Union Electric Position
The following are applicable to instruments in systems important to safety:	
1. The setpoints should be established with sufficient margin between the technical specification limits for the process variable and the nominal trip setpoints to allow for (a) the inaccuracy of the instrument, (b) uncertainties in the calibration, and (c) the instrument drift that could occur during the interval between calibrations.	1. Complies. The setpoints have been established with sufficient margin to allow for instrument inaccuracies, calibration uncertainties, and potential instrument drift between calibration checks.
2. All setpoints should be established in that portion of the instrument span which ensures that the accuracy, as required by regulatory position 4 below, is maintained. Instruments should be calibrated so as to ensure the required accuracy at the setpoint.	2. Complies. The instrument spans have been established to ensure that the accuracy at setpoint is sufficient.
3. The range selected for the instrumentation should encompass the expected operating range of the process variable being monitored to the extent that saturation does not negate the required action of the instrument.	3. Complies. The instrument ranges have been established to ensure that saturation does not negate the required instrument operation.

TABLE 7.1-6 (Sheet 2)

Regulatory Guide 1.105 Position	Union Electric Position
4. The accuracy of all setpoints should be equal to or better than the accuracy assumed in the safety analysis, which considers the ambient temperature changes, vibration, and other environmental conditions. The instruments should not anneal, stress relieve, or work harden under design conditions to the extent that they will not maintain the required accuracy. Design verification of these instruments should be demonstrated as part of the instrument qualification program recommended in Regulatory Guide 1.89, "Qualification of Class 1E Equipment for Nuclear Power Plants."	4. Complies. The instrument accuracies are adequate to ensure actuation within the limits assumed in the safety analyses, and will not be unacceptably degraded by annealing, stress relieving or work hardening under design conditions. Compliance with Regulatory Guide 1.89 is discussed in Sections 3.11(B), 3.11(N), and Appendix 3A. Note that the accident analyses generally assume absolute values for the various parameters, rather than assuming nominal values with specified accuracies.
5. Instruments should have a securing device on the setpoint adjustment mechanism unless it can be demonstrated by analysis or test that such devices will not aid in maintaining the required setpoint accuracy and minimizing setpoint changes. The securing device should be designed so that it can be secured or released without altering the setpoint and should be under administrative control.	5. Complies. The bistable setpoint adjustments are not accessible when the cabinet doors are closed. Locks are provided on the cabinet doors, and access to the cabinet area is under administrative control. There is sufficient friction in the setpoint adjustment mechanism to ensure that the adjustment will not slip during normal operation or seismic excitation.
6. The assumptions used in selecting the setpoint values in regulatory position 1 and the minimum margin with respect to the limiting safety system settings, setpoint rate of deviation (drift rate), and the relationship of drift rate to testing interval (if any) should be documented.	6. The derivation of the setpoint values from the limiting safety system settings has been thoroughly documented.

TABLE 7.1-7 CONFORMANCE TO REGULATORY GUIDE 1.118, REV 2, 6/78
"PERIODIC TESTING OF ELECTRIC POWER AND PROTECTION SYSTEMS"

This table demonstrates the conformance of the design of BOP equipment to Regulatory Guide 1.118. The NSSS response to this Regulatory Guide is given in Appendix 3A.

Regulatory Guide 1.118 Position	Union Electric Position
The requirements and recommendations contained in IEEE Std 338-1977 are considered acceptable methods for the periodic testing of electric power and protection systems, subject to the following:	
1. The term "safety system" is used in IEEE Std 338-1977 in many places. For the purposes of this guide, "safety system" should be understood to mean, collectively, the electric, instrumentation, and controls portions of the protection system; the protective action system; and auxiliary or supporting features that must be operable for the protection system and protective action system to perform their safety-related functions.	1. Complies. All of the systems listed in position 1 are considered and designed as safety-related systems.
2. Item (6) of Section 5 of IEEE Std 338-1977 lists alternative means of including the actuated equipment in the periodic testing of protection system equipment. The method in which actuated equipment is simultaneously tested with the associated protection system equipment is preferred by the NRC staff; however, overlap testing is acceptable. In addition to the requirements of item (2) in Section 6.1, complete systems tests should be performed at suitable intervals.	2. Complies. Protection systems are tested during operation under conditions specified in Item (6)(a) or (b). Full tests that would interfere with operation are performed with the plant shutdown.
3. Item (11) of Section 5 of IEEE Std 338-1977 should be supplemented by the following: "Where perturbing the monitored variable is not practical, the proposed substitute tests shall be shown to be adequate."	3. Complies. The testing is performed by perturbing the monitored variable wherever practical. Where perturbing the monitored variable is not practical, substitute inputs will be introduced into the sensor.

TABLE 7.1-7 (Sheet 2)

Regulatory Guide 1.118 Position	Union Electric Position
4. Section 5 of IEEE Std 338-1977 should be supplemented by the following: "(13) Means shall be included in the design to prevent the expansion of any bypass condition to redundant channels or load groups during testing operations. Where simulated signals are used to test protective channels or load groups or in other cases where such equipment can be effectively bypassed during a test, care shall be exercised to ensure that more channels are not bypassed than are necessary to perform the test. The remaining channels (those not bypassed) shall provide that safety function consistent with the provisions of item (4) in Section 5 of IEEE Std 338-1977." "(14) Where redundant components are used within a single channel or load group, the design shall permit each to be tested independently."	4. Complies. Bypass of a system does not bypass any other system on the same train or on redundant trains. Redundant components are tested independently.
5. Section 6.3.4 of IEEE Std 338-1977 should be supplemented by the following: "For neutron detectors (1) tests of detector-cable assemblies for increased capacitance, (2) monitoring of noise characteristics of neutron detector signals, or (3) some other test that does not require removal of detectors from their installed location should be used to confirm neutron detector response time characteristics to avoid undue radiation exposure of plant personnel unless such tests are not capable of detecting response time changes beyond acceptable limits."	5. Not applicable. Neutron flux monitors supplied with the BOP do not have response time testing requirements since they are not credited in any Chapter 15 accident analyses and are for post-accident monitoring only. Refer to Table 16.3-1 and to FSAR Appendix 3A (RG 1.118 position), Section 7.1.2.6.2, and the response to NRC Question 640.1 for the justification for excluding the NSSS NIS detectors from the response time testing requirements of IEEE Std 338.

TABLE 7.1-7 (Sheet 3)

Regulatory Guide 1.118 Position	Union Electric Position
6. Section 6.4(5) of IEEE Std 338-1977 should be supplemented by the following:	
". . . makeshift test setups except as follows:	
a. Temporary jumper wires may be used with portable test equipment where the safety system equipment to be tested is provided with facilities specifically designed for connection of this test equipment. These facilities shall meet all the requirements of this standard, whether the portable test equipment is disconnected or remains connected to these facilities.	6.a. Complies. Facilities for connection of test equipment include screw terminal blocks at the back of the cabinet.
b. Removal of fuses or opening a breaker is permitted only if such action causes (1) the trip of the associated protection system channel, or (2) the actuation (startup and operation) of the associated Class 1E load group."	6.b. Complies. Removal of fuses or opening of input circuit breakers is done only if it causes the trip of the associated channel or actuation of the associated load group.
7. In addition to items (1) through (7) of Section 6.5.1 of IEEE Std 338-1977, the ability to detect significant changes in failure rates should be considered in the selection of initial test intervals.	7. Complies. Changes in failure rates are considered in testing intervals.
8. The following provisions of IEEE Std 338-1977 have been added in the 1977 version of this standard. These provisions will be considered by the NRC staff and endorsed or supplemented in a future revision of this regulatory guide.	
a. Section 4, eighth paragraph, now excludes the process to sensor coupling and the actuated equipment to process coupling from response time testing required by the standard.	8.a. Complies with IEEE 338-1977. Process to sensor coupling and actuated equipment to process coupling are not considered in response times.

TABLE 7.1-7 (Sheet 4)

Regulatory Guide 1.118 Position	Union Electric Position
b. Section 5, first paragraph, items (2) and (3) now allow tripping of the channel being tested, or bypass of the equipment consistent with availability requirements, during test of redundant channels or load groups.	8.b. Complies with IEEE 338-1977. Tripping or bypass of channels being tested is done only for the short period of the test.
c. Section 6.6.2, item (8) now only requires listing of anticipated responses in test procedures "when required as a precautionary measure."	8.c. Complies with IEEE 338-1977. The written procedures do provide the anticipated response, when required, as a precautionary measure immediately before the step which will produce the response. The means by which the response is to be observed is included in the acceptance criteria.

7.2 REACTOR TRIP SYSTEM

7.2.1 DESCRIPTION

7.2.1.1 System Description

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

The following systems make up the reactor trip system (see Ref. 1, 2, and 3 for additional background information).

a. Process instrumentation and control system

b. Nuclear instrumentation system

c. Solid state logic protection system

d. Reactor trip switchgear

e. Manual actuation circuit

The reactor trip system consists of sensors that monitor various plant parameters and are connected with analog circuitry, consisting of two to four redundant channels, and digital circuitry, consisting of two redundant logic trains, that receives inputs from the analog channels to complete the logic necessary to automatically open the reactor trip breakers.

Each of two logic trains, A and B, is capable of opening a separate and independent reactor trip breaker, RTA and RTB, respectively. The two trip breakers in series connect three-phase ac power from the rod drive motor generator sets to the rod drive power cabinets, as shown in Figure 7.2-1 (Sheet 2). During plant power operation, a dc undervoltage coil on each reactor trip breaker holds a trip plunger out against its spring, allowing the power to be available at the rod control power supply cabinets. For reactor

trip, a loss of dc voltage to the undervoltage coil, as well as energization of the shunt trip coil, releases the trip plunger and trips open the breaker. When either of the trip breakers opens, power is interrupted to the rod drive power supply, and the control rods fall, by gravity, into the core. The rods cannot be withdrawn until the trip breakers are manually reset. The trip breakers cannot be reset until the abnormal condition which initiated the trip is corrected. Bypass breakers BYA and BYB are provided to permit testing of the trip breakers, as discussed in Section 7.2.2.2.3.

An auto shunt trip design modification has been implemented which monitors the reactor protection system outputs to the reactor trip breakers' undervoltage coils and provides trip signals to the shunt trip coils upon receipt of an automatic trip signal to the undervoltage coils. This was accomplished by providing a rotary type interposing relay between the trip breaker undervoltage coil circuit and the shunt trip coil circuit. This auto shunt trip relay is energized from the reactor protection system voltage which is provided to the undervoltage coil. When the voltage is removed by an automatic reactor trip signal, the auto shunt trip relay will de-energize, closing a contact to energize the shunt trip coil. Thus, the breaker trip shaft will be actuated by both the undervoltage and shunt trip attachments. This design modification applies only to the reactor trip breakers; the bypass breaker shunt trip coils will not receive an automatic trip signal.

The added hardware consists of qualified shunt trip coils and panels which include the relays and test hardware. The shunt trip attachments and auto shunt trip panels are qualified in accordance with IEEE Standards 323-1974 and 344-1975. The panels are mounted at the reactor trip switchgear.

The auto shunt trip panels are provided with two push-button switches for use during periodic on-line testing to independently confirm the operability of the undervoltage and shunt trip attachments. The auto shunt trip block push-button switch is used to prevent the shunt trip coil from energizing when the undervoltage trip is being tested. The auto shunt trip test push-button switch is used to de-energize the auto shunt trip relay, energizing the shunt trip coil while the undervoltage coil remains energized.

The auto shunt trip panels are also equipped with test jacks to facilitate breaker response time testing. These jacks are wired directly to an auxiliary switch contact (closed when the breaker is closed) to provide indication that the breaker has tripped. Another set of test jacks is connected across the auto shunt trip relay coil through resistors to provide indication of trip initiation. The resistors are provided to ensure that accidental shorts or grounds applied through the test points do not result in an inadvertent reactor trip or an overload on the reactor protection system output.

7.2.1.1.1 Functional Performance Requirements

The reactor trip system automatically initiates reactor trip:

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

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

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

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

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

7.2.1.1.2 Reactor Trips

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

Table 7.2-1 provides a list of reactor trips that are described below. Table 7.2-2 provides a listing of all protection system interlocks which are designated P-(number).

a. Nuclear overpower trips

The specific trip functions generated are as follows:

1. Power range high neutron flux trip

The power range high neutron flux trip circuit trips the reactor when two out of the four power range channels exceed the trip setpoint.

There are two bistables, each with its own trip setting used for a high- and a low-range trip setting. The high trip setting provides protection during normal power operation and is always active. The low trip setting, which provides protection during startup, can be manually bypassed when two out of the four power range channels read above approximately 10-percent power (P-10). Three out of the four channels below 10 percent automatically reinstate the trip function.

2. Intermediate range high neutron flux trip

The intermediate range high neutron flux trip circuit trips the reactor when one out of the two intermediate range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup, can be manually blocked if two out of the four power range channels are above P-10. Three out of the four power range channels below this value automatically reinstate the intermediate range high neutron flux trip. The intermediate range channels (including detectors) are separate from the power range channels. The intermediate range channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

3. Source range high neutron flux trip

The source range high neutron flux trip circuit trips the reactor when one out of the two source range channels exceeds the trip setpoint. This trip, which provides protection during reactor startup and plant shutdown, can be manually bypassed when one out of the two intermediate range channels reads above the P-6 setpoint value and is automatically reinstated when both intermediate range channels decrease below the P-6 setpoint value. This trip is also automatically bypassed by two-out-of-four logic from the power range protection interlock (P-10). This trip function can also be reinstated below P-10 by an administrative action requiring manual actuation of two control board mounted switches. Each switch will reinstate the trip function in one out of the two protection logic trains. The source range trip point is set between the P-6 setpoint (source range cutoff power level) and the maximum source range power level. The channels can be individually bypassed at the nuclear instrumentation racks to permit channel testing during plant shutdown or prior to startup. This bypass action is annunciated on the control board.

4. Power range high positive neutron flux rate trip

This circuit trips the reactor when a sudden abnormal increase in nuclear power occurs in two out of the four power range channels. This trip provides DNB protection against certain rod withdrawal at power events and certain partial power, low rod worth, rod ejection accidents (see Sections 15.4.2 and 15.4.8).

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

b. Core thermal overpower trips

The specific trip functions generated are as follows:

1. Overtemperature ΔT trip

This trip protects the core against DNB and trips the reactor on coincidence, as listed in Table 7.2-1, with one set of temperature measurements per loop. The setpoint for this trip is continuously calculated by analog circuitry for each loop by solving the following equation (See Technical Specification Table 3.3.1-1 Note 1 for further details):

$$\Delta T\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[\frac{1}{1+\tau_3 s}\right] \le \Delta T_o\left\{K_1 - K_2\left[\frac{(1+\tau_4 s)}{1+\tau_5 s}T_{avg}\left(\frac{1}{1+\tau_6 s}\right) - T^o_{avg}\right] + K_3(P-2235) - f_1(\Delta I)\right\}$$

Where:

ΔT	=	measured RCS ΔT, °F
ΔT_o	=	indicated ΔT at rated thermal power, °F
T_{avg}	=	measured RCS average temperature, °F
T^o_{avg}	=	referenced T_{avg} at rated thermal power, $\le$ 585.3°F
P	=	measured pressurizer pressure, psig
K_1	=	preset bias reflecting upper limit (see analysis limit in Table 15.0-4)
K_2	=	preset gain which compensates for the effects of temperature on the DNB limits
K_3	=	preset gain which compensates for the effect of pressure on the DNB limits
τ_1 through τ_6	=	preset time constants which compensate for piping, instrument, and signal conditioning time delays, seconds
s	=	laplace transform operator, seconds^{-1}
$f_1(\Delta I)$	=	a function of the neutron flux difference between the upper and lower long ion chambers (refer to Figure 7.2-2).

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

Increases in ΔI beyond a predefined deadband result in a decrease in trip setpoint (refer to Figure 7.2-2).

The required one pressurizer pressure parameter per loop is obtained from separate sensors connected to three pressure taps at the top of the pressurizer. Four pressurizer pressure signals are obtained from the three taps by connecting one of the taps to two pressure transmitters. Refer to Section 7.2.2.3.3 for an analysis of this arrangement.

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

2. Overpower ΔT trip

This trip protects against excessive power (fuel rod rating protection) and trips the reactor on coincidence, as listed in Table 7.2-1, with one set of temperature measurements per loop. The setpoint for each channel is continuously calculated, using the following equation (See Technical Specification Table 3.3.1-1 Note 2 for further details):

$$\Delta T\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[\frac{1}{1+\tau_3 s}\right] \le \Delta T_o\left\{K_4 - K_5\left[\frac{\tau_7 s}{1+\tau_7 s}\right]\left[\frac{1}{1+\tau_6 s}\right]T_{avg} - K_6\left[T_{avg}\left[\frac{1}{1+\tau_6 s}\right] - T^{o'}{}_{avg}\right] - f_2(\Delta I)\right\}$$

Where:

ΔT	=	measured RCS ΔT, °F
ΔT_o	=	indicated ΔT at rated thermal power, °F
$f_2(\Delta I)$	=	a function of the neutron flux difference between upper and lower long ion chambers (zero for OPDT for all input values)
K_4	=	a preset bias reflecting upper limit (see analysis limit in Table 15.0-4)
K_5	=	a constant which compensates for piping and instrument time delay
K_6	=	a constant which compensates for the change in density flow and heat capacity of the water with temperature
$T^{o'}{}_{avg}$	=	indicated T_{avg} at rated thermal power, $\le$ 585.3
T_{avg}	=	measured RCS average temperature, °F

$\tau_1, \tau_2, \tau_3, \tau_6, \tau_7$ = preset time constants for piping, instrument, and signal conditioning time delays, seconds

s = laplace transform operator, $seconds^{-1}$

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

c. Reactor coolant system pressurizer pressure and water level trips

The specific trip functions generated are as follows:

1. Pressurizer low pressure trip

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

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

2. Pressurizer high pressure trip

   The purpose of this trip is to protect the reactor coolant system against system overpressure.

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

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

3. Pressurizer high water level trip

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

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

d. Reactor coolant system low flow trips

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

1. Low reactor coolant flow

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

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

2. Reactor coolant pump undervoltage trip

This trip protects against low flow which can result from loss of voltage to the reactor coolant pump motors (e.g., from loss of offsite power or reactor coolant pump breakers opening).

There is one undervoltage sensing relay connected to each pump at the motor side of each reactor coolant pump breaker. These relays provide an output signal when the pump voltage goes below 76.7 percent of rated bus voltage. Signals from these relays are time delayed to prevent spurious trips caused by short-term voltage perturbations.

3. Reactor coolant pump underfrequency trip

This trip protects against low flow resulting from pump underfrequency, for example a major power grid frequency disturbance. The function of this trip is to trip the reactor for an underfrequency condition greater than approximately 2.4 Hz/second. The setpoint of the underfrequency relays is adjustable between 54 and 60 Hz, typically.

There is one underfrequency sensing relay for each reactor coolant pump motor. Signals from one or both relays from both busses of the pump motors (time delayed to prevent spurious trips caused by short-term frequency perturbations) will trip the reactor if the power

level is above P-7. The coincidence logic and interlocks are given in Table 7.2-1.

e. Steam generator low-low water level trip

The specific trip function generated is low-low steam generator water level trip.

This trip protects the reactor from loss of heat sink. This trip is actuated on two out of four low-low water level signals occurring in any steam generator. The Environmental Allowance Modifier (EAM) circuitry in the low-low level channel provides for two level setpoints corresponding to an adverse and a normal containment environment. A detailed description of the EAM design basis and functional implementation is provided in Reference 5, including a discussion of surveillance testing clarifications.

The logic is shown on Figure 7.2-1 (Sheets 7 and 19).

f. Reactor trip on a turbine trip (anticipatory)

The reactor trip on a turbine trip is actuated by two-out-of-three logic from emergency trip fluid pressure signals or by all closed signals from the turbine steam stop valves. A turbine trip causes a direct reactor trip above P-9. The reactor trip on turbine trip provides additional protection and conservatism beyond that required for the health and safety of the public. This trip is included as part of good engineering practice and prudent design.

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

Components specified for use as sensors for input signals to the reactor protection system for "emergency trip oil pressure low" and "turbine stop valves close" will conform to the requirements of IEEE 279-1971 and be environmentally qualified. However, seismic criteria are not included in qualification regarding mounting and location for that portion of the trip system located within nonseismic Category I structures.

Evaluations indicate that the functional performance of the protection system would not be degraded by credible electrical faults such as opens and shorts in the circuits associated with reactor trip or the generation of the P-7 interlock. The solid state protection system cabinets are provided with fuse protection for the turbine stop valve reactor trip cabling in the Turbine Building to preclude degradation of required solid state protection system functions. Faults on the Turbine Building cables going to the oil

pressure low transmitters will not degrade the protection system as they are isolated from the protection system by the process instrumentation (Foxboro) cabinets in the main control room. Loss of signal caused by open circuits would produce either a partial or full reactor trip. Faults on the first stage turbine pressure circuits would result in upscale, conservative output for open circuits and a sustained current, limited by circuit resistance, for short circuits. Multiple failures imposed on these redundant circuits could potentially disable the P-13 interlock. In this event, the nuclear instrumentation power range signals would provide the P-7 safety interlock. Refer to functional diagram, Sheet 4 of Figure 7.2-1. The sensors for the P-13 interlock are seismically qualified.

Evaluations provided in Section 7.6.1 for the trip fluid pressure transmitter loops indicate that credible electrical faults would not degrade the functional performance of the safety-related BOP instrumentation.

In addition, the following measures will be taken to ensure the integrity of the cabling to the reactor protection system (RPS):

1. Inputs from the turbine steam stop valves will originate from four separate limit switches (one per valve), each of which is dedicated to providing an input to one channel of the RPS. Cables carrying these signals will be routed in individual conduits. The four circuits will be separated from one another, from non-Class 1E circuits, and identified according to the criteria imposed on Class 1E circuits from their source up to their terminations with the RPS cabinets.

2. Inputs from the emergency trip oil pressure and P-13 interlock instrumentation will be routed in a similar manner as are the turbine stop valve inputs.

   The logic for this trip is shown on Figure 7.2-1 (Sheet 16).

g. Safety injection signal actuation trip

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

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

h. Manual trip

The manual trip consists of two switches with two outputs on each switch. One output is used to actuate the train A reactor trip breaker; the other

output actuates the train B reactor trip breaker. Operating a manual trip switch removes the voltage from the undervoltage trip coil and energizes the shunt trip coil of each breaker.

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

7.2.1.1.3 Reactor Trip System Interlocks

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

a. Power escalation permissives

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

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

The intermediate range level trip and power range (low setpoint) trip can only be blocked after satisfactory operation and permissive information are obtained from two out of four power range channels. Four individual blocking switches are provided so that the low range power range trip and intermediate range trip can be independently blocked (one switch for each train). These trips are automatically reactivated when any three out of the four power range channels are below the permissive (P-10) setpoint, thus ensuring automatic activation to more restrictive trip protection. The development of permissives P-6 and P-10 is shown on Figure 7.2-1 (Sheet 4). All of the permissives are digital; they are derived from analog signals in the nuclear power range and intermediate range channels.

b. Blocks of reactor trips at low power

Interlock P-7 blocks a reactor trip at low power (below 10 percent of full power) on a low reactor coolant flow in more than one loop, reactor coolant

pump undervoltage, reactor coolant pump underfrequency, pressurizer low pressure or pressurizer high water level. See Figure 7.2-1 (Sheets 5 and 6) for permissive applications. The P-7 interlock is derived from three out of four power range neutron flux signals below the setpoint in coincidence with two out of two turbine impulse chamber pressure signals below the setpoint (low plant load). See Figure 7.2-1 (Sheets 4 and 16) for the derivation of P-7.

The P-8 interlock blocks a reactor trip when the plant is below 48 percent of full power, on a low reactor coolant flow in any one loop.

The block action occurs when three out of four neutron flux power range signals are below the setpoint. Thus, below the P-8 setpoint, the reactor has the capability to operate with one inactive loop and trip will not occur until two loops are indicating low flow. See Figure 7.2-1 (Sheet 4) for derivation of P-8 and Sheet 5 for applicable logic.

Interlock P-9 blocks a reactor trip following a turbine trip below 50 percent power. See Figure 7.2-1 (Sheet 16) for the implementation of the P-9 interlock and Sheet 4 for the derivation of P-9.

7.2.1.1.4 Coolant Temperature Sensor Arrangement

One hot leg and one cold leg temperature reading are provided from each coolant loop to use for protection. Narrow range, thermowell-mounted Resistance Temperature Detectors (RTDs) are provided for each coolant loop. In the hot legs, sampling scoops are used because the flow is stratified. That is, the fluid temperature is not uniform over a cross section of the hot leg. One dual element RTD is mounted in a thermowell in each of the three sampling scoops associated with each hot leg. The scoops extend into the flow stream at locations 120° apart in the cross sectional plane. Each scoop has five orifices which sample the hot leg flow along the leading edge of the scoop. Outlet ports are provided in the scoops to direct the sampled fluid past the sensing element of the RTDs. One of each of the RTD's dual elements is used while the other is an installed spare. Three readings from each hot leg are averaged to provide a hot leg reading for that loop.

One dual element RTD is mounted in a thermowell associated with each cold leg. No flow sampling is needed because coolant flow is well mixed by the reactor coolant pumps. As is the case with the hot leg, one element is used while the other is an installed spare.

Certain control signals are derived from individual protection channels through isolation cards. The isolation cards are classified as a part of the protection system. The rod control system uses the auctioneered (high) value of four isolated T-AVG signals.

The RTDs are a fast response design which conforms to the applicable IEEE standards and 10 CFR 50.49 requirements.

7.2.1.1.5 Pressurizer Water Level Reference Leg Arrangement

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

7.2.1.1.6 Analog System

The analog system consists of two instrumentation systems - the process instrumentation system and the nuclear instrumentation system.

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

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

Various types of neutron detectors, with appropriate solid state electronic circuitry, are used to monitor the leakage neutron flux from subcritical conditions to 120 percent of full power. The neutron flux covers a wide range between these extremes. Therefore, monitoring with several ranges of instrumentation is necessary.

The lowest range ("source" range) covers six decades of leakage neutron flux. The lowest observed count rate depends on the strength of the neutron sources in the core and the core multiplication associated with the shutdown reactivity. This is generally

greater than two counts per second. The next range ("intermediate" range) covers eight decades. Detectors and instrumentation are chosen to provide overlap between the higher portion of the source range and the lower portion of the intermediate range. The highest range of instrumentation ("power" range) covers approximately two decades of the total instrumentation range. This is a linear range that overlaps with the higher portion of the intermediate range.

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

A separate neutron flux monitoring system is discussed in Section 7.6.14 and Table 7A-3, Data Sheet 1.1 (SE-NE-60,61).

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

7.2.1.1.7 Solid State Logic Protection System

The solid state logic protection system takes binary inputs (voltage/no voltage) from the process and nuclear instrument channels corresponding to conditions (normal/abnormal) of plant parameters. The system combines these signals in the required logic combination and generates a trip signal (no voltage) to the undervoltage coils of the reactor trip circuit breakers when the necessary combination of signals occur. This trip signal also de-energizes the auto shunt trip relay which, in turn, closes a contact that energizes the shunt trip coil. The system also provides annunciator, status light, and computer input signals which indicate the condition of bistable input signals, partial trip and full trip functions, and the status of the various blocking, permissive, and actuation functions. In addition, the system includes means for semiautomatic testing of the logic circuits. See References 3, 8, 9, and 10 for additional background information.

7.2.1.1.8 Isolation Amplifiers

In certain applications, control signals are derived from individual protection channels through isolation amplifiers contained in the protection channel, as permitted by IEEE Standard 279-1971.

In all of these cases, analog signals derived from protection channels for nonprotective functions are obtained through isolation amplifiers located in the analog protection racks.

By definition, nonprotective functions include those signals used for control, remote process indication, and computer monitoring. Refer to Section 7.1.2.2.1 for a discussion of electrical separation of control and protection functions.

7.2.1.1.9 Energy Supply and Environmental Variations

The energy supply for the reactor trip system, including the voltage and frequency variations, is described in Section 7.6 and Chapter 8.0. The environmental variations, throughout which the system will perform, are given in Sections 3.11(B), 3.11(N) and Chapter 8.0.

7.2.1.1.10 Setpoints

The setpoints that require trip action are given in the Technical Specifications. A detailed discussion on setpoints is found in Section 7.3.8.1.2.7.

7.2.1.1.11 Seismic Design

The seismic design considerations for the reactor trip system are given in Section 3.10(N). This design meets the requirements of GDC-2 (refer to Section 3.1).

7.2.1.2 Design Bases Information

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

7.2.1.2.1 Generating Station Conditions

The following are the generating station conditions requiring reactor trip.

a. DNBR approaching the applicable DNBR limit value (see Chapter 4).

b. Linear power density (kilowatts per foot) approaching rated value for Condition II events (see Chapter 4.0 for fuel design limits).

c. Reactor coolant system overpressure creating stresses approaching the limits specified in Chapter 5.0.

7.2.1.2.2 Generating Station Variables

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

a. Neutron flux

b. Reactor coolant temperature

c. Reactor coolant system pressure (pressurizer pressure)

d. Pressurizer water level

e. Reactor coolant flow

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

g. Steam generator water level (See Reference 5)

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

7.2.1.2.3 Spatially Dependent Variables

The only spatially dependent variable is the reactor coolant temperature. See Section 7.3.8.1.2 for a discussion of this spatial dependence.

7.2.1.2.4 Limits, Margins, and Setpoints

The parameter values that will require reactor trip are given in Chapter 15.0 and the Callaway Technical Specifications. The accident analyses in Chapter 15.0 demonstrate that the setpoints used in the Callaway Technical Specifications are conservative.

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

a. Minimum DNBR = applicable DNBR limit value (see Chapter 4).

b. Maximum system pressure = 2,750 psia

c. Fuel rod maximum linear power for determination of protection setpoints = 18.0 kW/ft

The accident analyses described in Section 15.4 demonstrate that the functional requirements specified for the reactor trip system are adequate to meet the above considerations, even assuming the conservative, adverse combinations of instrument errors (refer to Table 15.0-4). A discussion of the safety limits associated with the reactor core and reactor coolant system, plus the limiting safety system setpoints, are presented in the Callaway Technical Specifications.

7.2.1.2.5 Abnormal Events

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

a. Earthquakes (see Chapters 2.0 and 3.0)

b. Fire (see Section 9.5.1)

c. Explosion - hydrogen buildup inside containment (see Section 6.2)

d. Missiles (see Section 3.5)

e. Flood (see Chapters 2.0 and 3.0)

f. Wind and tornadoes (see Section 3.3)

The reactor trip system fulfills the requirements of IEEE Standard 279-1971 to provide automatic protection and to provide initiating signals to mitigate the consequences of faulted conditions. The reactor trip system is protected from fires, explosions, floods, winds, and tornadoes (see each item above).

7.2.1.2.6 Minimum Performance Requirements

a. Reactor trip system response times

   Typical time delays in generating the reactor trip signal are tabulated in Table 7.2-3. See Section 7.1.2.6.2 for a discussion of periodic response time verification capabilities.

b. Reactor trip accuracies

   Typical reactor trip accuracies are tabulated in Table 7.2-3. An additional discussion on accuracy is found in Section 7.3.8.1.2.7.

c. Protection system ranges

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

7.2.1.3 Final Systems Drawings

Functional block diagrams, electrical elementaries, and other drawings required to assure electrical separation and perform a safety review are provided in the Safety-Related Drawing Package (refer to Section 1.7).

7.2.2 ANALYSES

7.2.2.1 Failure Mode and Effects Analyses

An analysis of the reactor trip system has been performed. Results of this study and a fault tree analysis are presented in Reference 4. Replacement solid state protection system circuit boards were analyzed and tested to determine impact to the Failure Modes and Effects Analyses. The replacement circuit boards will continue to perform as described in Reference 4, but additional board level redundancies will prevent certain sub-component failures from resulting in overall board failure as described in References 8, 9, and 10 for the three circuit boards associated with active safety functions.

7.2.2.2 Evaluation of Design Limits

While most setpoints used in the reactor protection system are fixed, there are variable setpoints, most notably the overtemperature ΔT and overpower ΔT setpoints. Additionally, for steam generator low-low level reactor trip, the Environmental Allowance Modifier (EAM) circuitry allows for two setpoints, one for a normal containment environment and another enabled when an adverse environment is detected. All set-points in the reactor trip system have been selected on the basis of engineering design or safety studies. The capability of the reactor trip system to prevent loss of integrity of the fuel cladding and/or reactor coolant system pressure boundary during Condition II and III transients is demonstrated in Chapter 15.0. Accident analyses are carried out using those setpoints determined from results of the engineering design studies. Setpoint limits are presented in the Callaway Technical Specifications. A discussion of the intent for each of the various reactor trips and the accident analyses (where appropriate) which utilize this trip are presented below. It should be noted that the selected trip setpoints provide for a margin to allow for uncertainties and instrument errors. The design meets the requirements of GDC-10 and 20 (refer to Section 3.1).

7.2.2.2.1 Trip Setpoint Discussion

The DNBR existing at any point in the core for a given core design can be determined as a function of the core inlet temperature, power output, operating pressure, and flow. Core safety limits in terms of the applicable DNBR limit for the hot channel can be developed as a function of core ΔT, T_{avg} and pressure for the thermal design flow, as illustrated by the solid lines in Figure 15.0-1. The dashed lines indicate the maximum permissable setpoint (ΔT) as a function of T_{avg} and pressure for the overtemperature and overpower reactor trip. Actual setpoint constants in the equation representing the dashed lines are as given in the Callaway Technical Specifications. These values are

conservative to allow for instrument errors. The design meets the requirements of GDC-10, 15, 20, and 29 (refer to Section 3.1).

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

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

The design meets the requirements of GDC-21 (refer to Section 3.1).

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

Analyses of the results of Condition I, II, III, and IV events, including considerations of instrumentation installed to mitigate their consequences, are presented in Chapter 15.0. The instrumentation installed to mitigate the consequences of load rejection and turbine trip is given in Section 7.4.

7.2.2.2.2 Reactor Coolant Flow Measurement

The elbow taps used on each loop in the primary coolant system are instrument devices that indicate the status of the reactor coolant flow. The basic function of this device is to

provide information as to whether or not a reduction in flow has occurred. The correlation between flow and elbow tap signal is given by the following equation:

$$\frac{\Delta P}{\Delta P_o} \propto \left(\frac{W}{W_o}\right)^2$$

where ΔP_o is the pressure differential at the reference flow W_o and ΔP is the pressure differential at the corresponding flow, W. The full flow reference point is established during initial plant startup. The low flow trip point is then established at 90% of full flow. The expected absolute accuracy of the channel is within ± 10 percent of full flow, and field results have shown the repeatability of the trip point to be within ± 1 percent.

7.2.2.2.3 Evaluation of Compliance to Applicable Codes and Standards

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

a. General functional requirement

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

b. Single failure criterion

   The protection system is designed to provide two, three, or four instrumentation channels for each protective function and two logic train circuits. These redundant channels and trains are electrically isolated and physically separated. Thus, any single failure within a channel or train will not prevent protective action at the system level when required. Loss of input power to a channel or logic train, the most likely mode of failure, will result in a signal calling for a trip. This design meets the requirements of GDC-23 (refer to Section 3.1).

   To prevent the occurrence of common mode failures, such additional measures as functional diversity, physical separation, and testing, as well as administrative control during design, production, installation, and operation, are employed, as discussed in References 4, 8, 9, and 10. The design meets the requirements of GDC-21 and 22 (refer to Section 3.1).

c. Quality of components and modules

For a discussion on the quality of the components and modules used in the reactor trip system, refer to Chapter 17.0. The quality assurance applied conforms to GDC-1 (refer to Section 3.1).

d. Equipment qualification

For a discussion of the type tests made to verify the performance requirements, refer to Section 3.11(N). The test results demonstrate that the design meets the requirements of GDC-4 (refer to Section 3.1).

e. Channel integrity

Protection system channels required to operate in accident conditions maintain necessary functional capability under extremes of conditions relating to environment, energy supply, malfunctions, and accidents. The energy supply for the reactor trip system is described in Section 7.6 and Chapter 8.0. The environmental variations throughout which the system will perform are given in Section 3.11(N).

f. Independence

Channel independence is carried throughout the system, extending from the sensor through to the devices actuating the protective function. Physical separation is used to achieve separation of redundant transmitters. Separation of wiring is achieved using separate wireways, cable trays, conduit runs, and containment penetrations for each redundant channel. Redundant analog equipment is separated by locating modules in different protection cabinets. Each redundant protection channel set is energized from a separate ac power feed. This design meets the requirements of GDC-21 (refer to Section 3.1).

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

The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. Generally, two or more diverse protection functions would terminate an accident before limits are exceeded. This design meets the requirement of GDC-22 (refer to Section 3.1).

g. Control and protection system interaction

The protection system is designed to be independent of the control system. In certain applications, the control signals and other nonprotective functions are derived from individual protection channels through isolation amplifiers, as described in Section 7.2.1.1.8. The isolation amplifiers are classified as part of the protection system and are located in the analog protection racks. Nonprotective functions include those signals used for control, remote process indication, and computer monitoring. The isolation amplifiers are designed such that a short circuit, open circuit, or the application of credible fault voltages from within the cabinets on the isolated output portion of the circuit (i.e., the nonprotective side of the circuit) will not affect the input (protective) side of the circuit. The signals obtained through the isolation amplifiers are never returned to the protective racks. This design meets the requirements of GDC-24 and Section 4.7 of IEEE Standard 279-1971 (refer to Section 3.1).

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

h. Derivation of system inputs

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

i. Capability for sensor checks

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

j. Capability for testing

The reactor trip system is capable of being tested during power operation. Where only parts of the system are tested at any one time, the testing sequence provides the necessary overlap between the parts to ensure complete system operation. The testing capabilities are in conformance with Regulatory Guide 1.22, as discussed in Section 7.1.2.5.2.

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation without initiating a protective action, unless a trip condition actually exists. This is because of the coincidence logic required for reactor trip. These

tests may be performed at any plant power from cold shutdown to full power. Before starting any of these tests with the plant at power, all redundant reactor trip channels associated with the function to be tested must be in the normal (untripped) mode in order to avoid spurious trips. Setpoints are administratively controlled.

Analog Channel Tests

Analog channel testing is performed at the analog instrumentation rack set by individually introducing dummy input signals into the instrumentation channels and observing the tripping of the appropriate output bistables. Process analog output to the logic circuitry is interrupted during individual channel tests by test switches which, when thrown, place the Environmental Allowance Modifier (EAM) function into a conservative state, deenergize the associated logic inputs and insert a proving lamp in the bistable outputs. Interruption of a bistable output to the logic circuitry for any cause (test, maintenance purposes, or removed from service) will cause that portion of the logic to be actuated (partial trip), accompanied by a partial trip alarm and channel status light actuation in the control room. Each channel contains those switches, test points, etc. necessary to test the channel. See References 1, 2, and 5 (as clarified) for additional background information.

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

1. T_{avg} and ΔT protection channel testing
2. Pressurizer pressure protection channel testing
3. Pressurizer water level protection channel testing
4. Steam generator water level protection channel testing
5. Reactor coolant low flow, underfrequency, and undervoltage protection channels
6. Steam line pressure protection channels
7. Containment pressure

Nuclear Instrumentation Channel Tests

The power range channels of the nuclear instrumentation system are tested by superimposing a test signal on the actual detector signal being received by the channel at the time of testing. The output of the bistable is

not placed in a tripped condition prior to testing. Also, since the power range channel logic is two out of four, bypass of this reactor trip function is not required.

To test a power range channel, a "TEST-OPERATE" switch is provided to require deliberate operator action. Operation of this switch will initiate the "CHANNEL TEST" annunciator in the control room. Bistable operation is tested by increasing the test signal to its trip setpoint and verifying bistable relay operation by control board annunciator and trip status lights. It should be noted that a valid trip signal would cause the channel under test to trip at a lower actual reactor power level.

A reactor trip would occur when a second bistable trips. No provisions have been made in the channel test circuit for reducing the channel signal level below that signal being received from the nuclear instrumentation system detector.

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

Periodic tests of all three ranges of the nuclear instrumentation system are performed while at plant shutdown or while the reactor is at power.

Any deviations noted during the performance of these tests are investigated and corrected in accordance with the established calibration and trouble shooting procedures provided in the plant technical manual for the nuclear instrumentation system. Control and protection trip settings are administratively controlled.

In addition to the above tests, incore/excore calibrations of the power range channels are conducted while the reactor is at power. Also, 18-month calibrations of the source range, intermediate range, and power range channels are permitted to be conducted at power. During the incore/excore calibration adjustments and during the 18-month calibrations at power, it is permitted to disconnect the detector and high voltage power supply cables for testing.

For additional background information on the nuclear instrumentation system, see Reference 2.

Solid State Logic Testing

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

A direct reactor trip resulting from undervoltage or underfrequency on the reactor coolant pump busses is provided, as discussed in Section 7.2.1.1.2 and shown on Figure 7.2-1 (Sheet 5). The logic for these trips is capable of being tested during power operation. When parts of the trip are being tested, the sequence is such that an overlap is provided between parts so that a complete logic test is provided. Thus complete testing of the RTS is possible.

This design complies with the testing requirements of IEEE Standard 279-1971 and IEEE Standard 338-1971 discussed in Section 7.1.2.6.2. For additional details, see References 3, 8, 9, and 10.

The permissive and block interlocks associated with the reactor trip system and engineered safety feature actuation system are given on Tables 7.2-2 and 7.3-15 and designated protection or "P" interlocks. As a part of the protection system, these interlocks are designed to meet the testing requirements of IEEE Standard 279-1971 and IEEE Standard 338-1971.

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

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

1. Check of input relays

   During testing of the process instrumentation system and nuclear instrumentation system channels, each channel bistable is placed in a trip mode, causing one input relay in train A and one in train B to deenergize. A contact of each relay is connected to a universal logic printed circuit card. This card performs both the reactor trip and monitoring functions. Each reactor trip input relay contact causes a status lamp and an annunciator on the control board to operate. Either the train A or train B input relay operation will light the status lamp and annunciator.

   Each train contains a multiplexing test switch. At the start of a process or nuclear instrumentation system test, this switch (in either train) is placed in the A + B position.

   The A + B position alternately allows information to be transmitted from the two trains to the control board. A steady status lamp and annunciator indicates that input relays in both trains have been deenergized. A flashing lamp means that the input relays in the two trains did not both deenergize. Contact inputs to the logic protection system, such as reactor coolant pump bus underfrequency relays, operate input relays which are tested by operating the remote contacts as described above and using the same type of indications as those provided for bistable input relays.

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

2. Check of logic matrices

   Logic matrices are checked, one train at a time. Input relays are not operated during this portion of the test. Reactor trips from the train being tested are inhibited with the use of the input error inhibit switch

on the semiautomatic test panel in the train. At the completion of the logic matrix tests, one bistable in each channel of process instrumentation or nuclear instrumentation is tripped to check closure of the input error inhibit switch contacts.

The logic test scheme uses pulse techniques to check the coincidence logic. All possible trip and nontrip combinations are checked. Pulses from the tester are applied to the inputs of the universal logic card at the same terminals that connect to the input relay contacts. Thus there is an overlap between the input relay check and the logic matrix check. Pulses are fed back from the reactor trip breaker undervoltage coil and auto shunt trip relay to the tester. The pulses are of such short duration that the reactor trip breaker undervoltage trip attachment (UVTA) trip lever and shunt trip attachment (STA) armature cannot respond mechanically.

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

3. General warning alarm reactor trip

Each of the two trains of the solid state protection system is continuously monitored by the general warning alarm reactor trip subsystem. The warning circuits are actuated if undesirable train conditions are set up by improper alignment of testing systems, circuit malfunction or failure, etc., as listed below. A trouble condition in a logic train is indicated in the control room.

However, if any of the conditions exist in both trains at the same time, the general warning alarm circuits will automatically trip the reactor.

a. Loss of either of two 48 volt dc or either of two 15 volt dc power supplies.

b. Printed circuit card improperly inserted.

c. Input error inhibit switch in the INHIBIT position.

d. Slave relay tester mode selector in TEST position.

e. Multiplexing selector switch in INHIBIT position.

f. Loss of ac power in relay cabinets.

g. Opposite train bypass breaker racked in and closed.

h. Permissive or memory test switch not in OFF position.

i. Logic function test switch not in OFF position.

The testing capability meets the requirements of GDC-21 (refer to Section 3.1).

Testing of Reactor Trip Breakers

Normally, reactor trip breakers 52/RTA and 52/RTB are in service, and bypass breakers 52/BYA and 52/BYB are withdrawn (out of service). In testing the protection logic, pulse techniques are used to avoid tripping the reactor trip breakers, thereby eliminating the need to bypass them during this testing. The following procedure describes the method used for testing the trip breakers:

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

2. Rack in and close 52/BYA.

3. Manually trip 52/RTA through a protection system logic matrix while at the same time depressing the auto shunt trip block push-button switch on the auto shunt trip panel. This verifies the operation of the UVTA when the breaker trips.

4. Release the auto shunt trip block push-button switch. After reclosing 52/RTA, trip it again by depressing the auto shunt trip test push-button switch on the auto shunt trip panel. This verifies the operation of the STA when the breaker trips.

5. Reclose 52/RTA.

6. Open and rack out 52/BYA.

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

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

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

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

Auxiliary switch contacts (P-4) of the reactor trip breakers which initiate protective functions can be tested on-line to verify proper operation. Testing is accomplished using selector switches and voltmeters mounted on the front panels of the reactor trip switchgear cabinets.

The complete reactor trip system is normally required to be in service. However, to permit on-line testing of the various protection channels or to permit continued operation in the event of a subsystem instrumentation channel failure, the Callaway Technical Specifications define the required number of operable channels. The Callaway Technical Specifications also define the required actions in the event that the channel operability requirements cannot be met.

k. Channel bypass or removal from operation

The protection system is designed to permit periodic testing of the analog channel portion of the reactor trip system during reactor power operation without initiating a protective action, unless a trip condition actually exists. This is because of the coincidence logic required for reactor trip. Additional information is given in Section 7.2.1.1.2.

l. Operating bypasses

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

m. Indication of bypasses

Bypass indication is addressed in Table 7.5-3.

n. Access to means for bypassing

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

o. Multiple setpoints

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

p. Completion of protective action

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

q. Manual initiation

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

r. Access

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

s. Identification of protective actions

Protective channel identification is discussed in Section 7.1.2.3. Indication is discussed in item t below.

t. Information readout

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

range currents (top detector, bottom detector, algebraic difference, and average of bottom and top detector currents).

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

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

u. System repair

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

7.2.2.3 Specific Control and Protection Interactions

7.2.2.3.1 Neutron Flux

Four power range neutron flux channels are provided for overpower protection. An isolated auctioneered high signal is derived by auctioneering the four channels for automatic rod control (automatic rod insertion only - automatic rod withdrawal no longer available). If any channel fails in such a way as to produce a low output, that channel is incapable of proper overpower protection but will not cause control rod movement because of the auctioneer. Two-out-of-four overpower trip logic will ensure an overpower trip if needed, even with an independent failure in another channel.

In addition, channel deviation signals in the nuclear instrumentation system (NIS), as discussed in Section 7.7.1.3.1, will give an alarm if any neutron flux channel deviates significantly from the average of the flux signals. Also, the protection system will respond only to rapid changes in indicated neutron flux; slow changes or drifts are compensated by the reactor control system (See Section 7.7.1.1). Finally, an overpower signal (See Section 7.7.1.4) from any neutron flux intermediate or power range channel will block any rod withdrawal. The setpoints for these rod stops are below the reactor trip setpoints. The intermediate range rod stop (C-1) is blocked as a part of a controlled startup.

7.2.2.3.2 Coolant Temperature

The accuracy of the narrow range resistance temperature detector (RTD) temperature measurements is demonstrated during plant startup tests by comparing temperature measurements from these RTDs with one another as well as with the temperature measurements obtained from the wide range RTDs. The comparisons are done with the reactor coolant system in an isothermal condition. The linearity of the ΔT measurements

obtained from the hot leg and cold leg RTDs as a function of plant power is also checked during plant startup tests. The absolute value of ΔT versus plant power is not important, per se, as far as reactor protection is concerned. Reactor trip system setpoints are based upon percentages of the indicated ΔT at nominal full power rather than on absolute values of ΔT. This is done to account for loop differences which are inherent. The percent ΔT scheme is relative, not absolute, and therefore provides better protective action without the requirement of absolute accuracy. For this reason, the linearity of the ΔT signals as a function of power is of importance rather than the absolute values of the ΔT. As part of the plant startup tests, the RTD signals will be compared with the core exit thermocouple signals.

Reactor control is based upon signals derived from protection system channels after isolation by isolation amplifiers such that no feedback effect can perturb the protection channels. Since control is based on the average temperature of the loop with the highest temperature, the control rods are always moved based upon the most pessimistic temperature measurement with respect to margins to DNB. A spurious low average temperature measurement from any loop temperature control channel will cause no control action. A spurious high average temperature measurement will cause rod insertion (safe direction) when operating in the automatic rod control mode.

T-avg and ΔT channel deviation signals in the control system will give an alarm if any temperature channel deviates significantly from the auctioneered (highest) value. Rod withdrawal blocks and turbine runbacks (power demand reduction) will also occur if any two out of the four overtemperature or overpower ΔT channels indicate an adverse condition.

7.2.2.3.3 Pressurizer Pressure

The pressurizer pressure protection channel signals are used for high and low pressure protection and as inputs to the overtemperature ΔT trip protection function. Isolated output signals from these channels are used for pressure control. These are used to control pressurizer spray and heaters. Safety-related automatic actuation signals are also used to actuate the power-operated relief valves. Pressurizer pressure is sensed by fast response pressure transmitters.

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

Overpressure protection is based upon the positive surge of the reactor coolant produced as a result of turbine trip under full load, assuming that the core continues to produce full power. The self-actuated safety valves, with a nominal set pressure of 2460 psig, are sized on the basis of steam flow from the pressurizer to accommodate this surge at a pressure of 2,500 psia and an accumulation of 3 percent. No credit is taken for the relief capability provided by the power-operated relief valves during this surge.

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

Redundancy is not compromised by having a shared tap (see Section 7.2.1.1.2) since the logic for this trip is two out of four. If the shared tap is plugged, the affected channels will remain static. If the impulse line bursts, the indicated pressure will drop to zero. In either case, the fault is easily detectable, and the protective function remains operable.

7.2.2.3.4 Pressurizer Water Level

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

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

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

7.2.2.3.5 Steam Generator Water Level

The basic function of the reactor protection circuits associated with low-low steam generator water level is to preserve the steam generator heat sink for removal of long term residual heat. Should a complete loss of feedwater occur, the reactor would be tripped on low-low steam generator water level. In addition, redundant auxiliary feedwater pumps are provided to supply feedwater to maintain residual heat removal capability after trip. This reactor trip acts before the steam generators are dry. This reduces the required capacity, increases the time interval before auxiliary feedwater pumps are required, and minimizes the thermal transient on the reactor coolant system and steam generators.

Therefore, a low-low steam generator water level reactor trip circuit is provided for each steam generator to ensure that sufficient initial thermal capacity is available in the steam generator at the start of the transient. Of the two available low-low level setpoints, one corresponding to an adverse and one, a normal containment environment, the Environmental Allowance Modifier (EAM) enables the appropriate setpoint. This trip is

actuated on two-out-of-four low-low water level signals occurring in any steam generator (see Section 7.2.1.1.2 and Reference 5, as clarified). Two-out-of-four low-low steam generator water level trip logic ensures a reactor trip, if needed, even with an independent failure in another channel used for control and when degraded by an additional second postulated random failure.

A spurious low flow signal from the two feedwater flow channels, which are averaged, would cause an increase in feedwater flow. A spurious low feedwater flow signal would indicate a steam flow/feed flow mismatch and create an error signal causing the feedwater control system to compensate for what is perceived to be insufficient feedwater flow. In addition, a spurious high steam flow signal from the two steam flow channels, which are averaged, would also indicate a steam flow/feed flow mismatch and create an error signal causing the feedwater control system to increase feedwater flow to match the perceived high steam flow demand. The mismatch between steam flow and feedwater flow produced by the spurious signal would actuate alarms to alert the operator of the situation in time for manual correction (see Figure 7.2-1, sheets 13, 14). If the condition continues, a two-out-of-four high-high steam generator water level signal in any loop, independent of the indicated feedwater flow, will cause feedwater isolation and trip the turbine. The turbine trip will result in a subsequent reactor trip if power is above the P-9 setpoint. The high-high steam generator water level trip is an equipment protective trip preventing excessive moisture carryover which could damage the turbine blading.

In addition, the three-element feedwater controller incorporates reset action on the level error signal, such that with expected controller settings a rapid increase or decrease in the flow signal would cause only a small change in level before the controller would compensate for the level error. A slow change in the feedwater signal would have no effect at all. A spurious low or high steam flow signal would have the same effect as high or low feedwater signal, discussed above. A spurious high steam generator water level signal from the average of two level channels will tend to close the feedwater control valve. A spurious low steam generator water level signal from the average of two level channels will tend to open the feedwater control valve. Before a reactor trip would occur, two out of four channels in a loop would have to indicate a low-low water level. Any slow drift in the water level signal will permit the operator to respond to the level alarms and take corrective action.

Automatic protection is provided in case the spurious high level reduces feedwater flow sufficiently to cause low-low level in the steam generator. Automatic protection is also provided in case the spurious low level signal increases feedwater flow sufficiently to cause high level in the steam generator. A turbine trip and feedwater isolation would occur on two-out-of-four high-high steam generator water level in any loop.

7.2.2.4 Additional Postulated Accidents

Loss of plant instrument air or loss of component cooling water is discussed in Section 7.3.8.2. Load rejection and turbine trip are discussed in further detail in Section 7.7.

The control interlocks, called rod stops, that are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal are discussed in Section 7.7.1.4 and listed in Table 7.7-1. Excessively high power operation (which is prevented by blocking of manual rod withdrawal), if allowed to continue, might lead to a safety limit (as given in the Callaway Technical Specifications) being reached. Before such a limit is reached, protection will be available from the reactor trip system. At the power levels of the rod block setpoints, safety limits have not been reached; and, therefore, these rod withdrawal stops do not come under the scope of safety-related systems, and are considered as control systems.

7.2.3 TESTS AND INSPECTIONS

The reactor trip system meets the testing requirements of IEEE Standard 338-1971, as discussed in Section 7.1.2.6.2. The testability of the system is discussed in Section 7.2.2.2.3. The initial test intervals are specified in the Callaway Technical Specifications. Written test procedures and documentation, conforming to the requirement of IEEE Standard 338-1971, are available for audit by responsible personnel. Periodic testing complies with Regulatory Guide 1.22, as discussed in Sections 7.1.2.5.2 and 7.2.2.2.3.

The following exceptions are taken to the surveillance test methodology defined in Section 3.6.2 of WCAP 11883 (Reference 5) regarding the SG water level low-low trip:

1. Each level channel is tested one-at-a-time during the level channel testing with zero time delay as described in the WCAP.

2. The TTD function and timers discussed in Reference 5 are no longer applicable to Callaway.

3. Section 3.6.2.2. is titled OUTAGE TESTING. The PROM logic modules and the EAM testing described under this section may be performed on-line and not restricted to performance during outages.

7.2.4 REFERENCES

1. Reid, J. B., "Process Instrumentation for Westinghouse Nuclear Steam Supply Systems (4 Loop Plant Using WCID 7300 Series Process Instrumentation)," WCAP-7913, January 1973. (Additional background information only.)

2. Lipchak, J. B., "Nuclear Instrumentation System," WCAP-8255, January 1974. (Additional background information only.)

3. Katz, D. N., "Solid State Logic Protection System Description," WCAP-7488-L (Proprietary), January, 1971 and WCAP-7672 (Non-Proprietary), June 1971. (Additional background information only.)

4. Gangloff, W. C. and Loftus, W. D., "An Evaluation of Solid State Logic Reactor Protection in Anticipated Transients," WCAP-7706-L (Proprietary) and WCAP-7706 (Non-Proprietary), July 1971.

5. Leach, C. E., Gongaware, B. L., Turley, C. R., Erin, L. E., Miranda, S., " Implementation of the Steam Generator Low-Low Level Reactor Trip Time Delay and Environmental Allowance Modifier in the Callaway Plant", WCAP-11883 (Proprietary) and WCAP-11884 (Non-Proprietary), August, 1988 submitted via ULNRC-1822 dated 8-30-88 and approved via Amendment 43 to Facility Operating License NPF-30 dated 4-14-89.

   The following exceptions are taken to the surveillance test methodology defined in Section 3.6.2 of WCAP 11883:

   1. Each level channel is tested one-at-a-time during the level channel testing with zero time delay as described in the WCAP.

   2. The TTD function and timers discussed in Reference 5 are no longer applicable to Callaway..

   3. Section 3.6.2.2 is titled OUTAGE TESTING. The PROM logic modules and the EAM testing described under this section may be performed on-line and not restricted to performance during outages.

6. Union Electric letters ULNRC-1863 dated 11-18-88, ULNRC-1884 dated 12-28-88, ULNRC-1905 dated 2-7-89, and ULNRC-1913 dated 2-15-89.

7. “Callaway Replacement Steam Generator Program NSSS Engineering Report,” WCAP-16140 (Proprietary), July 2004.

8. Gruber, T. J. and Harbaugh, T. D., “Westinghouse SSPS Universal Logic Board Replacement Summary Report 6D30225G01/G02/G03/G04,” WCAP-16769-P, Revision 2, February, 2011.

9. Harbaugh, T. D. and Hines, E. F., “Westinghouse SSPS Safeguards Driver Board Replacement Summary Report 6D30252G01/G02,” WCAP-16770-P, Revision 0, August, 2008.

10. Gruber, T. J. and Harbaugh, T. D., “Westinghouse SSPS Undervoltage Driver Board Replacement Summary Report 6D30350G01/G02,”WCAP-16771-P, Revision 1, April, 2011.

TABLE 7.2-1 LIST OF REACTOR TRIPS

	Reactor Trip	Coincidence Logic	Protection Interlocks	Comments
1.	Power range high neutron flux	2/4	Manual block of low setting permitted by P-10	High and low setting; manual block and automatic reset of low setting by P-10
2.	Intermediate range high neutron flux	1/2	Manual block permitted by P-10	Manual block and automatic reset by P-10
3.	Source range high neutron flux	1/2	Manual block permitted by P-6; interlocked with P-10	Manual block and automatic reset by P-6; automatic block above P-10
4.	Power range high positive neutron flux rate	2/4	No interlocks	-
5.	Deleted		-	-
6.	Overtemperature ΔT	2/4	No interlocks	-
7.	Overpower ΔT	2/4	No interlocks	-
8.	Pressurizer low pressure	2/4	Interlocked with P-7	Automatic block below P-7
9.	Pressurizer high pressure	2/4	No interlocks	-
10.	Pressurizer high water level	2/3	Interlocked with P-7	Automatic block below P-7
11.	Low reactor coolant flow	2/3 low flow in any loop	Interlocked with P-7 and P-8	Low flow in one loop will cause a reactor trip when above P-8, and a low flow in two loops will cause a reactor trip when above P-7 and below P-8; automatic block below P-7
		1/4 loops	Interlocked with P-8	Automatic block below P-8
		2/4 loops	Interlocked with P-7	Automatic block below P-7
12.	Reactor coolant pump undervoltage	1/2 in both busses	Interlocked with P-7	Low voltage on all busses permitted below P-7 (automatic block below P-7)

TABLE 7.2-1 (Sheet 2)

Reactor Trip	Coincidence Logic	Protection Interlocks	Comments
13. Reactor coolant pump underfrequency	1/2 in both busses	Interlocked with P-7	Underfrequency on one motor in both busses will trip all reactor coolant pump breakers and cause reactor trip; reactor trip automatically blocked below P-7
14. Low-low steam generator water level	2/4 in any loop	No interlocks	Two level setpoints corresponding to normal and adverse containment environments;.
15. Safety injection	Coincident with actuation of safety injection	Interlocked with P-11. (If reactor coolant is less than 1970 psig, P-11 allows manual block)	See Section 7.3 for engineered safety features actuation conditions
16. Turbine (anticipatory trip)			
a. Low trip fluid pressure	2/3	Interlocked with P-9	Automatic block below P-9
b. Turbine stop valve close	4/4	Interlocked with P-9	Automatic block below P-9
17. Manual	1/2	No interlocks	-

TABLE 7.2-2 PROTECTION SYSTEM INTERLOCKS

Designation	Derivation	Function
	I. Power Escalation Permissives	
P-6	Presence of P-6: 1/2 neutron flux (intermediate range) above setpoint	Allows manual block of source range reactor trip and de-energization of the detector high voltage
	Absence of P-6: 2/2 neutron flux (intermediate range) below setpoint	Defeats the block of source range reactor trip and restores detector high voltage
P-10	Presence of P-10: 2/4 neutron flux (power range) above setpoint	Allows manual block of power range (low setpoint) reactor trip
		Allows manual block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Blocks source range reactor trip and de-energizes detector high voltage (back-up for P-6)
	Absence of P-10: 3/4 neutron flux (power range) below setpoint	Defeats the block of power range (low setpoint) reactor trip
		Defeats the block of intermediate range reactor trip and intermediate range rod stops (C-1)
		Input to P-7
P-11	Presence of P-11: 2/3 pressurizer pressure below setpoint	Allows manual block of safety injection actuation on low pressurizer pressure signal
	Absence of P-11: 2/3 pressurizer pressure above setpoint	Defeats manual block of safety injection actuation
		Opens all accumulator isolation valves

TABLE 7.2-2 (Sheet 2)

Designation	Derivation	Function
	II. Blocks of Reactor Trips	
P-7	Absence of P-7: 3/4 neutron flux (power range) below setpoint (absence of P-10) and 2/2 turbine impulse chamber pressure below setpoint (absence of P-13)	Blocks reactor trip on low reactor coolant flow in more than one loop, undervoltage, underfrequency, pressurizer low pressure, and pressurizer high level
P-8	Absence of P-8: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on low reactor coolant flow in a single loop
P-9	Absence of P-9: 3/4 neutron flux (power range) below setpoint	Blocks reactor trip on turbine trip
P-13	Absence of P-13: 2/2 turbine impulse chamber pressure below setpoint	Input to P-7

TABLE 7.2-3 REACTOR TRIP SYSTEM INSTRUMENTATION

	Reactor Trip Signal	Typical Range	Typical Trip Accuracy	Typical Time Response (sec)*
1.	Power range high neutron flux	1 to 120% of full power**	±1% of full power	0.2
2.	Intermediate range high neutron flux	8 decades of neutron flux overlapping source range by 2 decades and including 150% full power (10^{-11} to 10^{-3} amperes)	± 5% of full scale; ± 1% of full scale from 10% to 50% of full power	0.2
3.	Source range high neutron flux	6 decades of neutron flux (1 to 10^6 counts/sec)	± 5% of full scale	0.65
4.	Power range high positive neutron flux rate	+18% of full power	± 5%	0.2
5.	Deleted	-	-	-
6.	Overtemperature ΔT	T_H 530 to 650°F T_C 510 to 630°F T_{AV} 530 to 630°F P_{PRZR} 1,700 to 2,500 psig ΔI(AFD) -50 to +50% power*** $\Delta T_{setpoint}$ 0 to 150% power***	± 3.2°F (±7.2°F for DBEs)	4.0
7.	Overpower ΔT	T_H 530 to 650°F T_C 510 to 630°F T_{AV} 530 to 630°F $\Delta T_{setpoint}$ 0 to 150% power****	± 2.7°F	4.0
8.	Pressurizer low pressure	1,700 to 2,500 psig	± 18 psi (compensated signal) (± 98 psi for DBEs)	0.6
9.	Pressurizer high pressure	1,700 to 2,500 psig	± 18 psi (noncompensated signal) (± 98 psi for DBEs)	0.6
10.	Pressurizer high water level	Entire cylindrical portion of pressurizer (distance between taps)	± 2.25% of span between taps at design temperature and pressure (± 12.25% of span for DBEs)	1.2
11.	Low reactor coolant flow	0 to 120% of rated flow	± 2.75% of ΔP span (± 12.75% of span for DBEs)	0.3
12.	Reactor coolant pump undervoltage	70 to 100 volts #	± 1% of span	1.2

TABLE 7.2-3 (Sheet 2)

Reactor Trip Signal	Typical Range	Typical Trip Accuracy	Typical Time Response (sec)*
13. Reactor coolant pump underfrequency	54 to 60 Hz	± 0.6% of span (± 1% of span for DBEs)	0.3
14. Low-low steam generator narrow range water level	437-587	See Reference 7.	See Reference 7.
15. Turbine trip	-	0.3	0.3

* The overall allowable response time for each reactor trip channel is given in Table 16.3-1. The channel response time value is the elapsed time from when the parameter being sensed by the channel reaches the safety setpoint until either the undervoltage trip coil in the reactor trip breaker is de-energized or the shunt trip coil is energized. The time until the control and shutdown rods are free to fall into the core is an additional portion of the overall response time. It includes the reactor trip breaker response time and the gripper release time.

** Recorder range is 200% of full power during overpower excursions is available if so configured.

*** Indicator range is -30% to +30% power. Signal range for use in f_1 (ΔI) penalty term of OT-ΔT equation is -40% to +40% power at full power. Recorder range is -60% to +60% power. Function generator card scaling is based on -10V to +10V representing -75% to +75% power.

**** ΔT signal range is 0 to 100°F but does not correspond to 0-150% power. 100°F ΔT exceeds 150% power.

#Undervoltage relay span; corresponds to 8400-12000 volts on RCP motor (PA system) busses.

TABLE 7.2-4 REACTOR TRIP CORRELATION

Trip[a]	Accident [b]	Technical Specification [c]
1. Power range high neutron flux trip (low setpoint)	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition (15.4.1)	3.3.1, Table 3.3.1-1, Function 2.b
	Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1) or an Increase in Feedwater Flow (15.1.2)	
	Spectrum of Rod Cluster Control Assembly Ejection Accidents (15.4.8)	
2. Power range high neutron flux trip (high setpoint)	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition (15.4.1)	3.3.1, Table 3.3.1-1 Function 2.a
	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	
	Startup of an Inactive Reactor Coolant Loop at an Incorrect Temperature (15.4.4)	
	Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1) or an Increase in Feedwater Flow (15.1.2)	
	Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant, (Mode 1, 15.4.6)	
	Excessive Increase in Secondary Steam Flow (15.1.3)	
	Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	
	Steam System Piping Failure (15.1.5)	
	Spectrum of Rod Cluster Control Assembly Ejection Accidents (15.4.8)	
3. Intermediate range high neutron flux trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition (15.4.1)	See Note d, 3.3.1, Table 3.3.1-1, Function 4
4. Source range high neutron flux trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical or Low Power Startup Condition (15.4.1)	See Note d, 3.3.1, Table 3.3.1-1, Function 5
	Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant (Mode 2, 15.4.6)	

TABLE 7.2-4 (Sheet 2)

	Trip[a]	Accident [b]	Technical Specification [c]
5.	Power range high positive neutron flux rate trip	Spectrum of Rod Cluster Control Assembly Ejection Accidents (15.4.8)	3.3.1, Table 3.3.1-1, Function 3
		Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	
6.	Deleted	-	-
7.	Overtemperature ΔT trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	3.3.1, Table 3.3.1-1, Function 6
		Chemical and Volume Control System Malfunction that Results in a Decrease in the Boron Concentration in the Reactor Coolant (Mode 1, 15.4.6)	
		Loss of External Electrical Load (15.2.2)	
		Turbine Trip (15.2.3)	
		Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1) or an Increase in Feedwater Flow (15.1.2)	
		Excessive Increase in Secondary Steam Flow (15.1.3)	
		Inadvertent Opening of a Pressurizer Safety or Relief Valve (15.6.1)	
		Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	
		Loss-of-Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary (15.6.5)	
		Steam System Piping Failures (15.1.5)	
		Feedwater System Pipe Break (15.2.8)	
		RCCA Misoperation (Single Rod Withdrawal) (15.4.3)	
		Steam Generator Tube Failure (15.6.3)	
		Loss of Normal Feedwater Flow(15.2.7)	

TABLE 7.2-4 (Sheet 3)

Trip[a]	Accident [b]	Technical Specification [c]
8. Overpower ΔT trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	3.3.1, Table 3.3.1-1, Function 7
	Feedwater System Malfunctions that Result in a Decrease in Feedwater Temperature (15.1.1) or an Increase in Feedwater Flow (15.1.2)	
	Excessive Increase in Secondary Steam FLow (15.1.3)	
	Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	
	Steam System Piping Failures (15.1.5)	
9. Pressurizer low pressure trip	Inadvertent Opening of a Pressurizer Safety or Relief Valve (15.6.1)	3.3.1, Table 3.3.1-1, Function 8.a
	Loss-of-Coolant Accidents Resulting from a Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary (15.6.5)	
	Steam Generator Tube Failure (15.6.3)	
	Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	
	Steam System Piping Failure (15.1.5)	
	Inadvertent Operation of the ECCS during Power Operation (15.5.1)	
10. Pressurizer high pressure trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	3.3.1, Table 3.3.1-1, Function 8.b
	Loss of External Electrical Load (15.2.2)	
	Turbine Trip (15.2.3)	
	Feedwater System Pipe Break (15.2.8)	
	Reactor Coolant Pump Shaft Seizure (Locked Rotor) (15.3.3)	

TABLE 7.2-4 (Sheet 4)

Trip[a]	Accident [b]	Technical Specification [c]
11. Pressurizer high water level trip	Uncontrolled Rod Cluster Control Assembly Bank Withdrawal at Power (15.4.2)	3.3.1, Table 3.3.1-1, Function 9
	Loss of External Electrical Load (15.2.2)	
	Turbine Trip (15.2.3)	
	Feedwater System Pipe Break (15.2.8)	
12. Low reactor coolant flow	Partial Loss of Forced Reactor Coolant Flow (15.3.1)	3.3.1, Table 3.3.1-1, Function 10
	Loss of Non-Emergency AC Power to the Station Auxiliaries (15.2.6)	
	Complete Loss of Forced Reactor Coolant Flow (15.3.2)	
	Reactor Coolant Pump Shaft Seizure (Locked Rotor) (15.3.3)	
	Startup of an Inactive Reactor Coolant Loop at an Incorrect Temperature (15.4.4)	
13. Reactor coolant pump under-voltage voltage trip	Complete Loss of Forced Reactor Coolant Flow (15.3.2)	3.3.1, Table 3.3.1-1, Function 12
14. Reactor coolant pump under-frequency trip	Complete Loss of Forced Reactor Coolant Flow (15.3.2)	3.3.1, Table 3.3.1-1, Function 13
15. Low-low steam generator water level trip	Loss of Normal Feedwater Flow (15.2.7)	3.3.1, Table 3.3.1-1, Function 14
	Feedwater System Malfunction that Results in an Increase in Feedwater Flow (15.1.2)	
	Turbine Trip (15.2.3)	
	Loss of Non-Emergency AC Power to the Station Auxiliaries (15.2.6)	
	Feedwater System Pipe Break (15.2.8)	

TABLE 7.2-4 (Sheet 5)

Trip[a]	Accident [b]	Technical Specification [c]
16. Reactor trip on turbine trip	Loss of External Electrical Load (15.2.2)	3.3.1, Table 3.3.1-1, Function 16 (Technical Specifications include the anticipatory reactor trip on turbine trip; however, this trip function is not directly credited in any Chapter 15 analysis. See Section 15.1.2.)
	Turbine Trip (15.2.3)	
	Loss of Non-Emergency AC Power to the Station Auxiliaries (15.2.6)	
17. Safety injection signal actuation trip	Inadvertent Opening of a Steam Generator Relief or Safety Valve (15.1.4)	See Note e, 3.3.1, Table 3.3.1-1, Function 17
	Steam System Piping Failure (15.1.5)	See Note e
	Feedwater System Pipe Break (15.2.8)	
	Inadvertent Operation of the ECCS during Power Operation (15.5.1)	
	Steam Generator Tube Failure (15.6.3)	
18. Manual trip	Available for all Accidents (Chapter 15.0)	See Note d, 3.3.1, Table 3.3.1-1, Function 1

TABLE 7.2-4 (Sheet 6)

NOTES:

(a) Trips are listed in order of discussion in Section 7.2.

(b) References refer to accident analyses presented in Chapter 15.0.

(c) References refer to the Callaway Technical Specifications.

(d) This trip is not assumed to function in the accident.

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

(1) Trip functions available for a given accident. See Table 15.0-6 and the Chapter 15 text for the specific trip function credited in the analysis of record.

7.3 ENGINEERED SAFETY FEATURE SYSTEMS

The engineered safety feature actuation systems (ESFAS) are comprised of the instrumentation and controls to sense accident situations and initiate the operation of necessary engineered safety features. The occurrence of a limiting fault, such as a loss-of-coolant accident (LOCA) or a steam line break, requires a reactor trip plus actuation of one or more of the engineered safety features in order to prevent or mitigate damage to the core and reactor coolant system components and ensure containment integrity.

In order to accomplish these design objectives, the engineered safety feature systems (ESFS) have proper and timely initiating signals which are supplied by the sensors, transmitters, and logic components making up the various instrumentation channels of the ESFAS.

The piping and instrumentation diagrams for the ESFS are included as figures in those sections of this FSAR where the mechanical systems are described. The location and layout drawings are referenced in Section 1.2. The electrical schematic diagrams and the control logic diagrams are referenced in Section 1.7. The engineered safety feature actuation logic diagrams are included as figures in this section, and are referenced in the appropriate ESF discussions below.

The auxiliary supporting ESFS function is described in Chapters 8.0, 9.0, and 10.0. Their controls function to support the primary ESF system is described in the support section. For each primary ESF system, a list of these auxiliary supporting engineered safety feature systems is provided in Table 7.3-12.

7.3.1 CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEM

7.3.1.1 Description

The concentration of hydrogen in the containment atmosphere is monitored by the system described in Section 6.2.5. The containment combustible gas control equipment (described briefly below and more completely in Section 6.2.5) maintains this hydrogen concentration below the minimum concentration capable of combustion. The emergency exhaust fans are described in Section 9.4.2.

7.3.1.1.1 System Description

a. Initiating circuits

The containment combustible gas control equipment is operated manually from control switches located in the main control room. It is not necessary for either recombiner or purge equipment to be initiated automatically because it would take approximately 5.1 days for the H_2 concentration to reach the control limit of 3 percent H_2 by volume with no H_2 recombiners in

operation. The hydrogen mixing fans automatically run at slow speed upon receipt of a safety injection signal.

b. Logic

The combustible gas control system is manually controlled, as shown by the drawings referenced in Section 1.7.

c. Bypass

Indication of system bypass is provided as described in Section 7.5.2.2. The CIS isolates the H_2 sampling and purge lines which can manually be reopened when necessary.

d. Interlocks

There are no interlocks on these controls.

e. Sequencing

On loss of offsite power coincident with SIS, the fans (which are MCC loads) are picked up as soon as the diesel generator output breaker is closed onto the bus.

f. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment.

g. Diversity

Diversity of control is provided in that the combustible gas control equipment may be controlled from local controls at motor control centers, as well as from the main control room panels.

h. Actuated devices

Table 7.3-1 lists the actuated devices.

i. Supporting systems

The supporting systems required for these controls are the Class 1E ac system (described in Section 8.3) and the containment atmosphere monitoring system (described in Section 6.2.5).

7.3.1.1.2 Design Bases

Design bases for the containment combustible gas control system are that operation will be controlled manually from the main control room and that no single failure shall prevent the containment combustible gas control system from functioning. In addition, the following conditions are considered for the control system components:

a. Range of transient and steady state conditions and circumstances

   The electrical power supply characteristics for the controls on this system are as described in Section 8.3. The range of possible environmental conditions for these controls is as described in Section 3.11(B).

b. Malfunctions, accidents, or other unusual events

Fire	Fire protection is discussed in Section 9.5.1.
Missile	Missile protection is discussed in Section 3.5.
Earthquake	Earthquake protection is discussed in Sections 3.7(B) and 3.7(N).

7.3.1.1.3 Drawings

There is no automatic actuation signal for this system, although the equipment controls include interfaces with sensors and with other devices. However, at the device level, the H_2 mixing fans automatically start, and the H_2 sampling system isolation valves automatically close, on receipt of CIS. References to the drawings associated with this system are provided as described in the introductory material for this section.

The final control logic diagrams for the individual devices are referenced in FSAR Section 1.7. These compare with the PSAR as follows:

a. Recombiner and emergency exhaust fan controls

   1. Recombiners: no functional change, added fault protection.

   2. Emergency exhaust fans. (See Section 7.3.3.1.3.)

b. Mixing fan controls

   Functionally the hydrogen mixing fans operate as shown in the diagrams referenced in Section 1.7. Details of motor overload protection have been added since the PSAR. The control switch maintains contact in slow and fast and has momentary contact for stop. The hydrogen mixing fans are loaded onto the diesel generators as soon as the diesels are able to accept

loads. The diesel generator load sequencing signal shown in the PSAR is, therefore, not shown on the control logic diagram for the hydrogen mixing fans.

The electrical schematic diagrams in Chapter 8.0 are in accordance with the control logic diagrams.

7.3.1.2 Analysis

a. Conformance to NRC general design criteria

The applicable criteria are listed in Table 7.1-2. No deviations or exceptions to those criteria are taken (see Section 3.1).

b. Conformance to Regulatory Guide 1.7 is described in Section 6.2.5.

c. Conformance to IEEE Standard 279-1971

The design of the control system is based on the applicable requirements of IEEE Standard 279-1971, as follows:

1. General Functional Requirement - Paragraph 4.1

   The H_2 mixing fans are able to function automatically and reliably over the full range of transients for all plant conditions for which credit was taken in the analyses. The rest of the system functions for all of these plant conditions when manually initiated. The system response time and accuracy are as required in the accident analyses. The H_2 sampling line is manually actuated.

2. Single Failure Criterion - Paragraph 4.2

   Through use of redundant, independent systems, as previously described, any single failure or multiple failures resulting from a single credible event will not prevent the system from performing its intended function, when required.

3. Quality of Components and Modules - Paragraph 4.3

   Components and modules used in the construction of the system exhibit a quality consistent with the nuclear power plant design life objective, require minimum maintenance, and have low failure rates. The program for quality assurance is described in Chapter 17.0.

4. Equipment Qualification - Paragraph 4.4

The system is qualified to perform its intended functions under the environmental conditions specified in Sections 3.10(B) and (N) and 3.11(B) and (N).

5. Channel Integrity - Paragraph 4.5

All channels will maintain functional capability under all conditions described in Section 7.3.1.1.2.

6. Channel Independence - Paragraph 4.6

Discussions of the means used to ensure channel independence are given in Sections 7.1.2.2 and 8.3.1.4.

7. Control and Protection System Interaction - Paragraph 4.7

No credible failure at the output of an isolation device will prevent the associated channel from performing its intended function. No single random failure in one channel will prevent the other channel from performing the intended function.

8. Derivation of System Outputs - Paragraph 4.8

To the extent feasible, the system inputs are from direct measurement of the desired variable.

9. Capability for Sensor Checks - Paragraph 4.9

Sufficient means have been provided to check the operational availability of the system.

10. Testing and Calibration - Paragraph 4.10

The control system has the capability of testing the devices used to derive the final system output.

11. Channel Bypass or Removal from Operation - Paragraph 4.11

Testing of one channel can be accomplished during reactor operation without initiating a protective action at the system level.

12. Operating Bypasses - Paragraph 4.12

    There are no permissive conditions on bypasses. Bypass of one channel will not bypass the other channel. Bypass of one system will not bypass any other system.

13. Indication of Bypass - Paragraph 4.13

    If the protective action of any part of the system has been bypassed or deliberately rendered inoperative, the fact will be continuously indicated in the control room, as described in Section 7.5.

14. Access to Means for Bypassing - Paragraph 4.14

    Appropriate administrative controls will be applied to ensure that access to the means for manually bypassing the system is adequately protected.

15. Multiple Set Points - Paragraph 4.15

    The system is designed so that there are no multiple setpoints.

16. Completion of Protective Action Once It is Initiated - Paragraph 4.16

    The system is designed so that once protective action is initiated, it is carried through to completion.

17. Manual Initiation - Paragraph 4.17

    Manual initiation of each function is provided in the control system with a minimum of equipment, by direct control of motor control centers and solenoid valves from panel-mounted control switches. System level actuation of the safety function is not provided since the time required for operation of these functions allows the station operator to take individual action for each controlled device.

18. Access to Set Point Adjustments, Calibration and Test Points - Paragraph 4.18

    Appropriate administrative controls will be applied to ensure that access to the means for adjusting, calibrating, and testing the system is adequately protected.

19. Identification of Protective Actions - Paragraph 4.19

    System protective actions are described and identified down to the channel level.

20. Information Readout - Paragraph 4.20

    Sufficient information is provided to allow the station operator to make a prompt decision regarding the system operating requirements. The indications required for these decisions are provided by supporting systems, as listed in the system description discussed in Section 7.3.1.1.1.i.

21. System Repair - Paragraph 4.21

    The system is designed to facilitate the recognition, location, replacement, repair, and adjustment of malfunctioning components or modules.

22. Identification - Paragraph 4.22

    Protection system components are identified, as described in Section 7.1.2.3.

d. Conformance to NRC regulatory guides

   The applicability of regulatory guides is as shown in Table 7.1-2. References to the discussions of these regulatory guides are presented in Section 7.1.2.5.1.

e. Failure modes and effects analysis

   See Table 7.3-2.

f. Periodic testing

   Periodic testing of the mechanical equipment associated with this system is discussed in Section 6.2.5. There is no automatic actuation equipment for the entire system, but there is automatic device actuation, as described in Section 7.3.1.1.3. Provisions for periodic testing of the containment isolation valves are discussed in Chapter 16, Table 16.6-1 and the Callaway Technical Specifications.

7.3.2 CONTAINMENT PURGE ISOLATION SYSTEM

7.3.2.1 Description

The containment purge isolation system detects any abnormal amount of radioactivity in the containment purge effluent, and initiates appropriate action to ensure that any release of radioactivity to the environs is controlled. The containment purge systems are also isolated by CIS.

7.3.2.1.1 System Description

a. Initiating circuits

Redundant and independent gaseous radiation monitors measure the radioactivity levels of the containment purge effluent. These monitors provide trip signals to bistable units in the ESF actuation system. The bistables generate redundant trip signals, and transmit them to the automatic actuation logic. Since the dampers also close on CIS, the initiating logic for CIS shown in Figure 7.2-1 (Sheet 8) is also applicable. These monitors are only required for automatic containment purge isolation in MODES 1 through 4. For plant conditions during CORE ALTERATIONS and during movement of irradiated fuel within containment, the function of the monitors is to alarm only and the trip signals for automatic actuation of CPIS may be bypassed. One instrumentation channel at a minimum is required for the alarm only function during refueling activities.

b. Logic

A logic diagram for the ESF actuation system is provided as Figure 7.3-1. This diagram shows only the actuation systems; it does not detail the bypass, bypass interlock, or test provisions. The logic for the containment purge isolation actuation subsystem is included in this figure.

The ESFAS hardware consists of solid-state bistables and logic elements, with electromechanical relays as the final output devices. The output relays are all energize-to-actuate, with contact operation as required for each actuated device.

The ESFAS is divided into three input-logic-output channels. These channels all meet the independence and separation criteria, as described elsewhere in this chapter. The logic channels are uniquely associated with the output channels. The input signals from all three input channels are isolated as necessary, and the isolated signals are transmitted to the logic channels as shown in Figure 7.3-1.

Interconnection of differing separation groups within the BOP ESFAS is by means of digital signal isolation modules. Analog signal isolation modules are included to provide isolated analog signals to the BOP computer.

Adequate physical separation or barriers are provided between differing separation groups, and wiring is routed in separated wireways, where appropriate. The wiring is color-coded with regard to separation group.

The digital signal isolation modules utilize optical isolators with appropriate signal and power conditioning circuits. The output circuits are powered by the devices receiving signals from the isolation modules, so no power isolation is required. There are no connections between the input and output circuits, except for the optical coupling in the isolation devices.

The analog signal isolation modules utilize transformers as the isolation devices. The analog input signals and the input power are converted to pulse trains and applied to the primary windings, and then they are reconstructed by circuits connected to the transformer secondaries. There are no connections between the input and output circuits, except for the magnetic coupling in the transformers.

Both the analog and the digital signal isolation modules are tested to ensure a minimum isolation potential of 1,500 Vac rms between the input terminals and the output terminals (all input terminals shorted together and all output terminals shorted together), and between the terminals and ground (all terminals shorted together). The 1,500 Vac rms test voltage was applied for at least 60 seconds for each test.

Once generated, any actuation signal remains present until it is manually reset. Each bistable automatically resets when its input signal returns to the "safe" side of the setpoint-deadband region.

An automatic test system is provided. The system periodically checks the operability of the channel, and alerts the plant operator, via the annunciator and BOP computer alarms, if a fault is detected. Provision is also included for manual testing. These test provisions do not compromise the integrity of any channel. They are isolated and will not propagate any fault, and the automatic test function is overridden by any actuation input. Bistable bypass switches are provided to permit the testing of bistables. The switches are key-locked, and the key cannot be removed from the lock unless the switch is in the "OPERATE" position. Visual indication of any bypass of any bistables is provided at the ESFAS cabinets; channel-level bypass indication is provided on the main control board.

c. Bypass

There is no device level override on this system. As discussed in Section 7.3.2.1.1.a this feature has relaxed requirements during CORE ALTERATIONS and during movement of irradiated fuel in containment.

d. Interlocks

There are no interlocks on these controls.

e. Sequencing

There is no automatic sequencing of operation. The system is permanently connected to the diesel bus and is energized as soon as the diesel output breaker closes.

f. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment. As discussed in Section7.3.2.1.1.a this feature has relaxed requirements during CORE ALTERATIONS and during movement of irradiated fuel in containment

g. Diversity

Diversity of sensing is provided in that containment purge isolation can be actuated by the containment purge gaseous radioactivity monitors, and by the CIS.

h. Actuated devices

Table 7.3-3 lists the actuated devices.

i. Supporting systems

Supporting systems for the containment purge isolation are the four 125-V dc power supplies discussed in Section 8.3 and the instrument air system described in Section 9.3.1. The isolation function is fail-safe with respect to all of these support systems, that is to say, loss of these support systems will not prevent isolation.

7.3.2.1.2 Design Bases

The design bases for the containment purge isolation system are described in Section 6.2.4.1.1 (Safety Design Bases 3 and 6) and Section 7.3.1.1.2 (as modified in Sections 7.3.2.1.1.a and 7.3.2.2).

7.3.2.1.3 Drawings

The logic for the containment purge isolation system is shown on the engineered safety feature actuation system logic diagram, Figure 7.3-1. The differences between this logic and that provided in the PSAR are as follows:

a. Logic memories are provided at the final actuation outputs, rather than on each digital input.

b. The indications and alarms for this system have been revised.

c. Purge supply fans (shutdown and mini): Additional details on overload protection, stop on containment purge isolation signal (CPIS) (isolated) from Westinghouse-supplied ESFAS, and stop on supply air low temperature.

d. Purge exhaust fans (shutdown and mini): Additional details on overload protection, stop on CPIS, and stop on high charcoal temperature in the exhaust filter-adsorber unit.

e. The purge system containment isolation dampers operate as shown in Figure 7.3-1. The system differs from the PSAR in that the CIS is replaced by the CPIS.

f. The containment minipurge fan discharge damper opens when the fan is running and closes when the fan is stopped.

7.3.2.2 Analysis

a. Conformance to NRC general design criteria

The applicable criteria are listed in Table 7.1-2. No deviations or exceptions to those criteria are taken. As discussed in Section 7.3.2.1.1.a this conformance is relaxed during CORE ALTERATIONS and during movement of irradiated fuel in containment.

b. Conformance to IEEE Standard 279-1971

The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in Section 7.3.1.2, except that the system actuation is automatic. The radiation monitor ranges and setpoints are in Table 11.5-3, Table 12.3-3, and Section 16.11.2.4. As discussed in Section 7.3.2.1.1.a this conformance is relaxed during CORE ALTERATIONS and during movement of irradiated fuel in containment.

c. Conformance to NRC regulatory guides

The applicability of the regulatory guides is as shown in Table 7.1-2. References to the discussions of these regulatory guides are presented in Section 7.1.2.5.1. As discussed in Section 7.3.2.1.1.a this conformance is relaxed during CORE ALTERATIONS and during movement of irradiated fuel in containment.

d. Failure modes and effects analysis

See Table 7.3-4.

e. Periodic testing

Periodic testing of the mechanical equipment associated with this system is discussed in Section 9.4. Periodic testing of the actuation system is discussed in the Callaway Technical Specifications.

7.3.3 FUEL BUILDING VENTILATION ISOLATION

7.3.3.1 Description

Upon detection of high radioactivity by the fuel building exhaust gaseous radioactivity monitors, the fuel building ventilation system is automatically realigned through the ESFAS to meet the following requirements:

a. Isolate normal ventilation.

b. Initiate operation of the emergency exhaust system to maintain the fuel building atmosphere at a negative pressure.

c. Reduce the flow of fuel building air to the outside atmosphere to a minimum consistent with maintaining the required building negative pressure.

d. Filter the exhaust air through HEPA and charcoal filters.

A description of the entire fuel building ventilation system is given in Section 9.4.

7.3.3.1.1 System Description

a. Initiating circuits

Two independent gaseous radioactivity monitors measure the radioactivity level in the fuel building exhaust line, and provide trip signals to bistable

units in the ESF actuation system. The bistable units generate two redundant trip signals, and transmit them to the automatic actuation logic.

The emergency exhaust system is on standby for an automatic start following receipt of a fuel building isolation signal or an SIS. The initiation of the LOCA mode of operation (SIS signal) takes precedence if both signals are received so that the emergency ventilation is directed to the auxiliary building (see Section 9.4).

b. Logic

The logic for the fuel building ventilation isolation actuation system is included in Figure 7.3-1. The actuation signal is transmitted to each actuated device, and causes each device to assume its "safe" state.

c. Bypass

There is no device level override on this system.

d. Interlocks

There are no interlocks on these controls.

e. Sequencing

There is no automatic sequencing of operation. The system is permanently connected to the diesel bus and is energized as soon as the diesel output breaker closes.

f. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment. There are two channels of actuation initiated by redundant radioactivity monitors or redundant manual initiation switches.

g. Diversity

Diversity of control is provided in that the fuel building ventilation isolation system can be actuated by either automatic signals or manual control.

h. Actuated devices

Table 7.3-5 lists the actuated devices.

i. Supporting systems

Supporting systems for the fuel building ventilation isolation system actuation are the four 125-V dc power supplies discussed in Section 8.3 and the instrument air system described in Section 9.3.1. The isolation function is fail-safe with respect to all of these support systems; that is to say, loss of these support systems will not prevent isolation.

7.3.3.1.2 Design Bases

The design bases for the fuel building ventilation isolation system are discussed in Section 9.4.2.1.1 (Safety Design Bases 1, 3, 4, and 6).

Additionally, the design bases described in Section 7.3.1.1.2 are applicable for the control system components.

7.3.3.1.3 Drawings

The logic diagram for the fuel building ventilation isolation actuation system is included in Figure 7.3-1. The differences between this logic and that provided in the PSAR are the same as those for the containment purge isolation system (see Section 7.3.2.1.3). In addition, actuation system reset is not provided in the fuel building.

The control logic diagrams, the electrical schematic diagrams, the piping and instrument diagrams, and the physical location drawings for this system are included in the references in the introductory material for this section.

7.3.3.2 Analysis

a. Conformance to NRC general design criteria

   The applicable criteria are listed in Table 7.1-2. No deviations or exceptions to those criteria are taken.

b. Conformance to IEEE Standard 279-1971

   The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in Section 7.3.1.2c, except that the system functions automatically. The radiation monitor trip setpoint is provided in the Callaway Technical Specifications.

c. Conformance to NRC regulatory guides

   The applicability of the regulatory guides is as shown in Table 7.1-2. References to the discussions of conformance to these regulatory guides are presented in Section 7.1.2.5.1.

d. Failure modes and effects analysis

See Table 7.3-6.

e. Periodic testing

Periodic testing of the mechanical equipment associated with this system is discussed in Section 9.4.2. Provisions for the periodic testing of the actuation system are discussed in the Callaway Technical Specifications.

7.3.4 CONTROL ROOM VENTILATION ISOLATION

7.3.4.1 Description

Upon detection of high gaseous radioactivity levels, the normal supply of outside air to the control room will be terminated, as described in Section 6.4. In this event, the control room air will be recycled and filtered, and a small supply of fresh makeup air will be provided. The control room will be maintained at a set positive pressure to prevent the ingress of the local ambient atmosphere. Normal ventilation will be restored only by manual operation by the plant operator, and will be maintained only if the local ambient atmosphere poses none of the monitored hazards.

7.3.4.1.1 System Description

a. Initiating circuits

The gaseous radioactivity level of the air provided to the main control room from the local ambient atmosphere is monitored.

If acceptable levels are exceeded, trip signals from these monitors are transmitted to bistables in the ESFAS isolating the control room as described above. Monitors are also provided to measure the particulate and iodine radioactivity levels in the normal supply air.

The sensitivities and response times of these monitors are listed in Table 7.3-7.

In addition to the above, control room isolation will be initiated upon:

1. Fuel building ventilation isolation
2. Containment isolation Phase A
3. Manual initiation
4. High containment purge radioactivity level (CPIS)

b. Logic

The control room ventilation isolation actuation system logic is included in Figure 7.3-1. The actuation signal is transmitted to each actuated device, and, subject to the provisions of bypass or override, causes each device to assume its "safe" state.

c. Bypass

Manual override is available by means of pull-to-lock switches on the fans.

d. Interlocks

There are no interlocks on these controls.

e. Sequencing

CRVIS is sequenced to Class 1E and control room HVAC units.

f. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment. Redundancy is provided in the gaseous radioactivity monitors, the actuation signals, and manual actuation switches.

g. Diversity

Diversity of actuation is provided in that the control room ventilation system may be isolated by either an automatic system or by operator manual actuation. Diversity is provided by actuation from the gaseous radioactivity and manual switches.

h. Actuated devices

Table 7.3-8 lists the actuated devices.

i. Supporting system

The supporting system required for the controls is the vital Class 1E ac system described in Section 8.3.

7.3.4.1.2 Design Bases

The design bases for the control room ventilation isolation system are that no single failure shall prevent the isolation of the control room ventilation system. The radiation monitor trip setpoint is provided in the Callaway Technical Specifications.

Additionally, the design bases described in Section 7.3.1.1.2 are applicable to the control system components.

7.3.4.1.3 Drawings

The logic diagram for the control room ventilation isolation actuation system is included in Figure 7.3-1. The differences between this logic and that presented in the PSAR are the same as those for the containment purge isolation system, Section 7.3.2.1.3.

Other drawings pertaining to this system are included in the references in Section 1.7.

7.3.4.2 Analysis

a. Conformance to NRC general design criteria

   The applicable criteria are listed in Table 7.1-2. No deviations or exceptions to those criteria are taken.

b. Conformance to IEEE Standard 279-1971

   The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in Section 7.3.1.2c, except that the system is automatically actuated. The setpoints are provided in the Callaway Technical Specifications.

c. Conformance to NRC regulatory guides

   The applicability of regulatory guides is as shown in Table 7.1-2. References to the discussions of these regulatory guides are presented in Section 7.1.2.5.1.

d. Failure modes and effects analysis

   This analysis is given in Table 7.3-9.

e. Periodic testing

   Periodic testing of the mechanical equipment associated with this system is discussed in Section 9.4.1. Provisions for the periodic testing of the actuation system are discussed in the Callaway Technical Specifications.

7.3.5 DEVICE LEVEL MANUAL OVERRIDE

7.3.5.1 Description

The purpose of device level manual override is to provide the capability for manually overriding the actuation signal command when there is an operational need to do so in the post-event situation. This equipment is only included in the designs of the post-event monitoring and sampling systems to allow manual override of the containment isolation signal. When the override function has been achieved, an amber light on the main control board indicates that the device has been removed from the state initiated by the actuation signal. Operation of the control switch to the position corresponding to the actuation signal command is indicated by extinguishing the amber light indication. Logic diagrams are referenced in Section 1.7.

7.3.5.2 Analysis

The design of the override feature is in conformance with the criteria, guides, and standards applicable to the control circuits to which it is applied. Failure modes and effects analysis are provided in Table 7.3-10.

7.3.6 AUXILIARY FEEDWATER SUPPLY

7.3.6.1 Description

The auxiliary feedwater system (AFS) consists of two motor-driven pumps, one steam turbine-driven pump, and piping, valves, instruments, and controls, as shown in Figure 10.4-9. The pumps are started automatically on receipt of signals from the actuation logic, as shown in Figure 7.3-1. All three pumps can also be started manually from control switches in the control room or at the auxiliary shutdown control panel.

The two sources of water for the AFS are the nonsafety-related condensate storage tank (CST) and the nonsafety-related hardened condensate storage tank (HCST). However, these tanks are not seismic Category I and are not credited for accident mitigation.

An automatic subsystem is provided, therefore, to monitor the water supply pressure from the CST and initiate switchover to the essential service water system should the supply from the nonsafety-related condensate storage tank be interrupted.

Each motor-driven pump feeds two steam generators through individual motor-operated flow control valves. AFS flow can be regulated manually from the control room or from the auxiliary shutdown control panel.

The turbine-driven pump feeds all four steam generators through individual air-operated flow control valves. AFS flow can be regulated manually from the control room or from the auxiliary shutdown control panel.

AFS flow indication is provided for each steam generator in the control room and at the auxiliary shutdown control panel.

The AFS pump turbine is supplied with motive power from two main steam lines through two normally closed, air-operated steam supply valves. A normally closed motor-operated trip and throttle valve is also provided at the inlet to the pump driver. Control of the steam supply valves and trip and throttle valve, as well as manual speed control for the turbine-driven pump, is provided in the control room and at the auxiliary shutdown control panel.

The status of the motor-driven pumps, the turbine-driven pump, the turbine steam supply valves, and the trip and throttle valve is indicated in the control room and at the auxiliary shutdown control panel. The AFS flow to each steam generator is indicated on both the main control board and at the auxiliary shutdown control panel.

The AFS equipment is described in Section 10.4.9.

The auxiliary feedwater (AFW) system automatically supplies feedwater to the steam generators to remove decay heat from the reactor coolant system upon the loss of the normal feedwater supply. The motor-driven AFW pumps start automatically upon steam generator water level low-low in any steam generator, upon trip of both turbine-driven MFW pumps (an anticipatory start signal for which no credit is taken in any accident analysis), upon actuation of AMSAC (anticipated transient without scram mitigation system actuation circuitry), and upon actuation by the LOCA sequencer or shutdown sequencer. The turbine-driven AFW pump is automatically started by steam generator water level low-low in any two steam generators, 4.16-kV safety-related bus NB01 or NB02 undervoltage, and upon actuation of AMSAC. All three AFW trains can also be manually actuated. Initiating circuitry is described further in Section 7.3.6.1.1.a.

In addition to initiating functions described above, the auxiliary feedwater actuation signal (AFAS) closes the steam generator blowdown and sample isolation valves, when auxiliary feedwater is required by plant conditions. All remote manually operated valves in the suction from the nonsafety-related CST and in the discharge to the steam generators are normally open.

Certain actuations during Control Room evacuation in a fire event are not automatic but require recovery actions. Specific detail on Control Room fire is discussed in Section 9.5.1.

7.3.6.1.1 System Description

a. Initiating circuits

The motor-driven pumps are started on the occurrence of any one of the following signals:

1. Manual start

2. Safeguards sequence signal (initiated by safety injection signal or loss-of-offsite-power)

3. Auxiliary feedwater actuation (AFAS-M)

AFAS-M is generated on the occurrence of any one of the following events:

1. Trip of both main feedwater pumps (Manual block of the main feed pump trip signals is provided at the main control board, and is indicated on the ESFAS status panel. This block permits startup and shutdown of the plant without automatic start of the AFPs, while allowing the AFPs to remain available to respond to a demand from any other source.)

2. 2 out of 4 low-low level signals for any one steam generator (at solid state protection system)

3. ATWS Mitigation System Actuation Circuitry (AMSAC)

4. Manual AFAS-M initiation

The turbine-driven pump is started on the occurrence of either of the following signals:

1. Manual start

2. Auxiliary feedwater actuation (AFAS-T)

AFAS-T is generated on the occurrence of any one of the following events:

1. Loss-of-offsite-power

2. Low-low level for any two steam generators (at solid state protection system)

3. ATWS Mitigation System Actuation Circuitry (AMSAC)

4. Manual AFAS-T initiation

The steam generator sample line containment isolation valves and the steam generator blowdown isolation valves are all automatically closed on the occurrence of a safety-injection signal, a loss-of-offsite-power signal, or an AFAS. The signal which causes this closure is reset automatically upon reset of the AFAS.

b. Logic

See Figures 7.3-1 and 7.7-16.

c. Bypass

There is no device level override on this system.

Section 7.7.1.11 discusses AMSAC bypass capabilities.

d. Interlocks

The auxiliary feedwater supply valves from the nonsafety-related condensate storage tank and from the ESW system are interlocked with the CST supply pressure sensors, in the presence of an Auxiliary Feedwater Actuation signal, receipt of 2-out-of-3 low pressure signals initiates switchover to essential service water. The AMSAC is blocked when 1-out-of-2 turbine impulse chamber pressure signals corresponds to less than 40% of reactor power, after a 360 sec. time delay.

e. Redundancy

Sufficient actuation and control channels are provided throughout the auxiliary feedwater system to ensure the required flow to at least two steam generators in the event of a single failure.

f. Diversity

The auxiliary feedwater system is diversified by utilizing a turbine-driven pump with air and dc motor-operated valves and two ac motor-driven pumps with ac motor-operated valves as described in Section 10.4.9. Diversity in initiating signals can be seen on Figure 7.3-1.

g. Actuated devices

1. Auxiliary feedwater pump turbine steam supply valves (2)

2. Auxiliary feedwater pump trip and throttle valve (1)

3. Auxiliary feedwater flow control valves (8) (manual only)

4. Auxiliary feedwater pump electric motors (2)

5. Essential service water supply valves (4)

6. Condensate storage tank supply valves (3)

7. Steam generator blowdown isolation valves (4)

8. Steam generator blowdown sample isolation valves (8)

h. Supporting systems

The Class 1E electric system is required for auxiliary feedwater control. The pressurized gas supply required for motive force is normally supplied from the instrument air header, which is not safety related. In addition, each valve has a seismic Category I auxiliary gas supply (see Section 9.3.1).

i. Portion of system not required for safety

Instrumentation provided for monitoring system performance (refer to Section 7.5.3.5) is not required for safety. The AMSAC is not required for safety.

7.3.6.1.2 Design Bases

Auxiliary feedwater is required, as described in Section 10.4.9. No single failure shall prevent this system from operating.

Additionally, Section 7.3.1.1.2 is applicable to the control system components.

The system must provide full auxiliary feedwater flow within 60 seconds of the detection of any condition requiring auxiliary feedwater. AMSAC will, in the absence of the RPS, initiate AFW flow within 90 seconds of an ATWS event.

7.3.6.1.3 Drawings

The logic diagram for the auxiliary feedwater supply actuation system is included in Figure 7.3-1. The differences between this logic and that provided in the PSAR are the same as those discussed for the containment purge isolation system.

Other drawings pertaining to this system are included in Section 7.3 and 7.7.1.11. The logic associated with automatic switchover to the ESW has been added.

7.3.6.2 Analysis

a. Conformance to NRC general design criteria

1. General Design Criterion 13

Instrumentation necessary to monitor station variables associated with hot shutdown is provided in the main control room and on the

auxiliary shutdown control panel. Controls for the auxiliary feedwater system are provided at each location. A description of the surveillance instrumentation is provided in Section 7.5.

2. General Design Criterion 19

All controls and indications required for safe shutdown of the reactor are provided in the main control room. In the event that the main control room must be evacuated, adequate controls and indications are located outside the main control room to (1) bring to and maintain the reactor in a hot standby condition and (2) provide capability to achieve cold shutdown.

The auxiliary shutdown control panel, located outside the main control room, is described in Section 7.4.3.

3. General Design Criterion 34

The auxiliary feedwater system provides an adequate supply of feedwater to the steam generators to remove reactor decay heat following reactor trip. Two steam generators with auxiliary feedwater supply are sufficient to remove reactor decay heat without exceeding design conditions of the reactor coolant system.

4. Other general design criteria

The remaining applicable general design criteria are listed in Table 7.1-2 and Section 10.4.9. No exceptions are taken to those criteria.

b. Conformance to IEEE Standard 279-1971

The design of the control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in Section 7.3.1.2c, except that this system is automatically actuated. The setpoints for safety injection, steam generator water level low-low, and for pump suction transfer to ESW are provided in the Callaway Technical Specifications.

During testing of the two-out-of-three low pressure supply instrument channels, it is permitted to disconnect the instrument transmitter leads at the instrument rack to simulate the transmitter signals. This is consistent with the instrument cabinet design.

c. Conformance to NRC regulatory guides

The applicability of regulatory guides is shown in Table 7.1-2. References to the discussions of these regulatory guides are presented in Section 7.1.2.5.1.

d. Failure modes and effects analysis

See Table 7.3-11.

e. Periodic testing

Periodic testing of the mechanical equipment associated with this system is discussed in Section 10.4.9.4. Provisions for the periodic testing of the actuation system are discussed in the Callaway Technical Specifications. See Section 7.7.1.11 for a discussion of AMSAC testing provisions.

7.3.7 MAIN STEAM AND FEEDWATER ISOLATION

7.3.7.1 Description

The signals that initiate automatic closure of the main steam and feedwater isolation valves are generated in the ESFAS described in Section 7.3.8. The logic diagrams for the generation of these signals are shown in Figure 7.2-1 (Sheets 8 and 13). The remainder of this section concentrates on the non-Westinghouse portion of the main steam and feedwater isolation system (MSFIS).

The main steam and feedwater isolation valves are operated by system-medium actuators. The actuators are powered by the system-medium, which is controlled by electrically operated solenoid valves. Each main steam and feedwater isolation valve has six solenoid valves, three in each actuation train. Each actuation train is powered from a separate Class 1E electrical system and is capable of closing the valve independent of the opposite actuation train.

The non-Westinghouse MSFIS consists of two independent Class 1E actuation trains. Within each train, three Programmable Logic Controllers (PLCs) produce a 2 out of 3 logic configuration for each actuation relay per valve. The use of the same software in the PLCs in each train can produce the possibility of a Common Mode Software Failure (CMSF). Consequently, a diverse backup means to fast close the main steam isolation valves through the use of an Emergency Override Panel and Fast Close toggle switches is included in each train to mitigate the consequences of the CMSF.

7.3.7.1.1 System Description

a. Initiating circuits

The main steam and feedwater isolation valves close automatically upon receipt of an automatic close signal from the Westinghouse solid state protection system (SSPS). Manual operation is also provided.

Two manual Fast Close swtiches are provided for the main steam isolation valves. Each switch has the capability to actuate both actuation trains associated with all four valves. Train isolation at the switches is assured by fire retardant sleeving on the wire going to the switches and by qualification testing that was performed on the switches. This feature is provided to conserve main steam that would be lost to the condenser in the event of a single train actuation.

Two manual Fast Close switches are provided for the feedwater isolation valves. Each swtich has the capability to actuate both actuation trains associated with all four valves. Train isolation at the switches is assured by fire retardant sleeving on the wire going to the swtiches, and by qualification testing that was performed on the swtiches. This feature is provided to conserve feedwater that would be lost to the condenser in the event of a single train actuation. Refer to Table 7.1-5 Postion 5.

b. Logic

In addition to the manual and automatic trip modes of operation, manual controls are provided for opening and closing the main steam and main feedwater isolation valves.

c. Bypass

See Section 7.3.8.

d. Interlocks

See Section 7.3.8.

e. Redundancy

Two complete actuation trains are provided for each actuator. Each actuation train consists of three solenoid valves and is capable of closing the main steam and main feedwater isolation valve regardless of the state of the opposite actuation train.

f. Diversity

See Section 7.3.8 for a discussion of diversity with regard to the automatic actuation signal.

g. Actuated devices

The actuated devices are the main steam and feedwater isolation valves.

h. Supporting systems

The system makes use of the Class 1E dc power system and of the compressed gas system (for testing only).

i. Portions of the system not required for safety

For the main steam and main feedwater isolation valves, each actuation train includes provisions to ‘Normal Close’ the valves, while both actuation trains are required to remotely ‘Open’ the valves. This function is not required for safety. The vent lines downstream of the safety related rupture disk, which include manual isolation valves, along with the actuation position indication, are also not required for safety.

7.3.7.1.2 Design Bases

The design bases for the main steam and feedwater isolation actuation system are provided in Section 7.3.8. The design bases for the remainder of the main steam and feedwater isolation system are that the system isolates the main steam and feedwater when required, and that no single failure can prevent any valve from performing its required function. See Section 7.3.8 for additional discussion.

In addition, Section 7.3.1.1.2 is applicable to the control system components.

7.3.7.1.3 Drawings

See Figures 7.2-1 (Sheet 8), 7.3-2, and 7.3-3. Other drawings pertaining to this system are included in the introductory material for this section.

7.3.7.2 <u>Analysis</u>

a. Conformance to NRC general design criteria

See Section 7.3.8.

b. Conformance to IEEE Standard 279-1971

The design of the valve control system conforms to the applicable requirements of IEEE Standard 279-1971, as listed and discussed in Section 7.3.1.2, except that the system is automatically actuated. The setpoints are provided in the Callaway Technical Specifications.

c. Conformance to NRC regulatory guides

See Section 7.3.8.

d. Failure modes and effects analysis

See Table 10.3-3 and Table 10.4-7.

e. Periodic testing

The valve control system includes provisions for verifying the proper operation of the electronic logic circuits. The frequency of actuation system testing is provided in the Callaway Technical Specifications. The mechanical system testing provisions are given in Technical Specification 3.7 and FSAR Sections 10.3.4 and 10.4.7.4.

Note that each valve can be closed within the appropriate time limit by either actuator side. Testing is administratively controlled to ensure that both sides of a given actuator will not be set to "TEST" mode simultaneously.

7.3.8 NSSS ENGINEERED SAFETY FEATURE ACTUATION SYSTEM

7.3.8.1 Description

The Westinghouse solid state protection system (SSPS) consists of two parts: the reactor trip system (RTS), which is described in Section 7.2, and the engineered safety feature actuation system (ESFAS), which is described here. The ESFAS monitors selected plant parameters and, if predetermined safety limits are exceeded, transmits signals to logic matrices sensitive to combinations indicative of primary or secondary system boundary ruptures (Condition III or IV events). When certain logic combinations occur, the system sends actuation signals to the appropriate engineered safety feature components. The ESFAS meets the requirements of GDCs 13, 20, 21, 22, 23, 24, 25, 27, 28, 34, 35, 37, 38, 40, 41, 43, 44, 46, 54, 55, and 56.

7.3.8.1.1 System Description

The equipment which provides the actuation functions is listed below and discussed in this section. (For additional background information, see References 1, 2, and 3.)

a. Process instrumentation and control system (Ref. 1)

b. Solid state logic protection system (Ref. 2)

c. Engineered safety feature test cabinet (Ref. 3)

d. Manual actuation circuits

The ESFAS consists of two discrete portions of circuitry: 1) an analog portion consisting of three or four redundant channels per parameter or variable to monitor various plant parameters, such as the reactor coolant system and steam system pressures, temperatures and flows, and containment pressures; and 2) a digital portion consisting of two redundant logic trains which receive inputs from the analog protection channels and perform the logic needed to actuate the engineered safety features. Each digital train is capable of actuating the engineered safety feature equipment required. Any single failure within the engineered safety feature actuation system does not prevent system action, when required.

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

The variables are sensed by the analog circuitry, as discussed in Reference 1 and in Section 7.2. The outputs from the analog channels are combined into actuation logic, as shown in Figure 7.2-1 (Sheets 5, 6, 7, and 8). Tables 7.3-13 and 7.3-14 give additional information pertaining to logic and function.

Analog Circuitry

The process analog sensors and racks for the engineered safety feature actuation system are described in Reference 1. This reference discusses the parameters to be measured, including pressures, flows, tank and vessel water levels, and temperatures, as well as the measurement and signal transmission considerations. These latter considerations include the transmitters, orifices and flow elements, resistance temperature detectors, as well as automatic calculations, signal conditioning, and location and mounting of the devices.

The sensors monitoring the primary system are shown on Figure 5.1-1. The secondary system sensor locations are shown on the steam system flow diagrams given in Chapter 10.0.

Containment pressure is sensed by four physically separated differential pressure transmitters located outside of the containment (which are connected to the containment atmosphere by a filled and sealed hydraulic transmission system). The distance from

penetration to transmitter is kept to a minimum. This arrangement, together with the pressure sensors external to the containment, forms a double barrier and conforms to GDC-56 and Regulatory Guide 1.11. Separation is maintained for transmitters, GNPT0934 and GNPT0936. However, physical separation of the impulse lines, per Reference 3, is not maintained for transmitters GNPT0935 and GNPT0937. This latter separation is not required due to the instruments not being impacted by incidents such as missiles, pipe whip, high pressure jets, or falling objects from LOCA or MSLB accidents. Thus, no adverse impact is produced as a result of this lack of separation.

Digital Circuitry

The engineered safety feature logic racks are discussed in detail in Reference 2. The description includes the considerations and provisions for physical and electrical separation, as well as details of the circuitry. References 5, 6, and 7 provide additional discussion on the replacement logic rack circuit boards associated with active safety functions. These references also cover certain aspects of on-line test provision, provisions for test points, consideration for the instrument power source, and considerations for accomplishing physical separation. The outputs from the analog channels are combined into actuation logic, as shown on Sheets 5, 6, 7, 8, and 14 of Figure 7.2-1.

a. Initiating circuits

   1. Containment pressure (see Table 7.3-14)

   2. Steam line pressure (see Table 7.3-14)

   3. Steam line pressure rate (see Table 7.3-14)

   4. Manual (see Tables 7.3-13 and 14)

      Manual actuation switches are provided on the main control board for the safety injection signal (SIS), the containment isolation signal phase-A (CIS-A), and containment isolation signal phase-B/ containment spray actuation signal (CIS-B/CSAS). The switches are momentary-contact and are arranged and operate as follows:

      (a) SIS: Two switches, each with two sets of contacts connected mechanically but electrically isolated. One set of contacts in each switch is wired to separation group 1, the other to separation group 4. Operation of either switch actuates both trains of the SIS. The switch wiring is in accordance with the separation requirements of IEEE 279-1971.

(b) CIS-A: Two switches arranged and wired as described for SIS. Operation of either switch actuates both trains of the CIS-A.

(c) CIS-B/CSAS: Two sets of two switches each, each switch arranged and wired as described for SIS. Operation of both switches in either set activates both trains of both CIS-B and CSAS. Operation of any one switch, or of any two switches not in the same set does not actuate CIS-B/CSAS.

Manual controls in the control room are also provided to switch from the injection to the recirculation phase after a LOCA.

b. Logic

The actuation logic is shown in Figure 7.2-1 (Sheets 5, 6, 7, and 8). Tables 7.3-13 and 7.3-14 give additional information pertaining to the logic.

c. Bypass

Bypasses are designed to meet the requirements of IEEE Standard 279-1971, Sections 4.11, 4.12, 4.13, and 4.14. Bypasses are provided to permit testing of the fast-close logic circuitry. However, access to the bypass switches is administratively controlled to prevent simultaneous bypass of both actuation channels for any one valve. The bypass condition is indicated in the main control room. The P-4/Low T_{avg} bypass switch does not have to meet Section 4.12 of IEEE 279-1971 since this feedwater isolation circuitry does not provide a protective function.

d. Interlocks

Interlocks are also discussed in Sections 7.2, 7.6, and 7.7. The protection (P) interlocks are given on Tables 7.2-2 and 7.3-15. The safety analyses demonstrate that the protective systems ensure that the NSSS will be put into and maintained in a safe state following a Condition II, III, or IV accident commensurate with pertinent criteria in the Callaway Technical Specifications. The protective systems have been designed to meet IEEE Standard 279-1971 and are entirely redundant and separate, including all permissives and blocks. All blocks of a protective function are automatically cleared whenever the protective function is required to function in accordance with GDC-20, GDC-21, and GDC-22 and Sections 4.11, 4.12, and 4.13 of IEEE Standard 279-1971 (except as discussed under c. above). Control interlocks (C) are identified in Table 7.7-1. Because control interlocks are not safety-related, they have not been specifically designed to meet the requirements of IEEE Protection System Standards.

The interlocks associated with NSSS engineered safety feature actuation system are outlined in Table 7.3-15.

e. Sequencing

The containment spray pumps start 15 seconds after a CSAS with no undervoltage condition present. With an undervoltage condition, 12 seconds must be added for diesel startup.

f. Redundancy

Redundancy for the system is provided by redundant process channels which are physically and electrically separated. Redundant train logic is also provided in the SSPS, which is physically and electrically separated. The process signals are combined from the process control systems into the SSPS according to the prescribed logic defined in Sections 7.2 and 7.3 to produce actuation signals for RTS and ESFS operations.

g. Diversity

Functional diversity, as described in Reference 4, has been designed into the system. The extent of diverse system variables has been evaluated for postulated accidents. Generally, two or more diverse protection functions would automatically terminate an accident before unacceptable consequences could occur.

1. Regarding the engineered safety feature actuation system for a LOCA, a safety injection signal can be obtained manually or by automatic initiation from either of two diverse parameter measurements.

    (a) Low pressurizer pressure.

    (b) High containment pressure (Hi-1).

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

    (a) Lead-lag compensated low steam line pressure.

    (b) For a steam line break inside containment, high containment pressure (Hi-1) provides an additional parameter for generation of the signal.

    (c) Low pressurizer pressure.

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

h. Actuated devices

Function Initiation

The specific functions which rely on the ESFAS for initiation are:

1. A reactor trip, provided one has not already been generated by the reactor trip system.

2. Cold leg injection isolation valves which are opened for injection of borated water by safety injection pumps into the cold legs of the reactor coolant system.

3. Charging pumps, safety injection pumps, residual heat removal pumps, and associated valving which provide emergency makeup water to the cold legs of the reactor coolant system following a LOCA.

4. Containment air recirculation fans and cooling system which serve to cool the containment and limit the potential for release of fission products from the containment by reducing the pressure following an accident.

5. Those pumps which serve as part of the heat sink for containment cooling (e.g., service water and component cooling water pumps).

6. Motor-driven auxiliary feedwater pumps.

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

8. Steam line isolation to prevent the continuous, uncontrolled blowdown of more than one steam generator and thereby uncontrolled reactor coolant system cooldown (see Section 7.3.7).

9. Main feedwater line isolation as required to prevent or mitigate the effect of excessive cooldown.

10. Start the emergency diesels to ensure a back-up supply of power to the emergency and supporting systems components.

11. Isolate the control room intake ducts to meet control room occupancy requirements following a LOCA (see Section 7.3.4).

12. Containment spray actuation which performs the following functions:

    (a) Initiates containment spray to reduce containment pressure and temperature following a loss-of-coolant or steam line break accident inside of the containment.

    (b) Initiates Phase B containment isolation which isolates the containment following a LOCA, or a steam or feedwater line break within the containment to limit radioactive releases. (Phase B isolation, together with Phase A isolation, results in isolation of all but safety injection and spray lines penetrating the containment.)

<u>Final Actuation Circuitry</u>

The outputs of the solid state logic protection system (the slave relays) are energized to actuate, as are most final actuators and actuated devices. These devices are listed as follows:

1. Safety injection system pump and valve actuators. See Section 6.3 for flow diagrams and additional information.

2. CIS-A isolates all nonessential process lines on receipt of safety injection signal. CIS-B isolates the remaining process lines (which do not include safety injection lines) on receipt of a 2/4 hi-3 containment pressure signal. For further information, see Section 6.2.4.

3. Emergency fan coolers (see Section 6.2.2.2)

4. Essential service water pump and valve actuators (see Section 9.2.1.2)

5. Auxiliary feedwater pumps start (see Section 10.4.9)

6. Diesel start (see Section 8.3)

7. Feedwater isolation (see Section 10.4.7)

8. Ventilation isolation valves and damper actuator (see Section 6.4)

9. Steam line isolation valve actuators (see Section 7.3.7 and Section 10.3)

10. Containment spray pump and valve actuators (see Section 6.2.2)

If an accident is assumed to occur coincident with a loss of offsite power, the engineered safety feature loads must be sequenced onto the diesel generators to prevent overloading them. This sequence is discussed in Section 8.3. The design meets the requirements of GDC-35.

i. Support systems

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

1. Essential service water system - heat removal (see Section 9.2.1)

2. Component cooling water system - heat removal (see Section 9.2)

3. Electrical power distribution systems (see Section 8.3)

4. Essential HVAC systems (see Section 9.4)

Table 7.3-12 provides a list of the auxiliary support ESF systems.

j. Portion of system not required for safety

The system produces annunciator, status light, and computer input signals to indicate individual channel status. The system provides signals to the reactor trip annunciators for sequence of events indication, and indicates the condition of blocks and permissives. Semiautomatic testing features are provided for on-line testing. All monitoring for the testing is at the protection system cabinets. Equipment used to accomplish these functions is isolated from the protection functions and is not required for the safety of the plant. Section 7.3.7.1.1.i discusses individual steam and feedwater isolation control switches that are not required for safety.

7.3.8.1.2 Design Bases

The functional diagrams presented in Figure 7.2-1 (Sheets 5, 6, 7, and 8) provide a graphic outline of the functional logic associated with requirements for the ESFAS. Requirements of the ESFS are given in Chapter 6.0. The design bases information required in IEEE Standard 279-1971 is given in Sections 7.3.1.2c and 7.3.8.2b.

a. Automatic actuation requirements

The ESFAS receives input signals (information) from the reactor plant and containment and automatically provides timely and effective signals to actuate the components and subsystems comprising the ESFAS.

b. Manual actuation requirements

The ESFAS has provisions in the control room for manually initiating the functions of the engineered safety feature system.

c. Equipment protection

Equipment related to safe operation of the plant is designed, constructed, and installed to protect it from damage. This is accomplished by conformance to accepted standards, criteria, and consideration of potential environmental conditions. The criteria for equipment protection are given in Chapter 3.0. As an example, certain equipment is seismically qualified in accordance with IEEE Standard 344-1975. During construction, independence and separation is achieved, as required by IEEE Standard 279-1971, IEEE Standard 384-1974, and Regulatory Guide 1.75, either by barriers, physical separation, or demonstration test. This serves to protect against complete destruction of a system by fires, missiles, or other hazards.

7.3.8.1.2.1 Generating Station Conditions

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

a. Primary system

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

2. Rupture of a reactor coolant pipe (LOCA).

3. Steam generator tube rupture.

b. Secondary system

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

2. Rupture of a major steam pipe.

7.3.8.1.2.2 Generating Station Variables

The following list summarizes the generating station variables required to be monitored for the automatic initiation of safety injection during each accident identified in the preceding section. Post-accident monitoring requirements are given in Table 7.5-1.

a. Primary system accidents

1. Pressurizer pressure

2. Containment pressure (not required for steam generator tube rupture)

b. Secondary system accidents

1. Pressurizer pressure

2. Steam line pressures and pressure rate

3. Containment pressure

7.3.8.1.2.3 Spatially Dependent Variables

The only variable sensed by the ESFAS which has spatial dependence is reactor coolant temperature. The effect on the measurement is negated by using three hot leg sampling scoops per loop. One dual element RTD is mounted in a thermowell in each of the three sampling scoops associated with each hot leg.

The scoops extend into the flow stream at locations 120° apart in the cross sectional plane. Each scoop has five orifices which sample the hot leg flow along the leading edge of the scoop. Outlet ports are in the scoops to direct the sampled fluid past the sensing element of the RTDs. One of each of the RTD's dual elements is used while the other is an installed spare. Three readings from each hot leg are averaged to provide a hot leg reading for that loop. Therefore, the spatial dependency is compensated by both the limited mixing in the sampling scoops and, more importantly, by the electronic averaging of the three hot leg readings per loop. Cold leg stratification, and the resulting issue of spatial dependence, is not of concern due to the mixing action of the reactor coolant pumps.

7.3.8.1.2.4 Limits, Margins, and Levels

Operational limits and setpoints are discussed in Chapter 15.0 and the Callaway Technical Specifications. DNBR margin is discussed in Section 4.4.2.2.6. Setpoint margins are discussed in the setpoint calculations.

7.3.8.1.2.5 Abnormal Events

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

a. LOCA (see Section 15.6.5)

b. Steam and feedwater breaks (see Sections 15.1.5 and 15.2.8)

c. Earthquakes (see Chapters 2.0 and 3.0)

d. Fire (see Section 9.5.1)

e. Missiles (see Section 3.5)

f. Flood (see Chapters 2.0 and 3.0)

7.3.8.1.2.6 Minimum Performance Requirements

Minimum performance requirements are as follows:

a. System response times

The ESFAS response time is defined in the TS as the interval required for the ESF equipment to be capable of performing its safety function subsequent to the time that the appropriate variable exceeds its actuation setpoint. The ESF equipment is actuated by the output of the ESFAS, which is by the operation of the dry contacts of the slave relays (600 and 700 series relays) in the output cabinets of the solid state protection system. The response times listed below include the interval of time which will elapse between the time the parameter as sensed by the sensor exceeds the nominal trip setpoint and the time the solid state protection system slave relay dry contacts are operated. These values (as listed below) are maximum allowable values consistent with the safety analyses and the Technical Specifications and were systematically verified during plant preoperational startup tests. For the overall ESF response time, refer to Table 16.3-2. In a similar manner for the overall reactor trip system instrumentation response time, refer to Table 16.3-1. These maximum delay times include all compensation and, therefore, require that any such network be aligned and operating during verification testing.

The ESFAS is capable of having response time tests routinely performed-using methods similar to those used for tests performed during the preoperational test program or following significant component changes.

Maximum allowable time delays in generating the actuation signal for loss-of-coolant protection are:

1. Pressurizer pressure 2.0 seconds

Maximum allowable time delays in generating the actuation signal for steam line break protection are:

1.	Steam line pressure	2.0 seconds
2.	Steam line pressure rate	2.0 seconds
3.	High - 2 containment pressure for closing main steam line isolation valves	2.0 seconds
4.	Actuation signals for auxiliary feedwater pumps	See Table 16.3-2

b. System Accuracies

Accuracies required for generating the required actuation signals for loss-of-coolant protection are:

1.	Pressurizer pressure (uncompensated)	See Table 7.2-3 and Section 15.0.3.2 and approved setpoint calculations.

Accuracies required in generating the required actuation signals for steam line break protection are given:

1.	Steam line pressure	See CSA in Callaway Setpoint Methodology Report and approved calculations.
2.	Containment pressure signal	See CSA in Callaway Setpoint Methodology Report and approved calculations.

c. Ranges of sensed variables to be accommodated until conclusion of protective action is ensured.

Ranges required in generating the required actuation signals for loss-of-coolant protection are given:

1.	Pressurizer pressure	1,700 to 2,500 psig
2.	Containment pressure	0 to 69 psig

Ranges required in generating the required actuation signals for steam line break protection are given:

1.	T_{avg}	530 to 630°F
2.	Steam line pressure	0 to 1,300 psig
3.	Containment pressure	0 to 69 psig

7.3.8.1.2.7 Bistable Trip Setpoints

There are three values applicable to engineered safety feature actuation:

a. Safety analysis limit

b. Allowable value

c. Nominal trip setpoint

The safety analysis limit is the value assumed in the accident analysis.

The nominal trip setpoint is the value set into the equipment and is obtained by adding or subtracting the channel statistical allowance to/from the safety analysis limit. The nominal trip setpoint allows for the normal expected rack drift, such that the Callaway Technical Specification allowable values will not be exceeded under normal operation.

The allowable value is in the Callaway Technical Specifications and is obtained by adding or subtracting a calculated allowance to/from the nominal trip setpoint. This calculated allowance accounts for the function-specific allowances discussed in the Bases for Technical Specifications 3.3.1 and 3.3.2.

Westinghouse setpoint studies performed for the replacement steam generators (RSGs) provide an allowance from the nominal trip setpoint to the technical specification allowable value to account only for rack calibration accuracy. The difference between the nominal trip setpoints for reactor trips and ESF actuations started by SG water level low-low, SG water level high-high, and low steamline pressure and their safety analysis limits includes the same error terms discussed in Appendix 3A, RG 1-105. The “Nominal Trip Setpoints and Allowable Values” section in the Background Bases for Technical Specifications 3.3.1 and 3.3.2 discuss some differences between the pre-RSG and post-RSG setpoint methodologies, but the major difference is the tightening of the band between the NTS and the AV for the above RTS and ESFAS functions. Designers choose setpoints, such that the accuracy of the instrument is adequate to meet the assumptions of the safety analysis.

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

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

Range selection for the instrumentation covers the expected range of the process variable being monitored, consistent with its application. The design of the reactor protection and engineered safety features systems is such that the bistable trip setpoints do not require process transmitters to operate within 5 percent of the high and low end of their calibrated span or range. Functional requirements established for every channel in the reactor protection and engineered safety feature systems stipulate the maximum allowable errors on accuracy, linearity, and reproducibility. The protection channels have the capability for and are tested to ascertain that the characteristics throughout the entire span, in all aspects, are acceptable and meet functional requirement specifications. As a result, no protection channel operates normally within 5 percent of the limits of its specified span.

The specific functional requirements for response time, setpoint, and operating span are based on the results and evaluation of safety studies carried out using data pertinent to the plant. This establishes adequate performance requirements under both normal and faulted conditions, including consideration of process transmitter margins such that even under a highly improbable situation of full power operation at the limits of the operating map [as defined by the high and low pressure reactor trip, ΔT overpower and overtemperature trip lines (DNB protection), and the steam generator safety valve pressure setpoint] adequate instrument response is available to ensure plant safety.

7.3.8.1.3 Final System Drawings

The schematic diagram for the systems discussed in this section is listed in Section 1.7.

7.3.8.2 <u>Analysis</u>

a. Conformance to GDCs

Conformance to GDCs is described in Section 7.1.

b. Conformance to IEEE 279-1971

1. Single Failure Criteria

The discussion presented in Section 7.2.2.2.3 (including References 4-7 in Section 7.3.9) is applicable to the engineered safety feature actuation system, with the following exception.

In the engineered safety feature, a loss of instrument power will call for actuation of engineered safety feature equipment controlled by the specific bistable that lost power (containment spray exempted). The actuated equipment must have power to comply. The power supply for the protection system is discussed in Sections 7.6 and 8.3.

For containment spray, the final bistables are energized to trip to avoid spurious actuation. In addition, manual containment spray requires a simultaneous actuation of two manual controls. This is considered acceptable because spray actuation on hi-hi containment pressure signal provides automatic initiation of the system via protection channels meeting the criteria in Reference 3. Moreover, two sets (two switches per set) of containment spray manual initiation switches are provided to meet the requirements of IEEE Standard 279-1971. Also it is possible for all engineered safety feature equipment (valves, pumps, etc.) to be individually manually actuated from the control board. Hence, a third mode of containment spray initiation is available. The design meets the requirements of GDCs 21 and 23.

2. Equipment Qualification

   Equipment qualifications are discussed in Sections 3.10(N) and 3.11(N).

3. Channel Independence

   The discussion presented in Section 7.2.2.2.3 is applicable. The engineered safety feature slave relay outputs from the solid state logic protection cabinets are redundant, and the actuation signals associated with each train are energized up to and including the final actuators by the separate ac power supplied which powers the logic trains.

4. Control and Protection System Interaction

   The discussions presented in Section 7.2.2.2.3 are applicable.

5. Capability for Sensor Checks and Equipment Test and Calibration

The discussions of system testability in Section 7.2.2.2.3 are applicable to the sensors, analog circuitry, and logic trains of the ESFAS.

The following discussions cover those areas in which the testing provisions differ from those for the reactor trip system.

Testing of ESFAS

To facilitate engineered safety feature actuation testing, four cabinets (two per train) are provided which enable operation, to the maximum practical extent, of safety feature loads on a group-by-group basis until actuation of all devices has been checked.

The testing program meets the requirements of GDCs 21, 37, 40, and 43 and Regulatory Guide 1.22, as discussed in Section 7.1.2.5.2. The tests described in item 3 above and further discussed in Section 6.3.4 meet the requirements on testing of the emergency core cooling system, as stated in GDC-37, except for the operation of those components that will cause an actual safety injection. The test, as described, demonstrates the performance of the full operational sequence that brings the system into operation, the transfer between normal and emergency power sources, and the operation of associated cooling water systems. The safety injection and residual heat removal pumps are started and operated and their performance verified in a separate test described in Section 6.3.4. When the pump tests are considered in conjunction with the emergency core cooling system test, the requirements of GDC-37 on testing of the emergency core cooling system are met as closely as possible without causing an actual safety injection.

The system design, as described in Sections 6.3 and 7.2.2.2.3 item 3 above, provides complete periodic testability during reactor operation of all logic and components associated with the emergency core cooling system. This design meets the requirements of Regulatory Guide 1.22, as discussed in the above sections. The testing capability is as follows:

(a) Prior to initial plant operations, ESFS tests are conducted.

(b) Subsequent to initial startup, ESFS tests are conducted during each regularly scheduled refueling outage.

(c) During on-line operation of the reactor, all of the engineered safety feature analog and logic circuitry can be fully tested.

In addition, essentially all of the engineered safety feature final actuators can be fully tested. The remaining few final actuators whose operation is not compatible with continued on-line plant operation can be checked by means of continuity testing.

(d) During normal operation, the operability of testable final actuation devices of the ESFS can be tested by manual initiation from the control room.

Performance Test Acceptability Standard for the SIS and for the Automatic Demand Signal for CSAS Generation

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

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

Maintenance checks (performed during regularly scheduled refueling outages), such as resistance to ground of signal cables in radiation environments, are based on qualification test data which identifies what constitutes acceptable radiation, thermal, etc., degradation.

Frequency of Performance of Engineered Safety Feature Actuation Tests

During reactor operation, complete system testing (excluding sensors or those devices whose operation would cause plant upset) is performed periodically, as specified in the Callaway Technical Specifications. Testing, including the sensors, is also performed during scheduled plant shutdown for refueling. See the Callaway Technical Specifications for frequency of testing.

Engineered Safety Feature Actuation Test Description

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

(a) The test procedures must not involve the potential for damage to any plant equipment.

(b) The test procedures must minimize the potential for accidental tripping.

(c) The provisions for on-line testing must minimize complication of engineered safety feature actuation circuits so that their reliability is not degraded.

Description of Initiation Circuitry

Several systems comprise the total engineered safety feature system, the majority of which may be initiated by different process conditions and be reset independently of each other.

The remaining functions (listed in item h of Section 7.3.8.1.1) are initiated by a common signal (safety injection) which in turn may be generated by different process conditions.

In addition, operation of all other vital auxiliary support systems, such as auxiliary feedwater, component cooling, and service water, is initiated by the safety injection signal.

Each function is actuated by a logic circuit which is separated between each of the two redundant trains of the engineered safety feature initiation circuits.

The output of each of the initiation circuits consists of a master relay which drives slave relays for contact multiplication as required. The

logic, master, and slave relays are mounted in the solid state logic protection cabinets designated train A and train B, respectively, for the redundant counterparts. The master and slave relay circuits operate various pump and fan circuit breakers or starters, motor-operated valve contactors, solenoid-operated valves, emergency generator starting, etc.

Analog Testing

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

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

Solid State Logic Testing

Except for containment spray channels, solid state logic testing is the same as that discussed in Section 7.2.2.2.3. During logic testing of one train, the other train can initiate the required engineered safety feature function. For additional details, see References 2, 5, 6, and 7.

Actuator Testing

At this point, testing of the initiation circuits through operation of the master relay and its contacts to the coils of the slave relays has been accomplished. The engineered safety feature logic slave relays in the solid state protection system output cabinets are subjected to coil continuity tests by the output relay tester in the solid state protection system cabinets. Slave relays (K601, K602, etc.) do not operate because of reduced voltage applied to their coils by the mode selector switch (TEST/OPERATE). A multiple position master relay selector switch selects the master relays and corresponding slave relays to which the coil continuity test voltage is applied.

The master relay selector switch is returned to OFF before the mode selector switch is placed back in the OPERATE mode. However, failure to do so will not result in defeat of the protective function. The engineered safety feature actuation system slave relays are activated during the testing by the on-line test cabinet, so that overlap testing is maintained.

The engineered safety feature actuation system final actuation device or actuated equipment testing is performed from the solid

state protection test cabinets. These cabinets are located near the solid state logic protection system equipment. There is one set of test cabinets provided for each of the two protection trains, A and B. Each set of cabinets contains individual test switches necessary to actuate the slave relays. To prevent accidental actuation, test switches are of the type that must be rotated and then depressed to operate the slave relays. Assignments of contacts of the slave relays for actuation of various final devices or actuators have been made such that groups of devices or actuated equipment can be operated individually during plant operation without causing plant upset or equipment damage. In the unlikely event that a safety injection signal is initiated during the test of the final device that is actuated by this test, the device will already be in its proper position to perform its safety function.

During this last procedure, close communication is maintained between the main control room operator and the tester at the test cabinet. Prior to the energizing of a slave relay, the operator in the main control room assures that plant conditions will permit operation of the equipment that will be actuated by the relay. After the tester has energized the slave relay, the main control room operator observes that all equipment has operated, as indicated by appropriate indicating lamps, monitor lamps, and annunciators of the control board, and records all operations. He then resets all devices and prepares for operation of the next slave relay actuated equipment.

By means of the procedure outlined above, all engineered safety feature devices actuated by engineered safety feature actuation systems initiation circuits, with the exceptions noted in Section 7.1.2.5.2 under a discussion of Regulatory Guide 1.22, are operated by the automatic circuitry.

Actuator Blocking and Continuity Test Circuits

Those few final actuation devices that cannot be designed to be actuated during plant operation (discussed in Section 7.1.2.5.2) have been assigned to slave relays for which additional test circuitry has been provided to individually block actuation of a final device upon operation of the associated slave relay during testing. Operation of these slave relays, including contact operations, and continuity of the electrical circuits associated with the final devices control are checked in lieu of actual operation. The circuits provide for monitoring of the slave relay contacts, the devices' control circuit cabling, control voltage, and the devices' actuation solenoids. Interlocking prevents blocking the output from more than one output

relay in a protection train at a time. Interlocking between trains is also provided to prevent continuity testing in both trains simultaneously. Therefore, the redundant device associated with the protection train not under test will be available in the event protection action is required. If an accident occurs during testing, the automatic actuation circuitry will override testing, as noted above. One exception to this is that if the accident occurs while testing a slave relay whose output must be blocked, those few final actuation devices associated with this slave relay will not be actuated; however, the redundant devices in the other train would be operational and would perform the required safety function. Actuation devices to be blocked are identified in Section 7.1.2.5.2.

The continuity test circuits for these components that cannot be actuated on-line are verified by proving lights on the safeguards test racks.

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

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

Detail B shows the circuit for contact opening for protection function actuation. Under normal plant operation, and equipment not under test for 125-volt dc actuation devices, the white test lamps "DS*" for the various circuits will be energized, and green test lamp "DS*" will be deenergized. Typical circuit path for white lamp "DS*" will be

through the normally closed solid state logic output relay contact "K*" and through test lamp connections 3 to 1. Coil "Y2" will be capable of being deenergized for protection function actuation upon opening of solid state logic output relay contact "K*." Coil "Y2" is typical for a solenoid valve coil, auxiliary relay, etc. When the contact "K8*" is closed to block deenergizing of coil "Y2," the green test lamp is energized, and the slave relay "K*" may be energized to verify operation (opening of its contacts). To verify operability of the blocking relay in both blocking and restoring normal service, close the blocking relay contact to the green lamp - the green test lamp should now be energized also; open this blocking relay contact - the green test lamp should be deenergized, which verifies that the circuit is now in its normal, i.e., operable position.

<u>Time Required for Testing</u>

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

<u>Summary of On-Line Testing Capabilities</u>

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

The procedures require testing at various locations.

(a) Analog testing and verification of bistable setpoint are accomplished at process analog racks. Verification of

bistable relay operation is done at the main control room status lights.

(b) Logic testing through operation of the master relays and low voltage application to slave relays is done at the solid state protection system logic rack test panel.

(c) Testing of pumps, fans, and valves is done at the test panel located in the vicinity of the solid state protection system logic racks in combination with the control room operator.

(d) Continuity testing for those circuits that cannot be operated is done at the same test panel mentioned in item c above.

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

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

Testing During Shutdown

Emergency core cooling system tests will be performed periodically as stated in the Callaway Technical Specifications, with the reactor coolant system isolated from the emergency core cooling system by closing the appropriate valves. A test safety injection signal will then be applied to initiate operation of active components (pumps and valves) of the emergency core cooling system. This is in compliance with GDC-37.

Containment spray system tests will be performed at each major fuel reloading. The tests will be performed with the isolation valves in the spray supply lines at the containment blocked closed and are initiated by tripping the normal actuation instrumentation.

Periodic Maintenance Inspections

The maintenance procedures which follow will be accomplished per applicable plant procedures. The frequency will depend on the operating conditions and requirements of the reactor power plant. If any degradation of equipment operation is noted, either

mechanically or electrically, remedial action is taken to repair, replace, or readjust the equipment. Optimum operating performance must be achieved at all times.

Typical maintenance procedures include the following:

(a) Check cleanliness of all exterior and interior surfaces.

(b) Check all fuses for corrosion.

(c) Inspect for loose or broken control knobs and burned out indicator lamps.

(d) Inspect for moisture and condition of cables and wiring.

(e) Mechanically check all connectors and terminal boards for looseness, poor connections, or corrosion.

(f) Inspect the components of each assembly for signs of overheating or component deterioration.

(g) Perform complete system operating check.

The balance of the requirements listed in IEEE 279-1971 (Sections 4.11 through 4.22) is discussed in Section 7.2.2.2.3. Section 4.20 receives special attention in Section 7.5.

6. Manual Resets and Blocking Features

The manual reset feature associated with containment spray actuation is provided in the standard design of the Westinghouse solid state protection system design for two basic purposes: first, the feature permits the operator to start an interruption procedure of automatic containment spray in the event of false initiation of an actuate signal; second, although spray system performance is automatic, the reset feature enables the operator to start a manual takeover of the system to handle unexpected events which can be better dealt with by operator appraisal of changing conditions following an accident.

Manual control of the spray system does not occur once actuation has begun by just resetting the associated logic devices alone. Components will seal in (latch) so that removal of the actuate signal, in itself, will neither cancel or prevent completion of protective action, nor provide the operator with manual override of the automatic system by this single action. In order to take complete

control of the system to interrupt its automatic performance, the operator must deliberately unlatch relays which have "sealed in" the initial actuate signals in the associated motor control center, in addition to tripping the pump motor circuit breakers, if stopping the pumps is desirable or necessary.

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

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

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

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

The P-4/Low T_{avg} bypass switch does not have to meet Section 4.12 of IEEE 279-1971 since this feedwater isolation circuitry does not provide a protective function.

7. Manual Initiation of Protective Actions

There are two system level switches. Each switch actuates all four main steam line isolation and bypass valves of the system level. Automatic initiation of switchover to recirculation with manual completion is in compliance with Section 4.17 of IEEE Standard 279-1971, with the following comment.

Manual initiation of either one of two redundant safety injection actuation main control board mounted switches provides for actuation of the components required for reactor protection and mitigation of adverse consequences of the postulated accident, including delayed actuation of sequenced started emergency electrical loads as well as components providing switchover from the safety injection mode to the cold leg recirculation mode following a loss of primary coolant accident. Therefore, once safety injection is initiated, those components of the emergency core cooling system (see Section 6.3) which are realigned as part of the semiautomatic switchover go to completion on low refueling storage tank water level without any manual action.

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

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

c. Conformance to regulatory guides and associated IEEE standards

Conformance to regulatory guides and associated IEEE standards is provided in Sections 7.1.2.5 and 7.1.2.6.

d. Failure mode and effects analyses

Failure mode and effects analyses have been performed on the engineered safety feature systems' equipment, and the results are provided in Reference 3. The interface criteria provided in Appendices B and C of Reference 3 have been met in the design. A separate, yet similar, failure modes and effects analysis has been performed for the P-4/Low T_{avg} bypass switch with acceptable results.

The discussions presented in Section 7.2.2.1 are also applicable to the NSSS ESFAS. (See also References 4-7 in Section 7.3.9.)

In addition to the consideration given in this reference a loss of instrument air or loss of component cooling water to vital equipment has been considered. Neither the loss of instrument air nor the loss of cooling water (assuming no other accident conditions) can cause safety limits, as given in the Callaway Technical Specifications, to be exceeded. Likewise, loss of either of the two will not adversely affect the core or the reactor coolant system nor will it prevent an orderly shutdown if this is necessary. Furthermore, all pneumatically operated valves and controls will assume a preferred operating position upon loss of instrument air. It is also noted that, for conservatism during the accident analysis (Chapter 15.0), credit is not taken for the instrument air systems nor for any control system benefit.

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

The initiation and operation of the auxiliary feedwater system are described in the Callaway Technical Specifications.

e. Periodic testing

Periodic testing is described in Section 7.3.8.2b. Testing frequency is provided in the Callaway Technical Specifications.

7.3.8.3 Summary

The effectiveness of the engineered safety feature actuation system is evaluated in Chapter 15.0, based on the ability of the system to contain the effects of Condition III and IV events, including loss-of-coolant and steam line break accidents. The engineered safety feature actuation system parameters are based upon the component performance specifications which are given by the manufacturer or verified by test for each component. Appropriate factors to account for uncertainties in the data are factored into the constants characterizing the system.

The ESFAS must detect Condition III and IV events and generate signals which actuate the engineered safety features. The system must sense the accident condition and generate the signal actuating the protection function reliably and within a time determined by and consistent with the accident analyses in Chapter 15.0.

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

Operating procedures require that the complete engineered safety feature actuation system normally be operable. However, redundancy of system components is such that the system operability assumed for the safety analyses can still be met with certain instrumentation channels out of service. Channels that are out of service are to be placed in the tripped mode or bypass mode in the case of containment spray.

7.3.8.3.1 Loss-of-Coolant Protection

By analysis of LOCA and in system tests, it has been verified that, except for very small coolant system breaks which can be protected against by the charging pumps followed by an orderly shutdown, the effects of various LOCAs are reliably detected by the low pressurizer pressure signal; the emergency core cooling system is actuated in time to prevent or limit core damage.

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

High containment pressure also actuates the emergency core cooling system. Therefore, emergency core cooling actuation can be brought about by sensing this other direct consequence of a primary system break; that is, the engineered safety feature actuation system detects the leakage of the coolant into the containment. The generation time of the actuation signal of 2.0 seconds, after detection of the consequences of the accident, is adequate.

Containment spray will provide additional emergency cooling of containment and also limit fission product release upon sensing elevated containment pressure (Hi-3) to mitigate the effects of a LOCA.

The delay time between detection of the accident condition and the generation of the actuation signal for these systems is within the limits provided in Table 16.3-2, well within the capability of the protection system equipment. However, this time is short compared to that required for startup of the fluid systems.

The analyses in Chapter 15.0 show that the diverse methods of detecting the accident condition and the time for generation of the signals by the protection systems are adequate to provide reliable and timely protection against the effects of loss of coolant.

7.3.8.3.2 Steam Line Break Protection

The emergency core cooling system is also actuated in order to protect against a steam line break. A response time of 2.0 seconds is assumed to elapse between sensing low steam line pressure (as well as high steam pressure rate) and generation of the actuation signal. Analysis of steam line break accidents, assuming this delay for signal generation, shows that the emergency core cooling system is actuated for a steam line break in time to limit or prevent further core damage for steam line break cases.

Additional protection against the effects of steam line break is provided by feedwater isolation which occurs upon actuation of the emergency core cooling system. Feedwater line isolation is initiated in order to prevent excessive cooldown of the reactor vessel, protect the reactor coolant system boundary, and limit the containment pressure.

Additional protection against a steam line break accident is provided by closure of all steam line isolation valves in order to prevent uncontrolled blowdown of all steam generators. The generation of the protection system signal (2.0 seconds) is again short, compared to the time to trip the fast-acting steam line isolation valves. The steam line isolation valve closure time is system pressure dependent. The closure time curve for the steam line isolation valves is located in the Technical Specification Bases.

In addition to actuation of the engineered safety features, the effect of a steam line break accident also generates a signal resulting in a reactor trip on overpower or following emergency core cooling system actuation. However, the core reactivity is further reduced by the highly borated water injected by the emergency core cooling system.

The analyses in Chapter 15.0 of the steam line break accidents and an evaluation of the protection system instrumentation and channel design show that the engineered safety feature actuation systems are effective in preventing or mitigating the effects of a steam line break accident.

7.3.9 REFERENCES

1. Reid, J. B., "Process Instrumentation for Westinghouse Nuclear Steam Supply System (4 Loop Plant Using WCID 7300 Series Process Instrumentation)," WCAP-7913, January 1973. (Additional background information only)

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

3. Mesmeringer, J.C., "Failure Mode and Effects Analysis (FMEA) of the Engineered Safety Features Actuation System," WCAP-8584, Revision 1 (Proprietary) and WCAP-8760, Revision 1 (Non-Proprietary), February 1980.

4. Gangloff, W. C. and Loftus, W. D., "An Evaluation of Solid State Logic Reactor Protection in Anticipated Transients," WCAP-7706-L (Proprietary) and WCAP-7706 (Non-Proprietary), July 1971.

5. Gruber, T. J. and Harbaugh, T. D., “Westinghouse SSPS Universal Logic Board Replacement Summary Report 6D30225G01/G02/G03/G04,” WCAP-16769-P, Revision 2, February, 2011.

6. Harbaugh, T. D. and Hines, E. F., “Westinghouse SSPS Safeguards Driver Board Replacement Summary Report 6D30252G01/G02,” WCAP-16770-P, Revision 0, August, 2008.

7. Gruber, T. J. and Harbaugh, T. D., “Westinghouse SSPS Undervoltage Driver Board Replacement Summary Report 6D30350G01/G02,”WCAP-16771-P, Revision 1, April, 2011.

TABLE 7.3-1 CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEM ACTUATED EQUIPMENT LIST

Description	Actuating Channel 1	Actuating Channel 4
Ctmt H_2 Purge Inside Valve	X	
Ctmt H_2 Purge Outside Valve		X
Ctmt H_2 Sample 1 Delivery Inside Valves	X	
Ctmt H_2 Sample 2 Delivery Inside Valves		X
Ctmt H_2 Sample 1 Delivery Outside Valve	X	
Ctmt H_2 Sample 2 Delivery Outside Valve		X
Ctmt Sample 1 Return Valve	X	
Ctmt H_2 Sample 2 Return Valve		X
Ctmt H_2 Mixing Fan 1	X	
Ctmt H_2 Mixing Fan 2		X
Ctmt H_2 Mixing Fan 3	X	
Ctmt H_2 Mixing Fan 4		X
Emergency Exhaust Fans	X	X
Ctmt H_2 Thermal Recombiner 1	X	
Ctmt Thermal Recombiner 2		X

Key: Ctmt = Containment

Additional details are provided on the electrical schematic diagrams and the control logic diagrams referenced in Section 1.7.

TABLE 7.3-2 CONTAINMENT COMBUSTIBLE GAS CONTROL SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Failure	Effect on System	Detection	Remarks
Loss of one ac power channel control	Loss of redundancy	Immediate - indicator lights	Remaining channel fully operable
Loss of one dc power channel control	Spurious valve closure	Immediate - indicator lights	Remaining channel fully operable
Control switch OPEN or wiring failure SHORT	Loss of redundancy Spurious operation may occur	Periodic testing or spurious operation	Loss of control from main control room
Loss of instrument air system	No effect		There are no air-operated components in this system

TABLE 7.3-3 CONTAINMENT PURGE ISOLATION SYSTEM ACTUATED EQUIPMENT LIST

Description	Actuating Channel 1	Actuating Channel 4
Ctmt Shutdown Purge Supply Valve Inside	X	
Ctmt Shutdown Purge Supply Valve Outside		X
Ctmt Shutdown Purge Exhaust Valve Inside		X
Ctmt Shutdown Purge Exhaust Valve Outside	X	
Ctmt Shutdown Purge Supply Fan and Damper	Nonsafety	
Ctmt Shutdown Purge Exhaust Fan and Damper	Nonsafety	
Ctmt Mini-purge Supply Valve Inside	X	
Ctmt Mini-purge Supply Valve Outside		X
Ctmt Mini-purge Exhaust Valve Inside		X
Ctmt Mini-purge Exhaust Valve Outside	X	
Ctmt Mini-purge Supply Fan and Damper	Nonsafety	
Ctmt Mini-purge Exhaust Fan and Damper	Nonsafety	

Key: Ctmt = Containment

Additional details are provided on the electrical schematic diagrams and the control logic diagrams referenced in Section 1.7.

TABLE 7.3-4 CONTAINMENT PURGE ISOLATION SYSTEM FAILURE MODES AND EFFECTS ANALYSIS*

Failure Mode		Effect on System	Detection	Remarks
Loss of one ac power channel		No effect	Immediate-annunciator	Air-operated valves are controlled by dc solenoids
Loss of one dc power channel		System isolates	Immediate-annunciation on loss of bus. Periodic test on individual device level	Trip - isolates
Loss of instrument air system		Purge valves fail closed	Immediate-indicator lights and annunciation	Valves fail in safe position
Radiation sensor fails:	(a) HI (b) LO	(a) System isolates (b) 1 channel remains operable	(a) Immediate-annunciator (b) Immediate-computer or periodic testing	(a) Trip - isolates (b) See Note 1
Sensor wiring fails open or shorts		1 channel remains operable	Immediate-computer or periodic testing	See Note 1
Bistable fails		System loses one channel or trips	Periodic testing	Either trip or detected by periodic testing
CIS input open		Loss of one sensing parameter in one channel	Periodic testing	Diverse inputs (radiation, manual) fully operable
CIS input shorted		Spurious trip	Immediate-annunciator	Spurious closure; however, valves are normally closed
Manual input open		Loss of system level manual initiation in one train	Periodic testing	Redundant train and automatic actuation and device level control fully operable on affected train
Manual input shorted		Spurious trip	Immediate-annunciator	Spurious closure; however, valves are normally closed
Output relay coil open or shorted		No automatic actuation of associated devices in one train only.	Periodic testing (open); Immediate-annunciator (shorted)	Manual control not impaired, other train will isolate.
Output relay mechanically jammed		No automatic actuation of associated devices in one train only	Periodic testing	Manual control not impaired, other train will isolate
Output wiring fails:	(a) OPEN	Loss of redundancy	Periodic testing	Redundant train will still be operable
	(b) SHORT	May produce spurious isolation	Periodic testing or spurious isolation	Spurious isolation

NOTE 1: Channel failure alarm operates for failures between the radiation detector and the microprocessor. Periodic testing detects failures between the microprocessor and ESFAS cabinets.

* For plant conditions during CORE ALTERATIONS and during movement of irradiated fuel within containment, the function of the monitors is to alarm only and the trip signals for automatic actuation of CPIS may be bypassed. One instrumentation channel at a minimum is required for the alarm only function during plant refueling activities.

TABLE 7.3-5 FUEL BUILDING VENTILATION ISOLATION SYSTEM ACTUATED EQUIPMENT LIST

Description	Actuating Channel 1	Actuating Channel 4
Fuel Building Exhaust Fan A	X	
Fuel Building Exhaust Fan B		X
Outside Air Supply Isolation Damper*	X	
Outside Air Supply Isolation Damper*		X
Fuel Building Supply Fan A**	Nonsafety	
Fuel Building Supply Fan B**	Nonsafety	
Emergency Filter Supply Isolation (A)	X	
Emergency Filter Supply Isolation (B)		X
Spent Fuel Pool Exhaust Isolation (A)	X	
Spent Fuel Pool Exhaust Isolation (B)		X

Additional details are provided on the electrical schematic diagrams and the control logic diagrams referenced in Section 1.7.

* These two dampers are in series.

** Normally operating; trip on FBVIS.

TABLE 7.3-6 FUEL BUILDING VENTILATION ISOLATION SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Failure Mode		Effect on System	Detection	Remarks
Loss of one ac power channel		Loss of redundancy	Immediate-annunciator	Other channel will still be operable
Loss of one dc power channel		Disables the associated actuation channel	Immediate-annunciation of loss of bus. Periodic test on individual device level	Reduces system to minimum sufficiency
Loss of instrument air system		None - not applicable	Not applicable	Vent dampers are electricically operated
Radiation sensor fails	HI	System isolates	Immediate-annunciator	Trip-isolates
	LO	1 channel remains operable	Immediate-computer or periodic testing	See Note 1
Sensor wiring fails open or short		1 channel remains operable	Immediate-computer or periodic testing	See Note 1
Bistable fails		System either isolates or loses one channel	Periodic testing	Either trip or detected by periodic testing
Manual input open		Loss of system level manual initiation for one train	Periodic testing	Redundant train and automatic actuation and device level control fully operable on affected train.
Manual input shorted		Spurious trip	Immediate-annunciator	Spurious isolation
Output relay coil open or shorted		No automatic actuation of associated devices in one train only	Periodic testing (open); Immediate-annunciator (Shorted)	Manual control and redundant train are not impaired.
Output relay mechanically jammed		No automatic actuation of associated devices in one train only	Periodic testing	Manual control and redundant train are not impaired
Output wiring fails	OPEN	Loss of redundancy	Periodic testing	Redundant train will still be operable.
	SHORT	May produce spurious isolation	Periodic testing or spurious isolation	Spurious isolation

NOTE 1: Channel failure alarm operates for failures between the radiation detector and the microprocessor. Periodic testing detects failures between the microprocessor and ESFAS cabinets. System is reduced to minimum sufficiency.

TABLE 7.3-7 CONTROL ROOM VENTILATION ISOLATION CONTROL SYSTEM MONITOR SENSITIVITIES AND RESPONSE TIMES

Type	Minimum Concentration Requiring Isolation μCi/cc	Limiting Isotope	Response Time
Gaseous	See Tables 11.5-3 and 12.3-3	Xe^{133}	Less than 5 seconds

TABLE 7.3-8 CONTROL ROOM VENTILATION ISOLATION CONTROL SYSTEM

I. ACTUATED EQUIPMENT LIST

Description	Actuation Channel Number
Control Room Filtration System A Dampers	1
Control Room Filtration System B Dampers	4
Upper Cable Spreading Room Ventilation Isolation (2 dampers)	4
Control Room A/C Unit A	1
Control Room A/C Unit B	4
Control Room Ventilation Isolation (2 dampers)	4
Lower Cable Spreading Room Ventilation Isolation (2 dampers)	1
Control Building Outside Air Supply Unit	*
Control Building Exhaust Fan A	*
Control Building Exhaust Fan B	*
Access Control Exhaust Fan A	*
Access Control Exhaust Fan B	*
Control Building Outside Air System Isolation (5 dampers)	1 & 4
Swgr and Battery Room Ventilation Isolation (2 dampers)	4
ESF SWGR Rm Ventilation Isolation (2 dampers)	4
Access Control Area Ventilation Isolation (3 dampers)	4
Control Room Pressurization System A	1
Control Room Pressurization System B	4
Class 1E A/C System A	1
Class 1E A/C System B	4
Control Building Exhaust System Isolation (5 dampers)	1 & 4
Control Building Access Control Exhaust System Isolation (3 dampers)	4 & 1
Hot Laboratory Ventilation Isolation (2 dampers)	1
Hot Laboratory Ventilation Isolation (2 dampers)	4
Chase and Tank Area Ventilation Isolation (2 dampers)	1
Chase and Tank Area Ventilation Isolation (2 dampers)	4
Companion Power Unit ESFAS, CRVIS (where applicable)	1
Companion Power Unit ESFAS, CRVIS (where applicable)	4

Additional details are provided on the electrical schematic diagrams and the control logic diagrams references in Section 1.7. The method for achieving isolation damper redundancy is shown in Table 7.3-8, Sheet 2.

* Nonsafety related

TABLE 7.3-8 (Sheet 2)

II. CONTROL BUILDING ISOLATION DAMPERS

Channel 1 Dampers	Corresponding Channel 4 Dampers
Control Building Exhaust System	
D311 (HZ 13G)	D312 (HZ 184D)
D014 (HZ 59B)	D301 (HZ 184B)
D018 (HZ 13B)	D016 (HZ 55B)
D018 (HZ 13B)	D013 (HZ 98B)
D018 (HZ 13B)	D012 (HZ 122B)
D018 (HZ 13B)	D219 (HZ 123B)
D283 (HZ 13E)	D015 (HZ 57B)
Control Building Supply System	
D309 (HZ 13F)	D310 (HZ 184C)
D279 (HZ 13D)	D005 (HZ 57A)
D006 (HZ 59A)	D300 (HZ 184A)
D002 (HZ 13A)	D004 (HZ 55A)
D002 (HZ 13A)	D007 (HZ 98A)
D002 (HZ 13A)	D008 (HZ 122A)
D002 (HZ 13A)	D009 (HZ 123A)
D198 (HZ 172A)	D199 (HZ 173A)
Access Control Exhaust System	
D025 (HZ 13C)	D220 (HZ 123C)
D313 (HZ 13H)	D314 (HZ 184E)
D203 (HZ 172B)	D202 (HZ 173B)

TABLE 7.3-9 CONTROL ROOM VENTILATION ISOLATION SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Failure Mode		Effect on System	Detection	Remarks
Loss of one ac power channel		Loss of redundancy	Immediate-annunciator	Other channel will still be operable
Radiation sensor fails	HI	Spurious trip	Immediate-annunciator	Trip-isolates
	LO	Loss of redundancy	Immediate-computer or periodic testing	See Note 1
Sensor wiring fails open or shorts		Loss of redundancy	Immediate-computer or periodic testing	See Note 1
Bistable fails		Loss of one channel of automatic actuation or trip	Periodic testing	Either trip or detected by periodic testing
Manual input open		Loss of system level manual initiation for one train	Periodic testing	Redundant train and automatic actuation and device level control are fully operable on affected train
Manual input shorted		Spurious trip	Immediate-annunciator	Spurious isolation
Output relay coil open or shorted		No automatic actuation of associated devices in one train only	Periodic testing (open); Immediate-annunciator (shorted)	Redundant train will still be operable, also manual control available
Output relay mechanically jammed		Loss of redundancy	Periodic testing	Redundant train will still be operable, also manual control available
Output wiring fails	OPEN	Loss of redundancy	Periodic testing	Redundant train will still be operable
	SHORT	May produce spurious isolation	Periodic testing or spurious isolation	Spurious isolation
CIS input open		Loss of one sensing parameter in open channel	Periodic testing	Diverse inputs (radiation, manual) fully operable
CIS input shorted		Spurious trip	Immediate-annunciator	Spurious isolation

NOTE 1: Channel failure alarm operated for failures between the radiation detector and the microprocessor. Periodic testing detects failures between the microprocessor and ESFAS cabinets. System is reduced to minimum sufficiency.

TABLE 7.3-10 DEVICE LEVEL MANUAL OVERRIDE FAILURE MODES AND EFFECTS ANALYSIS

Failure Modes	Effect on the System	Detection	Remarks
Failure of bypass relays:			
a. Bypass relay fails to actuate	a. Loss of bypass function	a. Periodic slave relay testing (SJ system valves only) Undetectable (GS system valves only). The bypass function is not a “protective action,” so detection is not required	a. No loss of automatic protective function
b. Bypass relay fails to de-actuate	b. Blocks automatic protective function in one train	b. Periodic slave relay testing	b. Redundant train will operate except for H_2 Analyzer Iso valves H_2 Analyzer Iso valves are maintained normally closed
c. Interposing relay fails to actuate	c. Loss of bypass function and amber logic indication ESFAS status panel Loss of bypass function (Ctmt Atmos. Monitor Iso valves)	c. Periodic slave relay testing Undetectable (Ctmt Atmos. Monitor Iso valves). The bypass function is not a “protective action,” so detection is not required	c. No loss of automatic protective function No loss of automatic protective function
d. Interposing relay fails to de-actuate	d. Blocks automatic protective function in one train	d. Periodic slave relay testing, or Amber light on ESFAS status panel will illuminate when valve is open Periodic slave relay testing (Ctmt Atmos. Monitor Iso valves)	d. Redundant train will operate Redundant train will operate
Output wiring/opens or shorts	Loss of redundancy or may produce spurious operation	Periodic testing or immediate testing if spurious operation is indicated	Redundant channel will operate

TABLE 7.3-10 (Sheet 2)

Failure Modes	Effect on the System	Detection	Remarks
Failure of indicating light	No loss of control	Periodic testing	Function will be achieved without indication; system level bypass annunciation and indication will be provided

TABLE 7.3-11 AUXILIARY FEEDWATER SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Failure Mode	Effect on System	Detection	Remarks
Loss of one Class 1E ac power supply	Loss of one motor-driven auxiliary feed pump, associated feed control valves, and one essential service water suction valve in affected train and one in the turbine-driven pump suction	Immediate-annunciator	The redundant motor-driven auxiliary feed pump and steam-driven auxiliary feed pump are still available. The redundant suction valve in the turbine-driven pump supply is not affected.
Loss of one Class 1E dc power supply:			
Loss of Separation Group 1	Loss of control power to one motor-driven auxiliary feed pump. Two of the feed regulating valves for the turbine-driven pump fail open.	Immediate-annunciator	The redundant motor-driven auxiliary feed pump and steam-driven auxiliary feed pump are still available. The other two feed regulating valves for the turbine-driven pump function normally.
Loss of Separation Group 2	Loss of turbine-driven pump due to dc-controlled steam supply valves	Immediate-annunciator	The two motor-driven auxiliary feed pumps and associated valves remain completely functional.
Loss of Separation Group 3	No effect	--	No auxiliary feedwater components are controlled from this group.
Loss of Separation Group 4	Same as for Separation Group 1,except that it occurs to the other train	Immediate-annunciator	Same as for Separation Group 1
Loss of one Class 1E instrument power supply	Loss of one indication train loss or partial trip of one protection train	Immediate-annunciator	Redundant train(s) still available.
Loss of instrument air supply	Does not affect system function	Immediate-annunciator	Air reservoirs are utilized as a backup air supply.
Safety injection signal open	Loss of "safety injection signal" auto initiation in one channel only	Periodic testing	Does not affect manual initiation or other auto initiations.
Safety injection signal shorted	Starts motor-driven auxiliary feed pump and closes steam generator blowdown and sample valves.	Immediate-annunciator	Operator override to terminate auxiliary feedwater supply is possible after assessment of situation.
Loss of power signal open	Loss of "loss of power" auto initiation in one channel	Periodic testing	Does not affect manual initiation or other auto initiations.
Loss of power signal shorted	Starts the steam-driven auxiliary feed pump and closes steam generator blowdown and sample valves	Immediate-annunciator	Operator override to terminate auxiliary feedwater supply is possible after assessment of situation.

TABLE 7.3-11 (Sheet 2)

Failure Mode	Effect on System	Detection	Remarks
Blackout sequence signal open	Loss of blackout auto initiation in one motor-driven pump	Periodic testing	Redundant train and turbine-driven pump operate.
Blackout sequence signal shorted	Starts one motor-driven auxiliary feed pump and closes steam generator blowdown and sample valves	Immediate-annunciator	Operator override to terminate supply of auxiliary feedwater is possible after assessment of situation.
Blackout signal or safety injection signal shorted	Loss of one motor-driven pump	Periodic testing	Other motor-driven pump and turbine-driven pump will operate manual controls still operable to start affected pump.
Main feed pump trip signal open	Main feed pump trip will not initiate auxiliary feedwater	Periodic testing	Does not affect manual initiation or other auto initiations.
Main feed pump trip signal shorted	Starts motor-driven auxiliary feed pump and closes steam generator blowdown and sample valves	Immediate-annunciator	Operator override to terminate supply of auxiliary feedwater is possible after assessment of situation.
Manual control switch failure open	Loss of manual initiation of the associated function	Periodic testing	Does not affect auto initiations or manual initiation of other equipment.
Manual control switch shorted	Starts associated auxiliary feed pump and closes steam generator blowdown and sample valves	Immediate-annunciator	Operator will regulate to proper level.

TABLE 7.3-12 AUXILIARY SUPPORTING ENGINEERED SAFETY FEATURE SYSTEMS

System	Section
Component cooling water	9.2.2
Essential service water (ESW)	9.2.1.2
Containment spray	6.0, 7.3
Emergency exhaust	9.4.2
Diesel generator building ventilation	9.4.7
ESW pump house ventilation	9.4.8
Main steam	10.3
Main feedwater	10.4.7

TABLE 7.3-13 NSSS INSTRUMENTATION OPERATING CONDITION FOR ENGINEERED SAFETY FEATURES

No.	Functional Unit		No. of Channels	No. of Channels To Trip
1.	Safety Injection			
	a.	Manual	2	1
	b.	Containment pressure (Hi-1)	3	2
	c.	Low steam line pressure lead-lag compensated	12 (3/steam line)	2 in any one steam line
	d.	Pressurizer low pressure[a]	4	2
2.	Containment Spray			
	a.	Manual[b]	4	2
	b.	Containment pressure (Hi-3)	4	2

NOTES

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

(b) Manual actuation of the containment spray system requires the simultaneous operation of two separate switches, as described in Section 7.3.8.1.1. Note that this also initiates phase B containment isolation. The requirement for the simultaneous operation of two switches is desirable to prevent the inadvertent actuation of this system.

TABLE 7.3-14 NSSS INSTRUMENT OPERATING CONDITIONS FOR ISOLATION FUNCTIONS

No.	Functional Unit		No. of Channels	No. of Channels to Trip
1.	Containment Isolation			
	a.	Automatic safety injection (Phase A)	See item 1 (b) through (d) of Table 7.3-13	
	b.	Containment pressure (Phase B)	See item 2 (b) of Table 7.3-13	
	c.	Manual		
		Phase A	2	1
		Phase B	See item 2 (a) of Table 7.3-13	
2.	Steam Line Isolation			
	a.	High steam line negative pressure rate	12 (3/steam line)	2/steam line in any steam line
	b.	Containment pressure (Hi-2)	3	2
	c.	Low steam line pressure (lead-lag compensated)	12 (3/steam line)	2/steam line in any steam line
	d.	Manual	2*	1*
3.	Feedwater Line Isolation			
	a.	Safety injection	See item 1 of Table 7.3-13	
	b.	Steam generator high-high level 2/4 on any steam generator	4/loop	2/loop
	c.	Steam generator low-low level 2/4 on any steam generator	4/loop	2/loop
	d.	Reactor coolant low average temperature 2/4	1/loop	2 (Note 1)
	e.	Reactor trip	See Figure 7.2-1, Sheet 2	(Note 2)

TABLE 7.3-14 (Sheet 2)

No.	Functional Unit	No. of Channels	No. of Channels to Trip
	f. Manual	2*	1*

* Manual actuation of either switch closes all main feedwater isolation valves or all main steam isolation and bypass valves. It is also possible to operate these valves with individual switches. However, those controls are provided for normal operation only.

Note 1: The feedwater line will isolate on low T_{avg} only in conjunction with reactor trip (P-4). This feedwater isolation signal may be bypassed for normal reactor startups and shutdowns.

Note 2: The feedwater line will isolate on reactor trip in conjunction with low T_{avg} (see Note 1), high-high steam generator level, or safety injection.

TABLE 7.3-15 NSSS INTERLOCKS FOR ENGINEERED SAFETY FEATURE SYSTEM

Designation	Input	Function Performed
P-4	Reactor trip	Actuates turbine trip
		Feedwater isolation signal occurs on T_{avg} below setpoint. This feedwater isolation signal may be bypassed for normal reactor startups and shutdowns. This circuitry does not provide a required protective function.
		Prevents opening of main and bypass feedwater control valves which were closed by safety injection or high-high steam generator water level
		Allows manual block of the automatic reactuation of safety injection
	Reactor not tripped	Defeats the block preventing automatic reactuation of safety injection
P-11	2/3 pressurizer pressure below setpoint	Allows manual block of safety injection actuation on low pressurizer pressure signal
		Allows manual block of safety injection actuation and steam line isolation on low lead/lag compensated steam line pressure signal and allows steam line isolation on high steam line negative pressure rate
P14	2/4 steam generator level above setpoint in any steam generator	Closes all feedwater isolation valves, feedwater control valves. Trips both main feedwater pumps which closes the pump discharge valves. Actuates turbine trip.

7.4 SYSTEMS REQUIRED FOR SAFE SHUTDOWN

The functions necessary for safe shutdown are available from instrumentation and control channels that are associated with the major systems in both the primary and secondary plant. These channels are normally aligned to serve a variety of operational functions, including startup and shutdown, as well as protective functions. There are no systems dedicated as safe shutdown systems, per se. However, procedures for securing and maintaining the plant in a safe condition can be instituted by appropriate alignment of selected systems in the nuclear steam supply system. The discussion of these systems, together with the applicable codes, criteria, and guidelines, is found in other sections of this safety analysis report. In addition, the alignment of shutdown functions associated with the engineered safety features, which are invoked under postulated limiting fault situations, is discussed in Sections 6.3 and 7.3.

In the event of a turbine or reactor trip, loss of offsite power is assumed, and the plant will be placed in a hot standby condition. If required by a limiting condition of operation per the Callaway Technical Specifications or if recovery from an event will cause the plant to be shut down for an extended period of time, the plant will be taken to a cold shutdown (CSD) condition. During the safe shutdown condition, an adequate heat sink is provided to remove reactor core residual heat. Boration capability is provided to compensate for xenon decay and to maintain the required core shutdown margin. Redundancy of systems and components is provided to enable continued maintenance of the hot standby condition. If required, it is assumed that permanent or temporary repairs can be made to correct or circumvent any failures which might otherwise impede eventually taking the plant to the cold shutdown condition.

The instrumentation and control functions which are required to be aligned for maintaining safe shutdown of the reactor, that are discussed in this section and Appendix 5.4A, are the minimum number under nonaccident conditions. These functions will permit the necessary operations that will:

a. Prevent the reactor from achieving criticality in violation of the parameters prescribed in the Callaway Technical Specifications.

b. Provide an adequate heat sink so that design and safety limits on reactor coolant system temperature and pressure are not exceeded.

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

a. Circulation of reactor coolant

b. Boration

c. Residual heat removal

d. Depressurization

The specific systems, together with the necessary associated instrumentation and controls, are identified for both hot standby and cold shutdown in Appendix 5.4A and in Sections 7.4.1 and 7.4.2.

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

The results of the accident analyses are presented in Chapter 15.0. Of these, the following produce the consequences that are most pertinent:

a. Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant (uncontrolled boron dilution) (15.4.6)

b. Loss of normal feedwater flow (15.2.7)

c. Loss of external electrical load and/or turbine trip (15.2.2 and 15.2.3)

d. Loss of nonemergency ac power to the station auxiliaries (15.2.6)

These analyses show that safety is not adversely affected by these incidents, with the associated assumptions being that the instrumentation and controls discussed in Section 7.4.1 are available to control and/or monitor shutdown. These available systems will allow the maintenance of hot standby even under the accident conditions listed above, which would tend toward a return to criticality or a loss of heat sink.

In addition to the operation of systems required for safe shutdown, as described below, the following general considerations are applicable:

a. The turbine is tripped (note that this can be accomplished at the turbine as well as inside the control room).

b. The reactor is tripped (note that this can be accomplished at the reactor trip switchgear as well as inside the control room).

c. All automatic systems continued functioning (discussed in Sections 7.2 and 7.7).

7.4.1 HOT STANDBY

To effect a unit shutdown, the unit will be brought to, and maintained at, a safe shutdown condition under control from the main control room or the auxiliary shutdown control panel. Hot standby is defined as the condition in which the reactor is subcritical and the reactor coolant system temperature and pressure are in the normal operating range. The portions of the reactor trip system required to achieve the shutdown condition are described in Section 7.2. The system and component controls and monitoring indicators provided on the auxiliary shutdown control panel are listed in Section 7.4.3. The minimum systems/controls and monitoring indicators required to maintain a safe hot standby under the conditions discussed in note 4 of Table 3.11(B)-3, i.e. SSE and loss of offsite power, are highlighted below.

a. Essential System and Component Controls

   See Appendix 5.4A

b. Essential Monitoring Indicators

   1. Steam Generators

      (a) Water level for each steam generator

      (b) Pressure for each steam generator

   2. Pressurizer

      (a) Water level

      (b) Pressure (reactor coolant system pressure or pressurizer pressure)

   3. Auxiliary feedwater system

      (a) Suction pressure for each auxiliary feedwater pump

   4. Chemical and Volume Control System

      (a) Boric acid tank level

      (b) Safety grade, excess letdown flow to PRT

      (c) RCP seal injection flow

      (d) ECCS CCP discharge flow to the Boron Injection Header

5. Borated Refueling Water System

   (a) RWST level

6. Component Cooling Water System

   (a) Flow to components inside containment

7.4.1.1 Auxiliary Feedwater Control

The auxiliary feedwater pumps start automatically, as described in Section 7.3.6.1.1, or can be started manually. Start/stop pump controls located on the auxiliary shutdown control panel (as well as inside the control room) are provided, as well as control for the flow control valves.

7.4.1.2 Atmospheric Steam Relief

7.4.1.2.1 Description

The instrumentation and controls for the atmospheric steam relief system consist of controls, transmitters, and indicators to provide automatic or manual actuation of the power-operated atmospheric steam relief valves (also referred to as the atmospheric steam dump valves) to remove reactor heat from the reactor coolant system.

Both the safety valves and the power-operated atmospheric steam dump valves are located upstream of the main steam isolation valves, outside of the containment, and both provide a means of removing reactor heat in a hot standby condition. The safety valves are full-capacity, spring-loaded valves which are actuated by high main steam line pressure. They are described more fully in Section 10.3. The power-operated atmospheric steam dump valves, however, are the preferred mode of steam relief to avoid prolonged operation of the safety valves. The power-operated portion of the relief system is safety related, except as specifically noted otherwise in Paragraphs h and i below.

A pressure transmitter and pressure controller are provided for each of the steam generators to actuate the atmospheric steam dump valve and control the steam pressure at a predetermined setting. Manual control capability is provided in the control room, on the auxiliary shutdown control panel, and locally for AB-PV-2 and 3 for steam dump valve regulation. The status of the power-operated atmospheric steam dump valves is indicated by open and closed indicating lights and by the controller output indication.

a. Initiating circuits

   No initiating circuits are required for the self-actuated safety valves. Each atmospheric steam dump valve is automatically actuated to regulate the steam generator pressure via the pressure controller and can be manually

actuated by selecting the manual control mode. The required instrumentation readout for manual system control is described in Section 7.5.

b. Logic

No logic is required for the spring-loaded safety valves. Each atmospheric steam dump valve is individually controlled by its own pressure control loop. Normal atmospheric steam dump valve operation is the automatic mode, but, alternatively, it may be operated in a manual mode.

c. Bypass

No bypass is provided. Placement of the power-operated steam valve controller in the manual mode does not preclude the steam relief functional requirement since the safety relief valves provide a steam pressure relief capability.

d. Interlock

No interlock is provided for the atmospheric steam relief system.

e. Redundancy

Any two of the four atmospheric steam dump valves provide sufficient steam relief for hot standby requirements. Redundancy is accomplished on a system basis since any two of the four associated steam generators are adequate for the heat removal requirements.

f. Diversity

Diversity is accomplished by the spring-loaded safety valves operating as backup to the atmospheric steam dump valves.

g. Actuated devices

The safety valves are self-actuated.

The atmospheric steam dump valves are air operated, fail closed, and require a pressurized gas supply for operation.

h. Supporting systems

The controls for the atmospheric steam dump valves are powered from the Class 1E power system (Section 8.3). The pressurized gas supply required for motive force is normally supplied from the instrument air

header, which is not safety related. In addition, each valve has a seismic Category I backup gas supply, as described in Section 9.3.1.

i. Portion of system not required for safety

The alarms to the station annunciator and computer are not required for safety.

j. Design bases information

The design bases of the atmospheric steam relief system (in accordance with Section 3 of IEEE Standard 279-1971) are:

1. The generating station condition which requires protective action is hot standby heat removal at controlled steam generator pressure, with or without loss of offsite power.

2. The range of transient and steady-state conditions of both the energy supply and the environment during normal, abnormal, and accident circumstances throughout which the system must perform:

   The equipment is located outside the containment and is designed to withstand the temperature range, relative humidity, and atmospheric pressure for that location (refer to Tables 3.11(B)-1 and 3.11(B)-2 for specific values). The Class 1E power system is discussed in Section 8.3.

3. The malfunctions, accidents, or other unusual events which could physically damage protection system components for which provisions must be incorporated to retain necessary protective action:

   The atmospheric steam relief system is designed to withstand the effects of earthquake without loss of function. The system is designed and its components are physically located to prevent loss of function from missile damage.

4. Minimum performance requirements, including system response times, system accuracies, ranges of the magnitudes, and change of sensed variables to be accommodated until proper conclusion of the protective action is assured:

   The atmospheric steam relief controls are analog in nature, and the response of conventional process control equipment adjusted for stable pressure controlling operation is adequate in view of the following:

The power-operated atmospheric steam dump valves are not intended to prevent safety valve operation when the turbine bypass (steam dump to condenser) system is not available. The requirement is for the power-operated atmospheric steam dump valves to relieve the safety valves from a sustained pressure controlling function in the hot standby mode. Thus, response time and accuracy are not critical for the required performance. The steam generator pressure will be relatively constant (no load steam pressure), with no rapid change required in the mass flow rate from the atmospheric steam dump valves.

k. Drawings

Logic Diagram (refer to Section 1.7).

7.4.1.2.2 Analysis

a. Conformance to NRC general design criteria

1. General Design Criteria 13 and 19

Instrumentation necessary to monitor station variables associated with hot standby is provided with adequate indication in the main control room and on the auxiliary shutdown control panel. Controls for the atmospheric steam relief are provided at each location. A description of the surveillance instrumentation is provided in Section 7.5.

2. General Design Criterion 34

The power-operated atmospheric steam dump valves provide an adequate means of venting the steam generators to remove reactor decay heat following reactor trip. Modulation of the power-operated atmospheric steam dump valves provides the desired rate of heat removal from the reactor coolant system to maintain the hot standby condition.

The power-operated atmospheric steam dump system has sufficient redundancy to ensure its intended function, assuming a single failure.

b. Conformance to NRC regulatory guides

1. Regulatory Guide 1.22

The atmospheric steam relief controls can be tested periodically.

2. Regulatory Guide 1.29

The atmospheric steam relief controls are designed to withstand the effects of SSE without loss of function. The atmospheric steam relief controls are classified seismic Category I, in accordance with the guide.

c. Conformance to IEEE Standard 279-1971

The controls for the power-operated atmospheric steam relief system conform to the applicable requirements of IEEE Standard 279-1971. The control circuits are designed so that any single failure will not prevent proper protective action (removal of reactor decay heat) when required. This is accomplished by redundant steam relief systems in that only two of the four valves are needed to provide sufficient capacity. The atmospheric steam dump valves utilize control power from independent Class 1E power systems. The controller for each of the four valves is powered from a separate independent system. Each atmospheric steam dump valve has a separate bottled gas supply system to provide motive power. In order to prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between control channels.

d. Conformance to other criteria and standards

Conformance to other criteria and standards is indicated in Table 7.1-2.

7.4.1.3 Other Systems and Controls Required for Hot Standby

7.4.1.3.1 Description

If the unit is maintained in a hot standby condition for a prolonged time, negative reactivity must be added. The systems and controls required for this function are described in Appendix 5.4A.

7.4.1.3.2 Analysis

Conformance to the GDCs, IEEE-279-1971, applicable Regulatory Guides, and other industry standards are presented in Table 7.1-2.

7.4.2 COLD SHUTDOWN

7.4.2.1 Description

The systems and controls required for cold shutdown are described in Appendix 5.4A. The instrumentation and controls for these systems may require some authorized field

alterations in order that their functions may be performed from outside the control room. Note that the reactor plant design includes attaining the cold shutdown condition from outside the control room.

7.4.2.2 Analysis

The results of the analysis which determined the applicability to the nuclear steam supply system cold shutdown systems of the General Design Criteria, IEEE Standard 279-1971, applicable regulatory guides, and other industry standards are presented in Table 7.1-2.

7.4.3 SAFE SHUTDOWN FROM OUTSIDE THE CONTROL ROOM

Hot standby is a safe and stable plant condition for a reactor plant that incorporates a combined Westinghouse/Areva NSSS. Examination of Condition II, III, or IV events for the Westinghouse/Areva NSSS has revealed none that require cool down to cold shutdown conditions for safety reasons. Eventual achievement of cold shutdown conditions may be required for long-term recovery. However, there is no safety reason why this must be accomplished in some limited period of time. While the plant is in the hot standby condition, the auxiliary feedwater system and the steam generator safety valves or atmospheric steam dump valves can be used to remove residual heat to meet all safety requirements. The long-term safety grade supply of AFW allows extended operation at hot standby conditions. Boration, from outside of the control room, during the hot standby condition is discussed in Section 7.4.3.1.3. Additionally, nothing in the plant design precludes the eventual achievement of cold shutdown, even assuming an SSE, a loss of offsite power, and the most limiting single failure, if arbitrary restrictions are not placed on either the time required to cool down or on permissible operator actions outside the control room.

7.4.3.1 Description

If temporary evacuation of the control room is required because of some abnormal station condition, the operators can establish and maintain the station in a hot standby condition from outside the control room through the use of controls located at the auxiliary shutdown control panel, at the switchgear, or at motor control centers, and other local stations. Hot standby is a stable plant condition reached following a plant shutdown. The hot standby condition can be maintained safely for an extended period of time. In the unlikely event that access to the control room is restricted, the plant can be safely kept at a hot standby, until the control room can be reentered, by the use of the essential monitoring indicators and the controls listed in Sections 7.4.3.1.1 and 7.4.3.1.2. The auxiliary shutdown panel room is located in the northeast corner of the auxiliary building one level below the control room at Elevation 2026. There are two distinct auxiliary shutdown panels at this location; one panel is associated with instrumentation and control circuits used for controlling safe shutdown equipment in train A, and the other panel is associated with instrumentation and control circuits used for controlling safe shutdown equipment in train B. Both panels are electrically separated and are associated with the same safety-grade circuits that serve their respective trains. The

auxiliary shutdown panel design also provides electrical isolation of control and instrumentation circuits for the equipment controlled between train B auxiliary shutdown panel RP118B and the control room. Switches are provided on RP118B to isolate and remove control from the control room for the train B safe shutdown equipment necessary to take the plant to and maintain the plant in a safe hot standby condition independent of the control room. This capability is assured in the event a postulated fire causes damage in the control room and subsequent evacuation of the operators. Train B controls and instrumentation were selected to be isolated because the controls and instrumentation for the turbine-driven auxiliary feedwater pump are located on this panel. A description of the control room fire is provided in Section 9.5.1. Refer to Table 7.4-1 for the list of instrumentation and controls on RP118B that have an isolation feature.

Although the prime intent of the auxiliary shutdown control panel is the maintaining of hot standby from outside the control room, this panel can also be used for certain functions when implementing cold shutdown from outside the control room.

7.4.3.1.1 Auxiliary Shutdown Panel

The following controls and monitoring indicators are provided on the auxiliary shutdown control panel.

a. Controls

1. START/STOP control for each motor-driven auxiliary feedwater pump (1) (5) (6)

2. START/STOP controls for the turbine-driven auxiliary feedwater pump (steam supply and trip and throttle valve controls) (5) (6)

3. MANUAL control for all auxiliary feedwater flow control valves (2) (5) (7)

4. OPEN/CLOSE control for essential service water to the auxiliary feedwater pump suction valves and condensate storage tank to the auxiliary feedwater pump suction valves (1) (5) (6)

5. Auxiliary feedwater pump turbine speed control (2) (5)

6. AUTOMATIC/MANUAL control for each power-operated atmospheric steam dump valve (2) (5) (8)

7. ON/OFF/AUTO control for two pressurizer backup heater groups (3) (6)

8. OPEN/CLOSE control for the containment isolation valves in the letdown line (1) (5) (6)

9. OPEN/CLOSE control for the shutoff valves in the letdown line upstream of the regenerative heat exchanger and for the letdown throttle valve isolation valves

b. Monitoring indicators (4)

1. Water level for each steam generator (both wide range and narrow range) (5) (9)

2. Pressure for each steam generator (5)

3. Reactor coolant system pressure (wide range) (5) (10)

4. Pressurizer pressure

5. Pressurizer level (5) (11)

6. Suction pressure for each auxiliary feedwater pump (5) (12)

7. Auxiliary feedwater pump turbine speed (rpm) (5) (13)

8. Discharge pressure for each auxiliary feedwater pump

9. Auxiliary feedwater flow to each steam generator (5) (14)

10. Condensate storage tank level

11. Reactor coolant (cold leg) wide range temperature (all four loops) (15)

12. Source range nuclear power indicators (16)

13. Intermediate range nuclear power indicator

14. Wide range neutron flux indicator (5) (17)

15. Indicating lights (on-off/open-closed) for all power-operated equipment listed in a. above.

16. Reactor coolant (hot leg) wide-range temperature (two loops) (18)

An equipment list for the auxiliary shutdown panel is contained in Table 7.4-1.

NOTES:

(1) Train A paralleled with the control switch in the control room (control can be accomplished from either location without use of a transfer switch; the equipment responds to the last command from either location).

(2) Transfer of the control circuit with switch at the auxiliary shutdown panel is provided for the analog instrument control loop.

(3) "AUTO" mode is not operable after transfer.

(4) A list of monitoring instrumentation, including number of channels, is provided in Table 7.5-2.

(5) Safety-related monitoring indicator or control.

(6) Train B controls in the main control room can be isolated from the auxiliary shutdown panel controls. Control is transferred through a transfer switch located at the auxiliary shutdown panel.

(7) AL-HK-0005B, AL-ZL-0005B, AL-HK-0010B, and AL-ZL-0010B can be isolated from the main control board by RP147B.

(8) AB-PIC-0002B, AB-ZL-0002B, AB-PIC-0004B, and AB-ZL-0004B can be isolated from the main control board by RP147A, RP147B, RP334, and RP335.

(9) AE-LI-0502A and AE-LI-0504A can be isolated from the main control board by SB148A and SB148B.

(10) BB-PI-0406X can be isolated from the main control board by SB148B.

(11) BB-LI-0460B can be isolated from the main control board by SB148A.

(12) AL-PI-0026B and AL-PI-0024B can be isolated from the main control board by RP147A and RP147B.

(13) FC-HIK-0313B is fed from separation group 2 and can be isolated from the main control board by RP147A via FC-HS-0313.

(14) AL-FI-0003B and AL-FI-0001B are fed from separation groups 2 and 4 and can be isolated from the main control board by RP147A and RP147B.

(15) BB-TI-0423X is fed from separation group 4 and can be isolated from the main control board by SB148A.

(16) SE-NI-0061X is fed from separation group 4.

(17) SE-NI-0031C is fed from separation group 5 and is

(18) non-safety related.

(19) SE-NI-0061Y is fed from separation group 4.

(20) BB-TI-0443A is fed from separation group 4 and can be isolated from the main control board by SB148A.

7.4.3.1.2 Controls at Switchgear Motor Control Centers, and Other Locations

In addition to the controls and monitoring indicators listed above, the following essential controls are provided outside of the control room with a communication network between these control locations and the auxiliary shutdown control panel:

1. Reactor trip capability at the reactor trip switchgear.

2. START/STOP controls for both ECCS centrifugal charging pumps. Location: ECCS charging pump switchgear.

3. START/STOP controls for the component cooling water pumps. Location: Component cooling water pumps switchgear.

4. START/STOP controls for the containment fan cooler units. Location: Cooler fan motor control centers.

5. START/STOP controls for the control room air-conditioning units. Location: At the equipment.

6. START/STOP controls for the diesel generators. Location: Each diesel generator local control panel.

7. START/STOP controls for the essential service water pumps. Location: Essential service water pump switchgear.

7.4.3.1.3 Controls for Extended Hot Standby

In order to maintain an extended hot standby (greater than 24 hours), additional negative reactivity must be added to the RCS to accommodate the positive reactivity added through xenon decay. This can be accomplished by manual control of the normal charging and letdown systems via controls at the auxiliary shutdown panel, motor control centers, switchgears, and control of individual equipment at the device location.

However, extended hot standby conditions can be maintained from outside the control room through the use of redundant, safety-grade systems only. This is accomplished by means of the controls and indications on the auxiliary shutdown panel (ASP) and the additional controls listed in Section 7.4.3.1.2 of the FSAR. Prior to approximately 25 hours after reactor shutdown, sufficient boron would be added to the reactor coolant system (RCS) to cancel the effects of xenon decay. (See Section 5.4A.3.1)

Boration can be accomplished from outside the control room using only redundant safety-grade equipment by operating one of two ECCS centrifugal charging pumps, taking suction from the refueling water storage tank (RWST), and charging into the RCS through either the normal charging path or the boron injection flow path.

In the absence of a safety injection (SI) signal, one ECCS centrifugal charging pump would be started from its switchgear (NB01 or NB02), and isolation of normal letdown from the ASP would cause automatic realignment of pump suction from the volume control tank (VCT) to the RWST via a VCT low level signal. Charging into the RCS could be through the normal charging line, in which all air-operated valves are fail-open. An alternative charging path is the boron injection flow path. The normally closed valves in that path can be opened using local switches at motor control centers NG01B and/or NG04C.

To provide sufficient volume for the injection of additional borated water to the RCS, a reduction of RCS average temperature can be accomplished by manually controlling steam release to the atmosphere from the redundant secondary-side atmospheric relief valves. Necessary controls and instrumentation are on the ASP. Under the conditions of RCS makeup from the RWST, no letdown, and pressurizer level maintained within the normal range, sufficient boron can be added to the RCS to maintain $k_{eff} \leq 0.99$ at all temperatures between normal operating temperature and 80°F at any time in core life, assuming that the xenon concentration in the core at the time of shutdown was the equilibrium value or less. In addition, sufficient boron can be added in this manner to maintain extended hot standby conditions. Therefore, the Callaway design permits achievement of extended hot standby conditions from outside the control room by means of redundant, safety-grade systems and equipment only.

In addition to the normal charging and letdown systems, the systems discussed in Appendix 5.4A may be used to maintain an extended hot standby by local actions outside the control room.

7.4.3.1.4 Design Bases Information

In accordance with NRC General Design Criterion 19, the capability of establishing a hot standby condition and maintaining the station in a safe status in that mode is considered an essential function. To ensure the availability of the auxiliary shutdown control panel and essential control and indications after control room evacuation, the following design features have been utilized:

a. The auxiliary shutdown control panel, including all essential instrumentation mounted on it, is designed to withstand earthquakes with no loss of essential functions. The essential local control stations are also designed to withstand earthquakes with no loss of essential functions.

b. The essential local stations and the auxiliary shutdown control panel, including essential controls and indicators, are designed to comply with applicable portions of IEEE Standard 279-1971.

Certain actuations during control room evacuation in a fire event are not automatic and may require recovery actions. Specific detail on Control Room fire is discussed in FSAR Section 9.5.1.

7.4.3.2 Analysis

The analysis of the control systems required for safe shutdown is found in Section 7.4.1. The discussion below is limited to the auxiliary shutdown control panel and essential local control stations.

a. Conformance to NRC general design criteria

   1. General Design Criterion 19

      The auxiliary shutdown control panel, in conjunction with the local control stations discussed in Section 7.4.3.1, provides adequate controls and indications located outside the main control room to maintain the reactor and the reactor coolant system in the hot standby condition in the event that the main control room must be evacuated. For discussion on potential cold shutdown capability from outside the main control room, see Section 7.4.2.

b. Conformance to NRC regulatory guides

   1. Regulatory Guide 1.22

      The auxiliary shutdown control panel and the essential controls and indications are designed to be tested periodically during station operation.

   2. Regulatory Guide 1.29

      The auxiliary shutdown control panel and the essential controls and indications are designed to withstand the effects of an SSE without loss of function or physical damage. The auxiliary shutdown control panel and essential controls and indications are classified Seismic Category I.

c. Conformance to IEEE Standard 279-1971

The auxiliary shutdown control panel, and the essential controls and indications, are designed to conform to applicable portions of IEEE Standard 279-1971. The control circuits for the essential controls and indications are designed such that any single failure will not prevent proper protective action when required. This is accomplished by fully redundant controls and indications utilizing independent Class 1E power systems.

To prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between redundant control systems. Nonessential control circuits and nonessential monitor circuits are electrically isolated from essential controls and indications to prevent jeopardizing the reliability of the systems required for safe shutdown.

d. Conformance to other guides, criteria, and standards

The additional guides, criteria, and standards listed in Table 7.1-2 apply only to the essential instrumentation and controls required for hot standby from outside the control room.

TABLE 7.4-1 AUXILIARY SHUTDOWN PANEL EQUIPMENT LIST

Instrument No.	Service	Sep. Group
BB-PI-455B	Pressurizer Pressure	NV (5)
BB-LI-459B	Pressurizer Level	1
*BB-LI-460B	Pressurizer Level	4
*BB-PI-406X	RCS Pressure (wide range)	4
BB-PI-405X	RCS Pressure (wide range)	1
BB-HIS-51B	Pzr Htrs Backup Gp A	NV (5)
*BB-HIS-52B	Pzr Htrs Backup Gp B	NV (6)
AB-PI-516X	SG A Pressure	4
AB-PI-524B	SG B Pressure	1
AB-PI-535X	SG C Pressure	4
AB-PI-544B	SG D Pressure	1
AE-LI-501A	SG A Level (wide range)	1
*AE-LI-502A	SG B Level (wide range)	4
AE-LI-503A	SG C Level (wide range)	1
*AE-LI-504A	SG D Level (wide range)	4
AB-PIC-1B	SG A Stm Dump to Atmos Ctrl	1
*AB-PIC-2B	SG B Stm Dump to Atmos Ctrl	2
AB-PIC-3B	SG C Stm Dump to Atmos Ctrl	3
*AB-PIC-4B	SG D Stm Dump to Atmos Ctrl	4
AB-HS-1	SG A Stm Dump to Atmos Ctrl Xfr Sw	1
AB-HS-2	SG B Stm Dump to Atmos Ctrl Xfr Sw	2
AB-HS-3	SG C Stm Dump to Atmos Ctrl Xfr Sw	3
AB-HS-4	SG D Stm Dump to Atmos Ctrl Xfr Sw	4
AB-ZL-1B	SG A Stm Dump to Atmos Vlv Posn	1

TABLE 7.4-1 (Sheet 2)

Instrument No.	Service	Sep. Group
*AB-ZL-2B	SG B Stm Dump to Atmos Vlv Posn	2
AB-ZL-3B	SG C Stm Dump to Atmos Vlv Posn	3
*AB-ZL-4B	SG D Stm Dump to Atmos Vlv Posn	4
BG-HIS-8149AB	Letdown Throttle Valve A Isol Vlv	NV (5)
BG-HIS-8149BB	Letdown Throttle Valve B Isol Vlv	NV (5)
BG-HIS-8149CB	Letdown Throttle Valve C Isol Vlv	NV (5)
*BG-HIS-8152A	Letdown Ctmt Isol Vlv	4
BG-HIS-8160A	Letdown Ctmt Isol Vlv	1
*AL-HK-5B	SG D Aux Fw Ctrl Vlv MD Pmp B	4
AL-HS-5	SG D Aux Fw Ctrl Vlv Xfr Sw	4
*AL-ZL-5B	SG D Aux Fw Ctrl Vlv Posn	4
AL-HK-6B	SG D Aux Fw Ctrl Vlv TD Pmp	1
AL-HS-6	SG D Aux Fw Ctrl Vlv Xfr Sw	1
AL-ZL-6B	SG D Aux Fw Ctrl Vlv Posn	1
AL-HK-7B	SG A Aux Fw Ctrl Vlv MD Pmp B	4
AL-HS-7	SG A Aux Fw Ctrl Vlv Xfr Sw	4
AL-ZL-7B	SG A Aux Fw Ctrl Vlv Posn	4
AL-HK-8B	SG A Aux Fw Ctrl Vlv TD Pmp	1
AL-HS-8	SG A Aux Fw Ctrl Vlv Xfr Sw	1
AL-ZL-8B	SG A Aux Fw Ctrl Vlv Posn	1
AL-HK-9B	SG B Aux Fw Ctrl Vlv MD Pmp A	1
AL-HS-9	SG B Aux Fw Ctrl Vlv Xfr Sw	1
AL-ZL-9B	SG B Aux Fw Ctrl Vlv Posn	1
*AL-HK-10B	SG B Aux Fw Ctrl Vlv TD Pmp	4
AL-HS-10	SG B Aux Fw Ctrl Vlv Xfr Sw	4

TABLE 7.4-1 (Sheet 3)

Instrument No.	Service	Sep. Group
*AL-ZL-10B	SG B Aux Fw Ctrl Vlv Posn	4
AL-HK-11B	SG C Aux Fw Ctrl Vlv MD Pmp A	1
AL-HS-11	SG C Aux Fw Ctrl Vlv Xfr Sw	1
AL-ZL-11B	SG C Aux Fw Ctrl Vlv Posn	1
AL-HK-12B	SG C Aux Fw Ctrl Vlv TD Pmp	4
AL-HS-12	SG C Aux Fw Ctrl Vlv Xfr Sw	4
AL-ZL-12B	SG C Aux Fw Ctrl Vlv Posn	4
*AL-FI-1B	SG D Aux Fw Flow	4
AL-FI-2B	SG A Aux Fw Flow	1
*AL-FI-3B	SG B Aux Fw Flow	2
AL-FI-4B	SG C Aux Fw Flow	3
AL-PI-15B	MD Aux Fw Pmp B Disch Press	NV (6)
AL-PI-18B	MD Aux Fw Pmp A Disch Press	NV (5)
AL-PI-21B	Turb Driven Aux Fw Pmp Disch Press	NV (6)
AL-PI-25B	MD Aux Fw Pmp A Suct Press	1
*AL-PI-24B	MD Aux Fw Pmp B Suct Press	4
*AL-PI-26B	Turb Driven Aux Fw Pmp Suct Press	2
*AL-HIS-22B	MD Aux Fw Pmp B	4
AL-HIS-23B	MD Aux Fw Pmp A	1
*FCZL-312AD, AE, AF	AFPT Trip & Throt Vlv Posn	2
*FC-HIS-312B	Turb Driven Aux Fw Pmp Trip and Throt Vlv Control	2
*FC-SI-0313B *FC-HIS-0313B	AFPT Speed Gov Ctrl	2
*AB-HIS-5B	Turb Drvn Aux Fw Pmp Stm Isol Vlv	2
*AB-HIS-6B	Turb Drvn Aux Fw Pmp Stm Isol Vlv	2

TABLE 7.4-1 (Sheet 4)

Instrument No.	Service	Sep. Group
AP-LI-4B	Cond Stor Tank Level	NV (6)
*AL-HIS-30B	ESW to MD Aux Fw Pmp B	4
AL-HIS-31B	ESW to MD Aux Fw Pmp A	1
AL-HIS-32B	ESW to Turb Driven Aux Fw Pmp	1
*AL-HIS-33B	ESW to Turb Driven Aux Fw Pmp	4
*AL-HIS-34B	CST to MD Aux Fw Pmp B	4
AL-HIS-35B	CST to MD Aux Fw Pmp A	1
AL-HIS-36B	CST to Turb Driven Aux Fw Pmp	1
BB-TI-413X	W.R. RCS Cold Leg Temp Loop 1	NV (6)
*BB-TI-423X	W.R. RCS Cold Leg Temp Loop 2	4
BB-TI-433X	W.R. RCS Cold Leg Temp Loop 3	NV (5)
BB-TI-443X	W.R. RCS Cold Leg Temp Loop 4	NV (5)
SE-NI-31C	Source Range Nuclear Inst	NV (5)
*SE-NI-61X	Source Range Neutron Flux	4
AE-LI-517X	SG A Level (narrow range)	4
AE-LI-528X	SG B Level (narrow range)	1
AE-LI-537X	S.G. C Level (narrow range)	4
AE-LI-548X	S.G. D Level (narrow range)	1
BG HIS-459A	RCS Letdown to Regen Hx	NV (5)
BG HIS-460A	RCS Letdown to Regen Hx	NV (5)
FC-HS-313	AFPT Gov Ctrl Transfer Sw	2
SE-NI-35C	Intermediate Range Nuclear Inst	NV (5)
*SE-NI-61Y	Wide Range Neutron Flux	4
*FC-ZL-315B, 317B	AFPT Gov Vlv Position	2
*FCZL-312DB	AFPT Throttle Vlv Trip Mech Pos	2

TABLE 7.4-1 (Sheet 5)

Instrument No.	Service	Sep. Group
*BB-TI-443A	W.R. RCS Hot Leg Temp Loop 4	4
BB-TI-413Y	W.R. RCS Hot Leg Temp Loop 1	NV (5)
*RP-HIS-1	Ctrl Rm Instr Xfr Sw	2
*RP-HIS-2	Ctrl Rm Instr Xfr Sw	4
*RP-HIS-3	Ctrl Rm Instr Xfr Sw	NV (6)

NV - NON-VITAL

* - INSTRUMENTATION AND CONTROLS ON RP118B THAT CAN BE ISOLATED FROM CONTROL ROOM CIRCUITS

7.5 SAFETY-RELATED DISPLAY INSTRUMENTATION

The information necessary to monitor the nuclear steam supply systems, the containment systems, and the balance of plant is displayed on the operator's console and the various control boards located within the control room. These indications include the information to control and operate the unit through all operating conditions, including anticipated operational occurrences and accident and post-accident conditions. Hot shutdown information is also displayed on the auxiliary shutdown control panel located outside the control room (refer to Section 7.4.3). This section is limited to the discussion of those display instruments which provide information to enable the operator to assess reactor status, the onset and severity of accident conditions, and engineered safety feature system (ESFS) status and performance, or to enable the operator to intelligently perform vital manual actions such as safe shutdown and initiation of manual ESFSs. Reactivity control is monitored by sampling of the reactor coolant for boron.

The surveillance instrumentation, which includes indicators, annunciators, recorders, and lights, consists of specific instrumentation for the following functions:

a. Reactor trip

b. Engineered safety features

c. Safe shutdown

This section discusses instrumentation that is required for safety as well as instrumentation that is only indirectly related to safety. The safety-related display instrumentation provided in the control room is listed in Table 7.5-4 and 7.5-5.

This section also furnishes a summary of important display instrumentation provided to monitor system status and performance. The bypassed status indication is treated separately to establish a clear definition of the system of bypass indication. Most of the display instrumentation defined for bypass, status, and performance monitoring in Tables 7.5-1 and 7.5-2 is not safety related (with the exception of the SA066 ESF status cabinets and light display panels, RWST temperature, diesel day tank level, ESW pump discharge pressure and flow, CCW temperature, RHR pump miniflow, containment temperature, AFW flow and turbine speed, RCS temperature, and Gamma-Metrics neutron flux monitors), as shown on Table 7.1-2, Sheet 2, since failure in no way degrades the operation of safety systems and poses no threat to public health and safety.

Refer to Section 1.7 for drawings associated with auxiliary shutdown panel, safety-related display instrumentation, and main control board layouts and ESFS logic diagrams.

7.5.1 REACTOR TRIP SYSTEM

Display instrumentation for the reactor trip system actuation is provided by the nuclear steam system supplier and is discussed in Sections 7.2 and 7.7 and Tables 7.5-1 and 7.5-2.

7.5.2 ENGINEERED SAFETY FEATURE SYSTEM

Display instrumentation is provided to monitor actuation parameters, bypasses, status, and performance of the ESFSs.

7.5.2.1 System Actuation Parameters

7.5.2.1.1 Description

The ESFS actuation parameter display instrumentation comprises those display instrument channels which will provide for informed operator action during and following an accident. The displays provide the information necessary to enable the operator to determine the nature and predict the course of an accident occurrence. They also allow the operator to monitor the effects of an accident through key variables which reflect whether the plant is responding properly to safety measures (and, consequently, whether the ESFS is functioning adequately). The information provided by the displays enables the operator to estimate the magnitude of an impending threat or to determine the potential for radioactive release, to manually initiate the ESFS in the unlikely event of ESFS actuation equipment malfunctions or unanticipated post-accident conditions, and to allow early indication of necessary actions to take to protect the public.

Each parameter monitored for ESFS actuation is displayed in the main control room for operator information. Parameters associated with automatic actuation as well as those required to enable the operator to initiate manual ESFS actuation are displayed. Redundant analog instrument channels, consisting of transmitters, alarm units, and indicators, provide the required information.

Automatic actuation of the ESFS is provided by the engineered safety feature actuation system (ESFAS) described in Section 7.3. The indicators provided for the actuating parameters display the same analog signals monitored by the ESFAS. One indicator is provided for each channel of each parameter.

Table 7.5-1 is a tabulation of the type of readout provided, the number of channels, and the range, accuracy, and location for display instrumentation provided to monitor the ESFS actuation parameters.

The accuracy and ranges are sufficient to monitor the full range of accident conditions. Predicted accident transients will result in less than full-scale readings on safety-related display indicators.

Display instrumentation provided for the ESFS actuation parameters are the same as those used to monitor these parameters during normal operation.

Redundant indicators displaying the same parameter are located close enough to each other to enable visual comparison. Comparisons between duplicate information channels or between functionally related channels will enable the operator to readily identify a malfunction.

The ESFS actuation parameter displays are visually discernible from other displays on the panels so that they are readily located in the event of an accident. Color-coded nameplates identify all safety-related display instrumentation. Wire and cable are color-coded to differentiate between redundant channels and are physically separated within the plant.

7.5.2.1.2 Analysis

DESIGN CRITERIA - The ESFS actuation parameter instruments are designed to remain available in the event of a single failure. Redundant indicator channels are powered from redundant Class 1E 120-V vital instrument ac power supplies (Section 8.3.1.1.5). Display instrumentation is capable of operating independent of offsite power. The indication channels are designed in accordance with Sections 4.2, 4.4, 4.6, and 4.10 of IEEE Standard 279-1971, except that safety-related, Class 1E recorders are required to be operable following, but not necessarily during, an SSE. Recorders for ESFAS channels that monitor safety-related, Regulatory Guide 1.97 Category 1 and 2 parameters at Callaway, as defined in Table 7A-3, do not have to be seismically qualified if Class 1E indicators are provided and the recorders are isolated from the Class 1E portions of the channel. All recorders located on the main control board panels must satisfy seismic II/I requirements. Refer also to Section 7A.3.3. Wiring associated with the ESFS actuation displays is physically separated in accordance with the requirements of Regulatory Guide 1.75 (refer to Appendix 3A). A detailed comparison of the Callaway Plant design to the recommendations of Regulatory Guide 1.97 is contained in Appendix 7A.

Refer to Table 7.1-2 for applicable guides and standards for this equipment.

ADEQUACY - The ESFS actuation parameter displays provide sufficient information to enable the operator to assess accident conditions and to perform the necessary operation of manual ESFS. Each of the ESFAS parameters is displayed, providing the operator with information on those parameters indicative of accident conditions.

The information supplied by the ESFS actuation parameter displays enables the operator to perform manual actuation. Containment sump level indication and refueling water storage tank level indication provide assurance that adequate net positive suction head (NPSH) exists for operation in the sump recirculation mode (Chapter 6.0). Control room ventilation monitors provide the operator with the necessary information on which to base his decision for operation of control room ventilation isolation and filtration.

Containment pressure and air temperature instrumentation provides information for the operator to monitor containment conditions, assess the effectiveness of safety measures in operation, and determine if manual action is necessary. Containment post-accident radiation monitors provide information concerning the radioactive content of the containment atmosphere. Containment hydrogen concentration indication provides information to judge the significance of a metal-water reaction and furnishes the information necessary for manual hydrogen control through the use of the combustible gas control systems.

The recorders provided for the variables furnish trend information, such as the containment pressure and temperature transients, to help predict the course of an accident. In addition, the recorders provide a historical record for post-accident review.

7.5.2.2 System Bypasses

7.5.2.2.1 Description

Bypasses within the ESFAS are indicated on the main control boards or ESFAS cabinets by lights and are alarmed by the plant computer. Bypass of containment airborne gaseous radiation actuation or of containment purge isolation for periodic testing and maintenance and the bypass of low reactor coolant pressure actuation of the safety injection system for startup and shutdown are examples of such bypasses. Bypass is accomplished in the ESFAS cabinets by turning a key associated with a particular actuation bistable. This causes a light to indicate that a bistable within that actuation channel is bypassed. In the latter example, backlighted switches accomplish the bypass function from the main control boards. Refer to Section 7.3 for identification of the bypass functions and their use.

Bypass of ESFAS equipment operation can be effected a number of ways. Handswitch in pull-to-lock position, loss of control power, breaker in test or not in operating position, and closure of manual valves for system or device testing or maintenance are some of the means by which an ESFS or vital supporting system might be rendered inoperative on a system level. The following describes the system of bypass indication and annunciation provided.

The number of bypass features or devices provided for operational purposes or routine testing is minimized by design, but wherever such features or devices are an integral part of the design and are used more frequently than once a year and the bypass results in defeating system functions, a means of indication is provided on the engineered safety feature status panel (ESFSP). Each piece of ESFS equipment (pump, valve, fan, etc., including vital support system equipment) or small group of equipment (subsystem) which must operate upon automatic or manual ESFS actuation is monitored by a status light indicating availability of that component or group of components. Unavailability is indicated by a red indicating light. Thus, a bypass of a component by operation of a control switch or by "racking out" a breaker which results in a bypass of system function

is indicated by a distinctly colored light. A lighted lamp indicates improper status for ESFS operation.

The status lights for actuated ESFS equipment are arranged in groups in a central location on the main control boards, in accordance with the ESFS and the train in that system. In addition to the individual component indication, annunciation is provided on a system-level basis for each ESFS train. A bypass of one or more components within a system train actuates a corresponding audible alarm to annunciate the fact that a train of equipment may be inoperable. Final determination of system inoperability is procedurally controlled.

Automatic system level indication of bypass and inoperable status, called for by Regulatory Guide 1.47, applies only to automatically initiated systems, including those systems which directly support the automatically initiated systems but which themselves may not be automatically initiated because they are normally in the operating mode.

Rendering equipment inoperable through the use of features provided strictly for infrequent evolutions (once a year or less often) is not specifically and automatically indicated. Such features include the P-4/Low T_{avg} bypass-switch, manual valves provided for isolation of equipment for repair, electrical cable connections, or other manual disconnects. However, manual initiation of safety features equipment bypass indication on a system-level basis is provided in the status display panel. Under administrative control, manual bypass indication can be set up or removed. The automatic indication feature cannot be removed by operator action.

7.5.2.2.2 Analysis

DESIGN CRITERIA - The system of bypass indication is designed to satisfy the requirements of IEEE Standard 279-1971 (Paragraph 4.13), Branch Technical Position ICSB 21, and Regulatory Guide 1.47. Refer to Table 7.5-3 for a comparison with Regulatory Guide 1.47 recommendations. The intent of IEEE Standard 308-1971, Surveillance Requirements, is satisfied to the extent of indicating control circuit power availability for ESFS equipment. Other indications responsive to IEEE Standard 308-1971 are described in Chapter 8.0.

The system of indicating lights for bypasses of ESFS actuation channels or sensor channels is located in the ESFAS cabinets and is designed to the requirements of IEEE Standard 279-1971. The indicating lights and associated wiring are located in the cabinets corresponding to the channel indicated and are powered by the power source associated with the cabinet. The ESFAS and associated bypass indication system are designed as seismic Category I equipment, and also are designed to withstand all postulated environmental conditions, as stated in Tables 3.11(B)-1 and 3.11(B)-2.

ADEQUACY - The system of status lights for bypass indication, together with other display information available to the operator, and periodic testing provide assurance that the operator will be constantly aware of the status of the ESFS. The automatic indication

system described previously assures that bypass of control circuits or manual process valves, which could affect system performance, is immediately made obvious.

The bypass indication system is used to supplement administrative procedures by providing indications of safety system availability or status. Administrative procedures will not require operator action based solely on the bypass indicators.

The design of the bypass indication system allows testing during normal plant operation. Both indicating and annunciating functions can be verified.

Process indicators are provided for ESFS actuation parameters (Section 7.5.2.1.1) so that, for parameters that vary in value during plant operation, closure of a manual valve in the transmitter sensing line results in a discrepant indication and response when compared with the corresponding indicators for the redundant channels of the same parameter. The process indicators thus provide indication of impulse line blockage or bypass, which obviates the need for position indication for the manual instrument valves.

For ESFS actuation parameters which do not vary during operation, sufficient redundancy is provided so that more than one manual instrument valve would have to be placed in the wrong position before system level actuation could be blocked.

Diversity in actuating parameters and the capability for manual system actuation make it even more improbable that ESFS function can be blocked by improper instrument valve position. For the preceding reasons, instrument valves are not included in the status light displays.

On items that do not affect the ESFS function no indication system is provided for manual valve position or circuit bypass features.

Operation of manual valves, use of manual disconnects, or other operations occurring once a year or less frequently, which could impair ESFS performance, are controlled by administrative procedures. Thus, the probability for system blocks or bypasses existing undisclosed between periodic functional tests is minimal.

7.5.2.3 System Status

7.5.2.3.1 Description

The information important in evaluating the readiness of the ESFS prior to operation and the status of active components during system operation is displayed for the operator in the main control room. The display information consists of process indicators, indicating lights, alarms, and recorders. The display is sufficient but supplemented by the plant computer outputs.

Table 7.5-1 lists the display information provided, together with the type of readout, number of channels, and their range, accuracy, and location.

Indicators are provided for levels, pressures, and temperatures important to safety feature operation. Each of the indicators is driven by an electronic instrument loop consisting of a transmitter, power supply, and any necessary signal conditioners. Where an alarm is provided, the instrument loop includes an alarm unit providing a contact output to the plant annunciator. Many of the analog signals are monitored by the plant computer to enable display or logging of status or alarm information. Recorders are provided in lieu of, or in addition to, the indicators where a trend or a time history of the process variable is desired.

Indicating lights are provided to monitor equipment status. In addition to the system level availability and bypass indicating lights described in Section 7.5.2.2, indicating lights are provided at each control switch for equipment.

Each motor-driven component (pump, fan, etc.) has ON and OFF indicating lights, each remotely controlled open-closed service valve or damper has corresponding OPEN-CLOSED light indication, and each breaker control switch has its associated open-closed indicating light. A red light is used to indicate an operating status; for example, motor running, valve fully open, or breaker closed. The green light indicates that the equipment is not in an operating state; for example, motor off, valve fully closed, or breaker open. Amber lights, where provided, signify equipment bypassed, locked out, or not in automatic readiness. The indicating lights for a given control circuit are operated from the control circuit power. Thus, loss of control circuit power would be accompanied by a loss of indicating lights for that device.

7.5.2.3.2 Analysis

DESIGN CRITERIA - Status light switches and wiring are designed to the same standards as the associated control circuits. The analog process instruments for status information which are not required for safety system operation do not require special design requirements and are, therefore, of standard commercial quality.

ADEQUACY - Sufficient instrumentation is provided to furnish the plant operator the necessary information and the ESFS status to enable accurate assessment of the readiness of the ESFS prior to operation and the status of active components during operation. The ESFS instrumentation is arranged by system on the main control board to provide the plant operator with a logical arrangement of information to facilitate his evaluation of the ESFS status.

Each power-operated component in the ESFS is equipped with instrumentation to provide equipment status information. Auxiliary contacts from the motor starters or breakers provide motor status indication, while position transmitters and position switches provide valve position indication.

Process variables important for evaluating system readiness are displayed. Pressures and levels providing information on the ESFS status regarding adequate tank inventories

and accumulator pressures are monitored via pressure and level transmitters and indicators.

Resistance temperature detectors and thermocouples are utilized to monitor temperatures of tanks subject to a freezing environment or tanks containing boric acid solutions to preclude undisclosed freezing or crystallization and loss of availability.

7.5.2.4 System Performance

7.5.2.4.1 Description

Display information important in evaluating the performance of an ESFS during periodic test, continuous normal operation, or post-accident operation is provided on the main control boards. Sufficient process indicators, alarms, and recorders are provided to enable the operator to determine whether a system is performing normally or if there is some unanticipated failure within a system. The plant computer monitors selected instrument channels to supplement the display information.

Table 7.5-1 lists the display information provided for the ESFS performance, together with the type of readout, number of channels, and their range, accuracy, and location.

7.5.2.4.2 Analysis

DESIGN CRITERIA - The instrumentation is arranged by system on the main control board to facilitate the operator's evaluation of the system performance. The performance monitoring instrumentation is not required for the operation of the safety systems and does not warrant special design and is, therefore, of standard commercial quality.

ADEQUACY - Sufficient instrumentation is provided to furnish the operator with the information to assess operating ESFS performance.

Sufficient process indicators, alarms, and recorders are provided to enable the operator to determine whether a system is performing normally or if there is some unanticipated failure within a system.

For fluid systems, discharge pressure indication is provided for each pump, and flow indication is provided for each system. Together, the flow and pressure enable the operator to verify proper pump performance and verify fluid delivery performance.

Temperature indication is provided for each system heat exchanger inlet and outlet. The operator has the information, together with the system flow, to verify proper cooling performance.

Temperature indication is also provided for each ventilation system incorporating charcoal filtration, to verify proper temperature range for expected filter performance.

Hydrogen recombiner outlet temperature provides a measure of recombiner performance.

7.5.3 SAFE SHUTDOWN

The important display information provided for operator use during safe shutdown operations is briefly described, analyzed, and tabulated in this section. Further discussion of the functional adequacy and use of the hot and cold shutdown control instrumentation is provided in Section 7.4.

7.5.3.1 Hot Shutdown Control

7.5.3.1.1 Description

The hot shutdown control display instruments are required for manual operations to safely maintain the plant in a hot shutdown condition.

Table 7.5-2 lists the display information provided for hot shutdown control, together with the type of readout, number of channels, and their range, accuracy, and location.

These instruments are provided on the main control board in the main control room and on the auxiliary shutdown control panel outside of the main control room. Two or more separate and redundant channels of display information are provided for each required process variable.

7.5.3.1.2 Analysis

DESIGN CRITERIA - Since the hot shutdown information display systems are designed to protection systems standards, the display parameters remain available in the event of a single failure. Redundant indication channels are powered by redundant, 120-V vital instrument ac power supplies (Section 8.3.1.1.5). The indication channels are designed in accordance with the portions of IEEE Standard 279-1971 applicable to indication channels.

Refer to Table 7.1-2 for applicable guides and standards for this equipment.

ADEQUACY - Compliance with the design criteria ensures the availability of the display instruments to present the information required to maintain the plant in a hot shutdown condition.

Three channels of narrow range level and pressure are indicated on the main control board for each steam generator, which enable the operator to control auxiliary feedwater to the steam generator and to regulate atmospheric relief. Three channels of primary system wide range pressure and pressurizer level are provided which enable the operator to control the pressurizer heaters and coolant inventory.

Similar provisions are made on the auxiliary shutdown control panel where one channel of pressure and narrow range level is displayed for each steam generator and two channels of primary system wide range pressure and pressurizer level are indicated.

7.5.3.2 Cold Shutdown Control

7.5.3.2.1 Description

The display instruments required to bring the plant to a cold shutdown condition are provided in the main control room. For cold shutdown from outside of the control room, see Section 7.4.2.

Table 7.5-2 lists the display information provided for cold shutdown control, together with the type of readout, number of channels, and their range, accuracy, and location.

7.5.3.2.2 Analysis

DESIGN CRITERIA - Refer to Section 7.4.

ADEQUACY - Refer to Section 7.4.

7.5.3.3 System Bypasses

7.5.3.3.1 Description

No bypass indicating light system is provided specifically for the shutdown systems. Certain components used for shutdown have bypass/availability indicating lights provided, if these items also have an ESFS function, but no shutdown system-level bypass indication is provided. Those shutdown components and systems having bypass/availability indicating lights are the auxiliary feedwater system, auxiliary feedwater pump suction valves (essential service water), ECCS centrifugal charging pumps, essential service water pumps, component cooling water pumps, reactor building fan coolers, emergency diesel generators, and the control room ventilation system.

7.5.3.3.2 Analysis

The bypass indications on safe shutdown equipment are included in Table 7.5-2. The analysis provided for the design criteria and adequacy of the ESFS bypass indications in Section 7.5.2.2.2 is applicable to safe shutdown equipment bypasses.

7.5.3.4 System Status

7.5.3.4.1 Description

Information important in evaluating the readiness of the safe shutdown systems prior to operation and the status of components during system operation is displayed in the main

control room. The display information consists of process indicators, indicating lights, alarms, and recorders. In addition to those indicating lights provided in the control room, each control switch on the auxiliary shutdown control panel is provided with associated indicating lights. The plant computer may also be used to supplement the other displays for additional process variables or equipment status.

The description of the equipment provided for ESFS status display information (Section 7.5.2) also applies to the safe shutdown status displays.

7.5.3.4.2 Analysis

The safe shutdown system status displays are listed in Table 7.5-2. The analysis provided for the design criteria and adequacy of the ESFS status displays in Section 7.5.2.3.2 is applicable.

7.5.3.5 System Performance

7.5.3.5.1 Description

The display information important in evaluating the performance of safe shutdown systems during system operation and periodic tests is listed in Table 7.5-2. Indicators, alarms, and recorders are provided to enable the operator to determine whether the system is performing normally or if there is some failure within the system.

7.5.3.5.2 Analysis

The analysis provided for the design criteria and adequacy of the ESFS performance displays is applicable to the safe shutdown systems performance displays.

TABLE 7.5-1 ENGINEERED SAFETY FEATURES - DISPLAYS

LEGENDS

Type of Readout/Display	Readout/Display Location
I - Linear scale indicator or log scale indicator	CB - Control board (main)
R - Recorder ++	SC - System cabinets in control room
L - Indicator light	LP - Local panel
A - Control room annunciator or computer alarm	
C - Display on demand via plant computer	
# - Safety-related, Class 1E	

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Number of Channels Indicated Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Engineered Safety Feature System Actuation						
Reactor coolant system wide range pressure	I #, R	3	1	0-3,000 psig	±4.3*,***	CB, LP, SC
Containment pressure	I #, R	4	1	0-69 psig	±4*,***	CB, SC
Containment pressure (extended range)	I #, R	2	1	-5-180 psig	±4*,***	CB
Steam generator pressure (steam line)	I #, R	3 per loop	1 per loop	0-1,300 psig	±14*,***	CB, LP
Reactor coolant system wide range temperature (hot)	I #, R	2	1	0-700°F	±4*,***	CB, SC
Reactor coolant system wide range temperature (cold)	I #, R	2	1	0-700°F	±4*,***	CB, LP
Refueling water storage tank level	I #, R	4	1	0-100 %	±5*,***	CB, SC
Boric acid tank level	I #, R	2 per tank	1 per tank	0-100 %	±4*,***	CB, SC
Steam generator water level	I #, R	4 per loop (3 narrow, 1 wide range)	1 per loop	0-100 %	±35*,***	CB, SC, LP
Control room air intake - gaseous radioactivity	I #, A, R	2	1	10^{-7} to 10^{-2} µCi/cc	±25	SC

TABLE 7.5-1 (Sheet 2)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Containment gaseous radioactivity	I#, A, R	2	1	10^{-7} to 10^{-2} μCi/cc	±25	SC
Containment hydrogen	I#, R#, A	2	1	0-10 percent	±4	SC, CB
Containment sump level	I#, R#, A	2	1	0 to +13 feet	±4	CB
Containment purge gaseous radioactivity	I#, R, A	2	1	10^{-7} to 10^{-2} μCi/cc	±25	SC
Fuel building gaseous radioactivity	I#, R, A	2	1	10^{-7} to 10^{-2} μCi/cc	±25	SC
Containment air temperature	I#, R#	4	1	0 - 400°F	±4	CB
Containment post accident radiation	I#, R#	2	1	1 - 10^{8} R/hr	+25	CB
Control bldg sump level	I#, A, C	2	1	0 - 66"	±4	CB
Diesel bldg sump level	I#, A, C	2	1	0 - 30"	±4	CB
RHR pump room sump level	I#, A, C	2	1	0 - 24"	±4	CB
Auxiliary bldg sump level	I#, A, C	2	1	0 - 24"	±4	CB
Engineered Safety Feature System Bypasses (Note 1)						
Trip bistable bypass	L, A	1 per train		On for bypass	-	SC, CB
Actuation system signal bypass	L	1 per equip train		On for bypass	-	SC
Equipment bypass	L, A	1 per equipment		On for bypass	-	CB
Equipment Safety Feature Systems Status (Note 1)						
Valve status**	L	1 per valve		Open - closed	-	CB
RWST temperature	I#	2		0 - 200°F	±4	CB
Accumulator tank nitrogen header pressure	A	1 per accumulator		Low alarm	-	CB

TABLE 7.5-1 (Sheet 3)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Equipment status	L	1 per motor		On/off	-	CB
Station 4.l6-kV and 480-Volt load center electrical distribution	L	One/power channel		Current status	-	CB
Diesel day tank level	I#, A	1 per tank		0 - 612 gallons and 0-8.65 ft. (standpipe)	±4	CB, LP
Diesel starting air accumulator pressure	L, A	1 per diesel		Low alarm	-	CB, LP
ESW pumphouse forebay level	C	2		(-243.5)-(-3.5)in.	4	CB
Ultimate heat sink temperature	I, R	1		0 - 150°F	±4	LP
Accumulator pressure	I, A	2 each tank		0 - 700 psig	±1.5	CB
Accumulator water level	I, A	2 each tank		0 - 100 %	±2.25	CB
Containment differential pressure	I	1		(-)85 to (+)85 inches of water	±4	CB
Engineered Safety Feature System Performance						
Containment spray pump discharge pressure	I	1 per pump		0-300 psig	±4	CB
Containment spray flow	I	1 per header		0-2 x 10^6 lb/hr	±4	CB
Essential service water pump discharge pressure	I#	1 per pump		0-300 psig	±4	CB
Essential service water flow	I#	1 per header		0-15 x 10^6 lb/hr	±4	CB
Component cooling water temperature	I#	1 per header		0-200°F	±4	CB
Hydrogen recombiner heater power	I#	1 per unit		0-100 kW	±4	SC
Hydrogen recombiner temperature	I	1 per unit		0-2,000°F	±4	SC
Control room filtration temperature	A, C	1 per filter		150-400°F	±4	CB

TABLE 7.5-1 (Sheet 4)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Fuel building exhaust filter temperature	A, C	1 per filter		150-400°F	±4	CB
Diesel generator performance	-	(see Chapter 8.0)		-	-	-
Residual heat exchanger temperature (inlet/ outlet)	C, R	1 each heat exchanger		50 - 400°F	±1	CB
ECCS charging pump inlet/discharge pressure	I	1 each pump		0 - 150 psig (inlet) 0 - 3,500 psig (disch)	±2	LP
Safety injection pump suction pressure	I	1 each pump		0 - 200 psig	±2	LP
Residual heat removal pump suction pressure	I	1 each pump		0 - 700 psig	±2	LP
Safety injection header pressure	I	1 each header		0 - 2,000 psig	±1	CB
Residual heat removal pump discharge pressure	I, A	1 each pump		0 - 700 psig	±1	CB
Normal charging flow	I, A	1		0 - 200 gpm	±1	CB
Safety injection pump header flow	I	1 each pump		0 - 800 gpm	±1	CB
Residual heat removal pump hot leg recirculation flow	I	1		0 - 4500 gpm	±2	CB
Residual heat removal pump minimum flow	I#	1 each pump		0 - 1,774 gpm	±1.5	LP

++ Safety-related, Class 1E recorders are not required to function during an earthquake, but must function with the required accuracy without operator action as soon as the seismic excitation is removed.

* Channel accuracy in % of span.

** See Section 6.3.5.5 for accumulator isolation valve position indication.

*** Accuracy includes DBE effects.

Note 1: The SA066 ESF status cabinets and light display panels are Class 1E.

TABLE 7.5-2 SAFE SHUTDOWN DISPLAY INFORMATION

LEGENDS

Type of Readout/Display	Readout/Display Location
I - Linear scale indicator or log scale indicator	CB - Control board (main)
R - Recorder	AP - Auxiliary shutdown control panel
L - Indicator light	SC - System cabinets in control room
A - Control room annunciator or computer alarm	
C - Display on demand via the plant computer	
# - Safety-related, Class 1E	

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Hot Shutdown Control						
Steam generator water level (narrow range)	I#, R++	3 per loop	1 per loop	0-100 % (1)	±35*,** (hot)	CB, SC
	I#	1 per loop	1 per loop	0-100 % (1)	±35*,** (hot)	AP
Steam generator water level (wide range)	I#, R	1 per loop	1 per loop	0-100% (2)	±35*,**(hot)	CB, SC
	I#	1 per loop	1 per loop	0-100% (2)	±35*,** (hot)	AP
Steam generator pressure (steam line)	I#, R	3 per loop	1 per loop	0-1,300 psig	±14*,**	CB, SC
	I#	1 per loop	1 per loop	0-1,300 psig	±14*,**	AP
Steam line pressure for SG ARV operation	I#	1 per loop	1 per loop	0-1,500 psig	±4	CB
	I#	1 per loop	1 per loop	0-1,500 psig	±4	AP
Pressurizer water level	I#, R	3	1	0-100 %	±35*,**	CB, SC
	I#	2	1	0-100 %	±35*,**	AP
Reactor coolant system wide range pressure	I#, R	3	1	0-3,000 psig	±4.3*,**	CB, SC
	I#	2	1	0-3,000 psig	±4.3*,**	AP
Auxiliary feedwater pump suction pressure	I#, A	3	1	0-100 psia	±4	CB
	I#	3	1	0-100 psia	±4	AP
Condensate storage tank supply to AFW pressure	I#	3	1	19-36 psia	±4	CB

(1) 438-566 inches above tube sheet
(2) 7-566 inches above tube sheet

TABLE 7.5-2 (Sheet 2)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Cold Shutdown Control						
Those listed above for hot shutdown and the following:						
Source range nuclear instrumentation	I, R	2		1 to 10^6 counts/ second	±7	CB, SC
	I	1		1 to 10^6 counts/ second	±7	AP
Source range neutron flux	I#, R#***	2		0.1 to 10^5 counts/ second	±3	CB
	I#	1		0.1 to 10^5 counts/ second	±3	AP
Intermediate range nuclear instrumentation	I, R	2		8 decades(10^{-11} to 10^{-3} amps)	±7	CB, SC
	I	1		8 decades(10^{-11} to 10^{-3} amps)	±7	AP
Wide range neutron flux	I#, R#***	2		10^{-8} to 200% power	±3	CB
	I#	1		10^{-8} to 200% power	±3	AP
Hot and Cold Shutdown System Bypasses (Note 1)						
See Section 7.5.3.3						
Hot Shutdown System Status (Note 1)						
Condensate storage tank level	I, A	1		0-100 %	±5*,**	CB
	I	1		0-100 %	±5*,**	AP
Condensate storage tank temperature	C	1		30-100°F	±4	CB
Valve status	L	1 per valve assoc with system channel		Open-closed	-	CB, AP
Accumulator tank nitrogen header pressure	A	1 per accumulator		Low alarm	-	CB

TABLE 7.5-2 (Sheet 3)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Equipment status	L	1 per motor assoc with system channel		On-off	-	CB, AP
ECCS centrifugal charging pump room temperature	A	1 per room		High alarm	-	CB
Component cooling water pump room temperature	A	1 per room		High alarm	-	CB
Motor-driven auxiliary feedwater pump room temperature	A	1 per room		High/low alarm	-	CB
Spent fuel pool cooling pump room temperature	A	1 per room		High alarm	-	CB
ESF switchgear room temperature	A	1 per room		High alarm	-	CB
Electrical penetration room temperature	A	1 per room		High alarm	-	CB
Emergency diesel generator room temperature	A, C	1 per room		High alarm	-	CB
Essential service water pump room temperature	A, C	1 per room		High alarm	-	CB
Containment temperature	I#, R#	4		0 - 400°F	±4	CB
Auxiliary shutdown panel room temperature	A	1		High alarm	-	CB
Cold Shutdown System Status (Note 1)						
Those listed above for hot shutdown and the following:						
Residual heat removal pump room temperature	A	1 per room		High alarm	-	CB
Safety injection pump room temperature	A	1 per room		High alarm	-	CB
Hot and Cold Shutdown System Performance						
Auxiliary feedwater pump discharge pressure	I, A, C I	1 per pump 1 per pump		0 - 2,000 psig 0 - 2,000 psig	±4 ±4	CB AP

TABLE 7.5-2 (Sheet 4)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Auxiliary feedwater flow	I#, C	1 per stm gen		0 - 2 x 10^5 lb/hr	±4	CB
	I#	1 per stm gen		0 - 2 x 10^5 lb/hr		AP
Auxiliary feedwater pump turbine speed	I#	1		0 - 6,000 rpm	±4	CB
	I#	1		0 - 6,000 rpm	±4	AP
Reactor coolant temperature (see Note 2)						
Loop 1 cold leg	I#, R	1		0 - 700°F	±4*,**	CB
	I	1 (Note 2)		0 - 700°F	±4*,**	AP
hot leg	I#, R	1		0 - 700°F	±4*,**	CB
	I	1 (Note 2)		0 - 700°F	±4*,**	AP
Loop 2 cold leg	I#, R	1		0 - 700°F	±4*,**	CB
	I#	1 (Note 2)		0 - 700°F	±4*,**	AP
hot leg	I#, R	1		0 - 700°F	±4*,**	CB
Loop 3 cold leg	R	1		0 - 700°F	±4*,**	CB
	I	1 (Note 2)		0 - 700°F	±4*,**	AP
hot leg	R	1		0 - 700°F	±4*,**	CB
Loop 4 cold leg	R	1		0 - 700°F	±4*,**	CB
	I	1 (Note 2)		0 - 700°F	±4*,**	AP
hot leg	R	1		0 - 700°F	±4*,**	CB
	I#	1 (Note 2)		0 - 700°F	±4*,**	AP
Source range nuclear instrumentation	I, R	2		1 to 10^6 counts/sec	±7	CB, SC
	I	1		1 to 10^6 counts/sec	±7	AP
Source range neutron flux	I#, R#***	2		0.1 to 10^5 counts/sec	±3	CB
	I#	1		0.1 to 10^5 counts/sec	±3	AP
Intermediate range nuclear instrumentation	I, R	2		8 decades(10^{-11} to 10^{-3} amps)	±7	CB, SC
	I	1		8 decades(10^{-11} to 10^{-3} amps)	±7	AP

TABLE 7.5-2 (Sheet 5)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Number of Channels Indicated Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations
Wide range neutron flux	I#, R#*** I#	2 1		10^{-8} to 200% power 10^{-8} to 200% power	±3 ±3	CB AP
Hot and Cold Shutdown System Performance						
Reactor vessel water level	I#, R, C	2 static, 2 dynamic	2 static, 2 dynamic	Bottom to top of vessel	(Note 3)	CB, SC
Core exit temperature	R*, L, A, C	50 (minus CETs retired in place)	4 per quadrant	0-2500°F	(Note 4)	SC
Degrees of subcooling	I#, R#,L.A, C	2	NA	200°F subcooled to 2000°F superheated	(Note 5)	CB, SC

* Channel accuracy in % of span.

** Accuracy includes DBE effects.

*** Only the SEN-0061 loop is recorded.

\+ Accuracy is sufficient to indicate that water level is above pressurizer heaters and below 100% of span.

++ One narrow range/level channel per loop is recorded on the main control board steam flow/feed flow recorders, AE-FR-0510, 0520, 0530, and 0540.

Note 1: The SA066 ESF status cabinets and light display panels are Class 1E.

Note 2: Three of the four cold leg indicators on AP are powered from different separation groups, as are the two AP hot leg indicators. The circuitry for the redundant indicators is isolated and runs in different separation groups (two cold leg indicators from separation group 5, one cold leg indicator from separation group 6, one cold leg indicator from Class 1E separation group 4, one hot leg indicator from separation group 5, and one hot leg indicator from Class 1E separation group 4). No single failure can inhibit the indication at the auxiliary shutdown panel of at least one cold leg temperature associated with a steam generator having both an auxiliary feedwater supply and an operable power-operated relief valve, and at least one hot leg temperature associated with a steam generator having both an auxiliary feedwater supply and an operable power-operated relief valve.

Note 3: Static - ±7.73% of narrow range reactor vessel level span (at 100% level, 670°F)**
Dynamic - ±6% of wide range reactor vessel differential pressure span (at all elevations up to 670°F)**

Note 4: Indication of degraded core cooling (incore CETs @ 700°F): ±30°F **
Indication of inadequate core cooling (incore CETs @ 1200°F): ±200°F **

TABLE 7.5-2 (Sheet 6)

Displayed Parameter	Type of Readout/Display	Number of Channels Indicated Available	Number of Channels Indicated Required	Range	Channel Accuracy % of Full Scale	Readout/Display Locations

Note 5: Indication of core subcooling margin
(RCS pressure > 1000 psig): ±50°F **
(400 psig < RCS pressure < 1000 psig): ±100°F **

TABLE 7.5-3 CALLAWAY PLANT DESIGN COMPARISON WITH REGULATORY GUIDE 1.47 DATED MAY 1973, TITLED BYPASSED AND INOPERABLE STATUS INDICATION FOR NUCLEAR POWER PLANT SAFETY SYSTEMS

Regulatory Guide 1.47 Position	Union Electric Position
C. Regulatory Position The following comprises an acceptable method for implementing the requirements of Section 4.13 of IEEE Std 279-1971 and Criterion XIV of Appendix B to 10 CFR Part 50 with respect to indicating the bypass or inoperable status of portions of the protection system, systems actuated or controlled by the protection system, and auxiliary or supporting systems that must be operable for the protection system and the system it actuates to perform their safety-related functions: 1. Administrative procedures should be supplemented by a system that automatically indicates at the system level the bypass or deliberately induced inoperability of the protection system and the systems actuated or controlled by the protection system. 2. The indicating system of C.1. above should also be activated automatically by the bypassing or deliberately induced inoperability of any auxiliary or supporting system that effectively bypasses or renders inoperable the protection system and the systems actuated or controlled by the protection system. 3. Automatic indication in accordance with C.1. and C.2. above should be provided in the control room for each bypass or deliberately induced inoperable status that meets all of the following conditions: a. Renders inoperable any redundant portion of the protection system, systems actuated or controlled by the protection system, and auxiliary or supporting systems that must be operable for the protection system and the systems it actuates to perform their safety-related functions; b. Is expected to occur more frequently than once per year; and c. Is expected to occur when the affected system is normally required to be operable. 4. Manual capability should exist in the control room to activate each system-level indicator provided in accordance with C.1. above.	The Callaway Plant design complies with Regulatory Guide 1.47. Refer to Section 7.5.2.2.1 for a description of the bypassed and inoperable status indication system.

TABLE 7.5-4 SAFETY-RELATED DISPLAY INSTRUMENTATION LOCATED ON THE CONTROL BOARD - (NSSS SCOPE OF SUPPLY)

Parameter	Indicator Tag No.	Notes 1 and 2 PAMS Separation Group I	II
WIDE RANGE RCS T HOT LEG LOOP 1	BB-TI 413A	X	
WIDE RANGE RCS T HOT LEG LOOP 2	BB-TI 423A	X	
WIDE RANGE RCS T COLD LEG LOOP 1	BB-TI 413B		X
WIDE RANGE RCS T COLD LEG LOOP 2	BB-TI 423B		X
PRESSURIZER WATER LEVEL	BB-LI 459A	X	
PRESSURIZER WATER LEVEL	BB-LI 460A		X
PRESSURIZER WATER LEVEL	BB-LI 461	X	
STEAM GEN. LOOP 3 PRESSURE	AB-PI 534A	X	
STEAM GEN. LOOP 1 PRESSURE	AB-PI 514A	X	
STEAM GEN. LOOP 2 PRESSURE	AB-PI 524A	X	
STEAM GEN. LOOP 4 PRESSURE	AB-PI 544A	X	
STEAM GEN. LOOP 1 PRESSURE	AB-PI 515A		X
STEAM GEN. LOOP 2 PRESSURE	AB-PI 525A		X
STEAM GEN. LOOP 4 PRESSURE	AB-PI 545A		X
STEAM GEN. LOOP 3 PRESSURE	AB-PI 535A		X
STEAM GEN. LOOP 1 PRESSURE	AB-PI 516A		X
STEAM GEN. LOOP 4 PRESSURE	AB-PI 546A		X
STEAM GEN. LOOP 2 PRESSURE	AB-PI 526A	X	
STEAM GEN. LOOP 3 PRESSURE	AB-PI 536A	X	
STEAM GEN. LOOP 2 WATER LEVEL N. R.	AE-LI 529	X	
STEAM GEN. LOOP 3 WATER LEVEL N. R.	AE-LI 539	X	
STEAM GEN. LOOP 1 WATER LEVEL N. R.	AE-LI 519		X
STEAM GEN. LOOP 4 WATER LEVEL N. R.	AE-LI 549		X
STEAM GEN. LOOP 1 WATER LEVEL N. R.	AE-LI 518	X	
STEAM GEN. LOOP 2 WATER LEVEL N. R.	AE-LI 528	X	
STEAM GEN. LOOP 3 WATER LEVEL N. R.	AE-LI 538	X	
STEAM GEN. LOOP 4 WATER LEVEL N. R.	AE-LI 548	X	
STEAM GEN. LOOP 1 WATER LEVEL N. R.	AE-LI 517		X
STEAM GEN. LOOP 2 WATER LEVEL N. R.	AE-LI 527		X
STEAM GEN. LOOP 3 WATER LEVEL N. R.	AE-LI 537		X
STEAM GEN. LOOP 4 WATER LEVEL N. R.	AE-LI 547		X
CONTAINMENT PRESSURE N. R.	GN-PI 934		X
CONTAINMENT PRESSURE N. R.	GN-PI 935	X	

TABLE 7.5-4 (Sheet 2)

Parameter	Indicator Tag No.	Notes 1 and 2 PAMS Separation Group I	II
CONTAINMENT PRESSURE N. R.	GN-PI 936		X
CONTAINMENT PRESSURE N. R.	GN-PI 937	X	
STEAM GEN. LOOP 1 W. R. WATER LEVEL	AE-LI 501	X	
STEAM GEN. LOOP 2 W. R. WATER LEVEL	AE-LI 502		X
STEAM GEN. LOOP 3 W. R. WATER LEVEL	AE-LI 503	X	
STEAM GEN. LOOP 4 W. R. WATER LEVEL	AE-LI 504		X
R. C. S. W. R. PRESSURE	BB-PI 405	X	
R. C. S. W. R. PRESSURE	BB-PI 403		X
BORIC ACID TANK WATER LEVEL	BG-LI 102	X	
R. W. S. T. WATER LEVEL	BN-LI 930	X	
R. W. S. T. WATER LEVEL	BN-LI 931		X
R. W. S. T. WATER LEVEL	BN-LI 932	X	
R. W. S. T. WATER LEVEL	BN-LI 933		X
ECCS CENTRIFUGAL CHARGING PUMP FLOW	EM-FI 917A	X	
ECCS CENTRIFUGAL CHARGING PUMP FLOW	EM-FI 917B		X
CONTAINMENT PRESSURE W. R.	GN-PI 938	X	
CONTAINMENT PRESSURE W. R.	GN-PI 939		X
R. C. S. EXCESS LETDOWN HEAT EXCHANGER FLOW TO PRT TEMP	BG-TI 137A	X	
R. C. S. EXCESS LETDOWN HEAT EXCHANGER FLOW TO PRT TEMP	BG-TI 137B		X
R. C. S. EXCESS LETDOWN HEAT EXCHANGER FLOW TO PRT	BG-FI 138A	X	
R. C. S. EXCESS LETDOWN HEAT EXCHANGER FLOW TO PRT	BG-FI 138B		X
BORIC ACID TANK WATER LEVEL	BG-LI 104		X
BORIC ACID TANK WATER LEVEL	BG-LI 105	X	
BORIC ACID TANK WATER LEVEL	BG-LI 106		X
VOLUME CONTROL TANK WATER LEVEL	BG-LI-112	X	
VOLUME CONTROL TANK WATER LEVEL	BG-LI-185		X
RCS W. R. PRESSURE	BB-PI-406		X
SEAL INJECTION FLOW	BG-FI 215A	X	
SEAL INJECTION FLOW	BG-FI 215B		X
REACTOR VESSEL WATER LEVEL N. R.	BB-LI-1311	X	

TABLE 7.5-4 (Sheet 3)

Parameter	Indicator Tag No.	Notes 1 and 2 PAMS Separation Group I	II
REACTOR VESSEL WATER LEVEL W. R.	BB-LI-1312	X	
REACTOR VESSEL WATER LEVEL N. R.	BB-LI-1321		X
REACTOR VESSEL WATER LEVEL W. R.	BB-LI-1322		X
RCS TEMPERATURE MARGIN TO SATURATION	BB-TI-1390A	X	
RCS TEMPERATURE MARGIN TO SATURATION	BB-TI-1390B		X
EXCESS LETDOWN PATH TO PRT ISOLATION	BB-HCI-8157A	X	
EXCESS LETDOWN PATH TO PRT ISOLATION	BB-HCI-8157B		X

NOTES:

1. PAM I routed as Separation Group 1. PAM II routed as Separation Group 4.
2. See Westinghouse process control block diagrams for the applicable protection set.

TABLE 7.5-5 SAFETY-RELATED DISPLAY INSTRUMENTATION
LOCATED ON THE CONTROL BOARD - (BOP SCOPE OF SUPPLY)

Parameter	Indicator Tag No.	Separation Group
SG A STEAM DUMP TO ATMOSPHERE	AB-PIC-01A	01
SG B STEAM DUMP TO ATMOSPHERE	AB-PIC-02A	02
SG C STEAM DUMP TO ATMOSPHERE	AB-PIC-03A	03
SG D STEAM DUMP TO ATMOSPHERE	AB-PIC-04A	04
AUXILIARY FEEDWATER-FLOW TO S.G. D	AL-FI-1A	4
AUXILIARY FEEDWATER-FLOW TO S.G. A	AL-FI-2A	1
AUXILIARY FEEDWATER-FLOW TO S.G. B	AL-FI-3A	2
AUXILIARY FEEDWATER-FLOW TO S.G. C	AL-FI-4A	3
CONDENSATE STORAGE TANK-PRESSURE	AL-PI-37	1
CONDENSATE STORAGE TANK-PRESSURE	AL-PI-38	2
CONDENSATE STORAGE TANK-PRESSURE	AL-PI-39	4
TURBINE DRIVEN AUXILIARY FEED PUMP-SUCTION PRESS.	AL-PI-26A	2
MOTOR DRIVEN AUXILIARY FEED PUMP A-SUCTION PRESS.	AL-PI-25A	1
MOTOR DRIVEN AUXILIARY FEED PUMP B-SUCTION PRESS.	AL-PI-24A	4
CONTROL ROOM AIR INTAKE-GASEOUS RADIOACTIVITY	GK-RIC-4*	4
CONTROL ROOM AIR INTAKE-GASEOUS RADIOACTIVITY	GK-RIC-5*	1
CONTAINMENT-GASEOUS RADIOACTIVITY	GT-RIC-31*	4
CONTAINMENT-GASEOUS RADIOACTIVITY	GT-RIC-32*	1
CONTAINMENT-HYDROGEN	GS-AI-10	4
CONTAINMENT-HYDROGEN	GS-AI-19	1
CONTAINMENT SUMP NORMAL LEVEL	LF-LI-10	4
CONTAINMENT SUMP NORMAL LEVEL	LF-LI-9	1
CONTAINMENT PURGE-GASEOUS RADIOACTIVITY	GT-RIC-33*	4
CONTAINMENT PURGE-GASEOUS RADIOACTIVITY	GT-RIC-22*	1
FUEL BUILDING-GASEOUS RADIOACTIVITY	GG-RIC-28*	4
FUEL BUILDING-GASEOUS RADIOACTIVITY	GG-RIC-27*	1
CONTAINMENT-AIR TEMPERATURE	GN-TI-61	4
CONTAINMENT-AIR TEMPERATURE	GN-TI-60	1

TABLE 7.5-5 (Sheet 2)

Parameter	Indicator Tag No.	Separation Group
CONTAINMENT-AIR TEMPERATURE	GN-TI-63	4
CONTAINMENT-AIR TEMPERATURE	GN-TI-62	1
CONTROL BUILDING SUMP-LEVEL	LF-LI-125	4
CONTROL BUILDING SUMP-LEVEL	LF-LI-124	1
DIESEL GENERATOR BUILDING SUMP-LEVEL	LE-LI-106	4
DIESEL GENERATOR BUILDING SUMP-LEVEL	LE-LI-105	1
RHR PUMP ROOM SUMP-LEVEL	LF-LI-101	4
RHR PUMP ROOM SUMP-LEVEL	LF-LI-102	1
AUXILIARY BUILDING SUMP-LEVEL	LF-LI-104	4
AUXILIARY BUILDING SUMP-LEVEL	LF-LI-103	1
NK21 BAT CHARGER AMPS	NK-II-1	1
NK11 BAT AMPS	NK-II-2	1
NK01 125 V DC BUS VOLTS	NK-EI-1	1
NK22 BAT CHARGER AMPS	NK-II-3	2
NK12 BAT AMPS	NK-II-4	2
NK02 125 V DC BUS VOLTS	NK-EI-2	2
NK23 BAT CHARGER AMPS	NK-II-5	3
NK13 BAT AMPS	NK-II-6	3
NK03 125 V DC BUS VOLTS	NK-EI-3	3
NK24 BAT CHARGER AMPS	NK-II-7	4
NK14 BAT AMPS	NK-II-8	4
NK04 125 V DC BUS VOLTS	NK-EI-4	4
NK21 BAT CHARGER AMMETER POTENTIOMETER	NK-IY-1	1
NK22 BAT CHARGER AMMETER POTENTIOMETER	NK-IY-3	2
NK23 BAT CHARGER AMMETER POTENTIOMETER	NK-IY-5	3
NK24 BAT CHARGER AMMETER POTENTIOMETER	NK-IY-7	4
NK11 BAT AMMETER POTENTIOMETER	NK-IY-2B	1
NK12 BAT AMMETER POTENTIOMETER	NK-IY-4B	2
NK13 BAT AMMETER POTENTIOMETER	NK-IY-6B	3
NK14 BAT AMMETER POTENTIOMETER	NK-IY-8B	4

TABLE 7.5-5 (Sheet 3)

Parameter	Indicator Tag No.	Separation Group
RWST TEMP	BN-TI-2	1
RWST TEMP	BN-TI-5	4
CTMT RECIRC SUMP B LEVEL	EJ-LI-8	4
CTMT RECIRC SUMP A LEVEL	EJ-LI-7	1
CCW SURGE TANK B LEVEL	EG-LI-2	4
CCW HX B DISCH TEMP	EG-TI-32	4
ESW B PMP DISCH FLOW	EF-FI-54	4
ESW B PMP DISCH PRESS.	EF-PI-2	4
ESW TRAIN B TEMP	EF-TI-62	4
ESW TRAIN A TEMP	EF-TI-61	1
ESW A PMP DISCH PRESS.	EF-PI-1	1
ESW A PMP DISCH FLOW	EF-FI-53	1
CCW HX A DISCH TEMP	EG-TI-31	1
CCW SURGE TK A LEVEL	EG-LI-1	1
CCW HX TO RCP FLOW	EG-FI-128	1
CCW HX TO RCP FLOW	EG-FI-129	4
EMERGENCY FUEL OIL DAY TK A LVL	JE-LI-12A	1
EMERGENCY FUEL OIL DAY TK B LVL	JE-LI-32A	4
4.16 KV BUS NB01 VOLTS	NB-EI-1	1
4.16 KV BUS NB02 VOLTS	NB-EI-2	4
4.16 KV BUS NB01 SYNCHROSCOPE	NB-EI-3	1
4.16 KV BUS NB02 SYNCHROSCOPE	NB-EI-4	4
AFP TURBINE SPEED CONTROL	FC-HIK-313A	2
CTMT HIGH RANGE RADIATION	GT-RIC-59	1
CTMT HIGH RANGE RADIATION	GT-RIC-60	4
SOURCE RANGE NEUTRON FLUX	SE-NI-60A	1
WIDE RANGE NEUTRON FLUX	SE-NI-60B	1
SOURCE & WIDE RANGE NEUTRON FLUX (1)	SE-NIR-61	4

* Digital display on radiation monitoring panel SP-067.

NOTES:

1. Instrument on the MCB is a dual pen indicating recorder.

7.6 ALL OTHER INSTRUMENTATION SYSTEMS REQUIRED FOR SAFETY

7.6.1 INSTRUMENTATION AND CONTROL POWER SUPPLY SYSTEM

The instrumentation and control power supply system is described in Section 8.3.1.1.5.

Safety-related BOP transmitters not powered directly from the system described in 8.3.1.1.5 are powered by input buffers in the BOP analog equipment cabinets.

Each BOP electronic analog input buffer is able to withstand an open circuit, a short circuit, or a single or multiple-point ground on the field wiring, without affecting any other instrument loop in any separation group.

An open circuit would interrupt the field current and drive the buffer output offscale "low." The field bus power supply voltage is not high enough to cause any damage if it were suddenly unloaded. There would be no consequential damage to the electronics.

A short circuit would apply the full field bus voltage across on-board current-limiting resistors designed and provided to limit such current to a safe value. The buffer output would be driven to the high limit with no consequential damage to the electronics.

A single ground on an input buffer field line would connect one side of the field bus power supply to system ground through an on-board, current-limiting resistor designed and provided to limit the resultant current to a safe value. The buffer output would take on some arbitrary value, with no consequential damage to the electronics.

A ground on both field lines of an input buffer would result in a condition similar to an input line short circuit. The buffer output would be driven to the high limit, but there would be no consequential damage to the electronics.

7.6.2 RESIDUAL HEAT REMOVAL SYSTEM ISOLATION VALVES

7.6.2.1 Description

The residual heat removal system (RHRS) isolation valves are normally closed and are opened only for residual heat removal system operation after system pressure is reduced to approximately 400 psig and system temperature has been reduced to approximately 350°F.

There are two motor-operated valves in series in each of the two residual heat removal pump suction lines from the reactor coolant system (RCS) hot legs. The two valves nearest the RCS (valves 8702A and 8702B) are designated as the inner isolation valves, while the two valves nearest the residual heat removal pumps (valves 8701A and 8701B) are designated as the outer isolation valves. The interlock and alarm features provided for the outer isolation valves, shown on Figure 7.6-1 (Sheet 1), are identical to those provided for the inner isolation valves, shown on Figure 7.6-1 (Sheet 2), except that

equipment diversity is employed by virtue of the fact that PT 405 is of a different manufacture than PT 403.

Each valve is interlocked so that it cannot be opened unless the RCS pressure is below a preset pressure. This interlock prevents the valve from being opened when the RCS pressure plus the residual heat removal pump pressure is above the RHRS design pressure. A control room alarm will actuate if an RHR suction isolation valve is not fully closed and RCS pressure is greater than the design pressures for RHR system operation. Power is removed from these valves above the interlock setpoint to prevent inadvertant opening during operation.

In addition, the valves cannot be opened unless the isolation valves in the following lines are closed:

a. Recirculation line from the residual heat exchanger outlet to the suction of the high head safety injection pumps.

b. RHR pump suction line from the refueling water storage tank.

c. RHR pump suction line from the containment sump.

7.6.2.2 Analysis

Based on the scope definitions in IEEE Standards 279-1971 and 338-1971, these criteria do not apply to the residual heat removal isolation valve interlocks. However, because of the possible severity of the consequences of loss of function, the requirements of IEEE Standard 279-1971 have been applied with the following comments.

a. For the purpose of applying IEEE Standard 279-1971 to this circuit, the following definitions are used:

   (1) Protection system

   The two valves in series in each line and all components of their interlocking and closure circuits.

   (2) Protective action

   The interlocks which prevent opening an RHRS isolation valve when RCS pressures are above the preset value.

b. IEEE Standard 279-1971, Section 4.10

   The above-mentioned pressure interlock and alarm signals and logic will be tested on-line from the analog signal through to the train signal which activates the slave relay (the slave relay provides the final output signal to

the valve control circuit). Actuation to permit opening the valve is not performed because this could leave only one remaining valve to isolate the low pressure RHRS from the RCS, which would reduce the safety margin.

c. IEEE Standard 279-1971, Section 4.15

This requirement does not apply, as the setpoints are independent of the mode of operation and are not changed.

Environmental qualification of the valves and wiring is discussed in Section 3.11(N).

7.6.3 REFUELING INTERLOCKS

Electrical interlocks (i.e., limit switches), as discussed in Section 9.1.4, are provided for minimizing the possibility of damage to the fuel during fuel handling operations.

7.6.4 ACCUMULATOR MOTOR-OPERATED VALVES

The safety injection system accumulator discharge isolation valves are motor-operated, normally open valves which are controlled from the main control board.

These valves are interlocked so that:

a. They open automatically on receipt of an SIS with the main control board switch in either the "AUTO" or "CLOSE" position.

b. They open automatically whenever the RCS pressure is above the safety injection unblock pressure (P-11) specified in the Callaway Technical Specifications only when the main control board switch is in the "AUTO" position.

c. They cannot be closed as long as an SIS is present.

The interconnection of the interlock signals to the accumulator isolation valve meets the following criteria:

a. Automatic opening of the accumulator isolation valves when: (1) the primary coolant system pressure exceeds a preselected value (specified in the Callaway Technical Specifications) or (2) a safety injection signal has been initiated. Both signals are provided to the valves.

b. Utilization of a safety injection signal to automatically remove (override) any bypass features that are provided to allow an isolation valve to be closed for short periods of time when the RCS is at pressure (in accordance with the provisions of the Callaway Technical Specifications).

As a result of the confirmatory SIS, isolation of an accumulator with the reactor at pressure is acceptable.

c. Removal of power from the valve operators is discussed in Section 6.3.2.

The control circuit for these valves is shown on Figure 7.6-2. The valves and control circuits are further discussed in Sections 6.3.2 and 6.3.5.

The four main control board position switches for these valves provide a "spring return to auto" from the open position and a "maintain position" from the closed position.

The "maintain closed" position is required to provide an administratively controlled manual block of the automatic opening of the valve at pressure above the safety injection unblock pressure (P-11). The manual block or "maintain closed" position is required when performing periodic check valve leakage tests when the reactor is at pressures above P-11. The maximum permissible time that an accumulator isolation valve can be closed when the reactor is at pressure (above 1000 psig) is specified in the Callaway Technical Specifications.

Administrative control is required to ensure that any accumulator isolation valve which has been closed at pressures above the safety injection unblock pressure is reopened, that the circuit breaker is subsequently locked in the open position, and that the main control board position switch is returned to the "AUTO" position. Valve position alarms will sound if the valves are not open when above P-11.

During plant shutdown, the accumulator isolation valves are closed. To prevent an inadvertent opening of these valves during that period, the valve motor circuit breakers will be locked in the open position. These valve circuit breakers are closed momentarily during the startup procedures in order to open the valves, after which the breakers are again locked in the open position.

These normally open, motor-operated valves have alarms, indicating a malpositioning (with regard to their emergency core cooling system function during the injection phase). The alarms sound in the main control room.

An alarm will sound for any accumulator isolation valve, under the following conditions, when the RCS pressure is above the "safety injection unblocking pressure."

a. Valve motor-operated limit switch indicates valve not open.

b. Valve stem-operated limit switch indicates valve not open. The alarm on this switch will repeat itself at given intervals.

Additionally, an ESF status panel bypass indication is provided whenever any of these valves leaves the fully open position.

7.6.5 SWITCHOVER FROM INJECTION TO RECIRCULATION

The details of achieving cold leg recirculation following safety injection are given in Section 6.3.2.8 and on Table 6.3-8. Figure 7.6-3 shows the logic which will be used to automatically open the sump valves.

7.6.6 INTERLOCKS FOR RCS PRESSURE CONTROL DURING LOW TEMPERATURE OPERATION

The basic function of the RCS pressure control during low temperature operation is discussed in Section 5.2.2. As noted in Section 5.2.2, this pressure control includes automatic actuation logic for two pressurizer power-operated relief valves (PORVs). The function of this actuation logic is to continuously monitor RCS temperature and pressure conditions, with the actuation logic unblocked only when plant operation is at a temperature below the reference nil ductility temperature (RNDT). The monitored system temperature signals are processed to generate the reference pressure limit program which is compared to the actual monitored RCS pressure. This comparison provides an actuation signal to an actuation device which will cause the PORV to automatically open, if necessary, to prevent pressure conditions from exceeding allowable limits. Refer to Figure 7.6-4 for the block diagram showing the interlocks for RCS pressure control during low temperature operation.

The generating station pressure and temperature variables required for this interlock are channelized as follows:

a. Pressure and Temperature Inputs to PCV455A

   (1) Four wide range RCS temperature signals derived from channels in a Train A related protection set.

   (2) One wide range RCS pressure signal derived from a channel in a Train A related protection set.

b. Pressure and Temperature Inputs to PCV456A

   (1) Four wide range RCS temperature signals derived from channels in a Train B related protection set.

   (2) One wide range RCS pressure signal derived from a channel in a Train B related protection set.

The wide range RCS temperatures in each protection set are auctioneered in an auctioneering device in each protection set to select the lowest reading.

An alarm is actuated when the auctioneered low temperature from the RCS wide range temperature channels falls within the range of cold overpressure mitigation system

(COMS) applicability, thereby alerting the operator to arm the RCS cold overpressure mitigation system, which automatically opens the block valve.

The lowest reading is selected and input to a function generator which calculates the reference pressure limit program, considering the plant's allowable pressure and temperature limits. Also available from the related protection set is the wide range RCS pressure signal. The reference pressure from the function generator is compared to the actual RCS pressure monitored by the wide range pressure channel. The error signal derived from the difference between the reference pressure and the actual measured pressure will first annunciate a main control board alarm whenever the actual measured pressure approaches, within a predetermined amount, the reference pressure. On a further increase in measured pressure, the error signal will generate an actuation signal.

The monitored generating station variables that generate the actuation signal for the redundant PORV are processed in a similar manner.

Upon receipt of the actuation signal, the actuation device will automatically cause the PORV to open. Upon sufficient RCS inventory letdown, the operating RCS pressure will decrease, clearing the actuation signal. Removal of this signal causes the PORV to close.

7.6.6.1 Analysis of Interlocks

Many criteria presented in IEEE Standards 279-1971 and 338-1971 do not apply to the interlocks for RCS pressure control during low temperature operation, because the interlocks do not perform a protective function but, rather, provide automatic pressure control at low temperatures as a back-up to the operator. However, although IEEE Standard 279-1971 criteria do not apply, some advantages of the dependability and benefits of an IEEE Standard 279-1971 design have accrued by including selected elements, as noted above, in the protection sets and by organizing the control of the two PORVs (either of which can accomplish the RCS pressure control function) into dual channels.

The design of the low temperature interlocks for RCS pressure control is such that pertinent features include:

a. No credible failure at the output of the protection set racks, after the output leaves the racks to interface with the interlocks, will prevent the associated protection system channel from performing its protective function because of the separation of Train B interlocks from Train A (see Figure 7.6-4).

b. Testing capability for elements of the interlocks within (not external to) the protection system is consistent with the testing principles and methods discussed in Section 7.2.2.2.3, item J. It should be noted that there is an annunciator which provides an alarm when the COMS is armed coincident with a closed position of the motor-operated (MOV) pressurizer relief block

valve. This MOV is in the same fluid path as the PORV, with a separate MOV and alarm used with the second PORV.

c. A loss of offsite power will not defeat the provisions for an electrical power source for the interlocks because these provisions are through onsite power, which is described in Section 8.3.

7.6.7 ISOLATION OF ESSENTIAL SERVICE WATER (ESW) TO THE AIR COMPRESSORS

7.6.7.1 Description

As stated in Section 9.2.1.2.2.1, ESW flow to the nonsafety-related air compressors and associated aftercoolers is maintained following a DBA. Instrumentation and controls are provided to automatically isolate each train of the ESW to the air compressors on high flow. ESW to the air compressors can also be isolated by remote manual means.

Each control system (one per train of the ESW) utilizes a differential pressure transmitter and bistable which senses flow through the associated isolation valve. On high flow (indicative of gross leakage in the nonseismic portion of the system), the control system automatically closes the isolation valve.

The isolation valve will remain in the closed position until the valve is manually reset by the operator in the control room.

A means of remote manual isolation is provided in the control room. The status of each isolation valve is indicated by open and closed indicating lights in the control room.

The isolation valves are air operated and are designed to fail closed on the loss of air and electrical power.

a. Initiating circuits

Each isolation valve is automatically actuated by flow monitoring instrumentation. The isolation valves can also be closed via control switches in the control room.

b. Logic

The logic diagram for the isolation of the ESW to the air compressors is provided in Section 1.7.

c. Bypass

No bypass is provided.

d. Interlock

No interlock is provided.

e. Redundancy

Redundancy is accomplished on a system basis. Each train of the ESW is provided with an independent control system and isolation valve.

f. Actuated devices

The isolation valves are the actuated devices.

g. Supporting systems

The controls for ESW isolation to the air compressors are powered from the Class 1E power system (refer to Chapter 8.0).

h. Portion of system not required for safety

Isolation valve position inputs to the station computer are not required for safety.

i. Design bases

The design bases for ESW isolation to the air compressors are described in Section 9.2.1.2.1 (Safety Design Bases 5 and 6).

Additionally, Section 7.3.1.1.2a. and b. are applicable to the control system components.

7.6.7.2 Analysis

a. Conformance to NRC regulatory guides

(1) Regulatory Guide 1.22

The isolation system controls can be tested periodically.

(2) Regulatory Guide 1.29

The isolation system controls are designed to withstand the effects of an earthquake without loss of function. The isolation system controls are classified seismic Category I, in accordance with the guide.

b. Conformance to IEEE Standard 279-1971

The controls for the isolation system conform to the applicable requirements of IEEE Standard 279-1971. The control circuits are designed so that any single failure will not compromise the ESW system's safety function. This is accomplished by redundancy provided in the ESW system. Each isolation system utilizes control power from independent Class 1E power systems. In order to prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between control channels.

c. Conformance to other criteria and standards

Conformance to other criteria and standards is indicated in Table 7.1-2.

7.6.8 ISOLATION OF THE NONSAFETY-RELATED PORTION OF THE COMPONENT COOLING WATER (CCW) SYSTEM

7.6.8.1 Description

The nonseismic portion of the CCW system is isolated by two isolation valves in series that are provided in both the supply and return lines (see Figure 9.2-3). These valves automatically close upon low-low surge tank level or SIS. The nonseismic portion of the CCW system can also be isolated by remote manual means.

Two independent level transmitters (one per surge tank) are provided. On low-low surge tank level, the isolation valves are automatically closed and will remain in the closed position until the valves are manually reset by the operator in the control room. Each level transmitter and its associated bistable provides isolation signals to one valve in the supply line and one valve in the return line.

The isolation valves are air operated and are designed to fail closed on loss of air and electrical power.

A means of remote manual isolation is provided in the control room. The status of each isolation valve is indicated by open and closed indicating lights in the control room.

The SIS to the isolation valves is discussed in Section 7.3.

a. Initiating circuits

Each isolation valve is automatically actuated by level monitoring instrumentation. The isolation valves can also be closed via control switches in the control room.

b. Logic

The logic diagram for the isolation of the nonseismic portion of the CCW system is provided in Section 1.7.

c. Bypass

No bypass is provided.

d. Interlock

An interlock is provided to defeat the isolation of one set of isolation valves (one in the supply line and one in the return line) on low-low surge tank level. This interlock will allow continued plant operation for a period of time if the corresponding train of the CCW is out of service.

e. Redundancy

Redundancy is accomplished by providing two independent sets of level instrumentation.

f. Diversity

Diversity within the types of instrumentation functions that can initiate isolation of EGHV0069A/B and EGHV0070A/B is accomplished by actuation circuitry associated with a safety injection signal (SIS) or low-low surge tank level. The CCW system is required to mitigate Chapter 6 and Chapter 15 accidents and transients that generate a SIS or rely on RHR for safe shutdown. Diversity for the generation of the SIS is accomplished by actuation on low pressurizer pressure, low steamline pressure, or containment pressure High-1. The CCW system must also be capable of isolating the non-safety, non-seismic piping to the radwaste service loads after a postulated hazard (earthquake, pipe break, etc.) as discussed in Chapter 3. For such an event, isolation on low-low surge tank level or by remote manual operator action to close EGHV0069A/B and EGHV0070A/B from the main control room is available.

g. Actuated devices

The isolation valves are the actuated devices.

h. Supporting systems

The controls for isolation of the nonseismic portion of the CCW system are powered from two independent Class 1E power systems.

i. Portion of system not required for safety

Isolation valve position inputs to the station computer are not required for safety.

j. Design bases

The design bases for isolation of the nonsafety-related portion of the CCW system are described in Section 9.2.2.1.1 (Safety Design Bases 5 and 6).

Additionally, Section 7.3.1.1.2a and b are applicable to the control system components.

7.6.8.2 Analysis

a. Conformance to NRC regulatory guides

(1) Regulatory Guide 1.22

The isolation system controls can be tested periodically.

(2) Regulatory Guide 1.29

The isolation system controls are designed to withstand the effects of an earthquake without loss of function. The isolation system controls are classified seismic Category I, in accordance with the guide.

b. Conformance to IEEE Standard 279-1971

The controls for the isolation system conform to the applicable requirements of IEEE Standard 279-1971. The control circuits are designed so that any single failure will not compromise the CCW system's safety function. This is accomplished by redundant flow and surge tank level instrumentation.

The CCW isolation system and the surge tank level instrumentation utilize power from two independent Class 1E power systems. In order to prevent interaction between the redundant systems, the control channels are wired independently and separated with no electrical connections between control channels.

c. Conformance to other criteria and standards

Conformance to other criteria and standards is indicated in Table 7.1-2.

7.6.9 FIRE PROTECTION AND DETECTION

Fire protection and detection is discussed in Section 9.5.1.

7.6.10 INTERLOCKS FOR PRESSURIZER PRESSURE RELIEF SYSTEM

7.6.10.1 Description of Pressurizer Pressure Relief System

The pressurizer pressure relief (PPR) system provides the following:

a. Capability for RCS overpressure mitigation during cold shutdown, heatup, and cooldown operations to minimize the potential for impairing reactor vessel integrity when operating at or near the vessel ductility limits.

b. Capability for RCS depressurization following Condition II, III, and IV events (e.g., see Sections 15.5.1 and 15.6.3).

7.6.10.2 Description of Pressurizer Pressure Relief System Interlocks

Interlocks for the PPR system control the opening and closing of the pressurizer PORVs. These interlocks provide the following functions:

a. Pressurizer pressure control via Class 1E automatic actuation circuit (refer to Section 7.7.1.5 for a description).

b. RCS pressure control during low temperature operation (refer to Sections 5.2.2 and 7.6.6 for a description).

c. RCS pressure control to achieve and maintain a cold shutdown and to heatup, using equipment that is required for safety (refer to Appendix 5.4A for a description).

The interlock functions that provide pressurizer pressure control are derived from process parameters as shown on Figure 7.2-1, Sheet 11 and the interlock logic functions as well as process parameter inputs required for low temperature operation, as shown on Figure 7.6-4. The functions shown on Figure 7.6-4 include those needed for the PORV block valves as well as the pressurizer PORVs to meet both interlock logic and manual and automatic operation requirements where manual operation is at the main control board.

7.6.11 SWITCHOVER ECCS OF CHARGING PUMP SUCTION TO RWST ON LOW-LOW VCT LEVEL

7.6.11.1 Description

The suction of the ECCS charging pumps is normally supplied by a line containing two normally open motor-operated valves which connects to the bottom of the volume control tank (VCT). These VCT outlet isolation valves are designated as LCV-112B, which is assigned to the A train, and LCV-112C, which is assigned to the B train.

Each VCT outlet isolation valve is controlled by its train associated level channel. Refer to Figure 7.6-5 (Sheet 1 of 2) for the logic diagram. When the control switch is in the normal position, the valve receives a signal to close on a low-low level signal from its associated channel. The valves also receive a signal to close on an SIS signal.

The interlock between the above signal and the emergency makeup signal from its train associated RWST valve position prevents the valve from automatically closing unless its train associated valve from the RWST to the charging pump suction header is open. This system ensures that the ECCS charging pumps will always have a source of fluid and protects them against loss of NPSH and cavitation damage.

Each RWST valve is controlled by its train associated level channel. Refer to Figure 7.6-5 (Sheet 2 of 2) for the logic diagram. When the control switch is in the normal position, the valve receives a signal to open on a low-low level signal from its associated channel. The valves also receive a signal to open on an SIS signal.

In order to avoid any interface between control grade instrumentation functions and protection grade instrumentation channels which are derived from level transmitters LT-112 and LT-185, a third VCT level instrumentation channel derived from level transmitter LT-149 is provided. This channel performs all the control grade functions so that LT-112 and LT-185 may be dedicated to switchover of ECCS charging pump suction to the RWST on low-low VCT level.

7.6.11.2 Evaluation of Switchover of ECCS Charging Pump Suction

In addition to having complete electrical separation from channels LT-112 and LT-185, the upper level tap from LT-149 is on the VCT vent line at the same pressure point as pressure transmitter PT-115. This ensures adequate physical separation of the different grades of equipment. LT-185 and LT-149 share the lower level tap. A postulated rupture of this tap would result in a false "empty" indication by the affected transmitter, which would initiate switchover.

7.6.12 INSTRUMENTATION FOR MITIGATING CONSEQUENCES OF INADVERTENT BORON DILUTION

7.6.12.1 Description

Instrumentation is provided to mitigate the consequences of inadvertent addition of unborated, primary grade water into the reactor coolant system. The boron dilution mitigation system is identical to that reviewed and approved by the NRC for initial licensing of Comanche Peak Units 1 and 2 (Docket Nos. 50-445 and 50-446).

Figure 7.6-6 is a simplified system block diagram showing the flux doubling detection system and the protection system output for isolation valve actuation.

In the event of a boron dilution transient, the nuclear instrumentation source range in conjunction with the flux-multiplication meter will detect a multiplication of the neutron flux. This information is sent to the solid state protection system which automatically initiates isolation valve movement to terminate the transient. An alarm is sounded at the time for plant operators to indicate that flux multiplication in excess of the setpoint has occurred and isolation valve movement started.

Credit is taken for the instrumentation to provide for operator alert and for automatically initiating isolation valve movement in Modes 3, 4, and 5.

7.6.12.2 Analysis

The analysis of effects and consequences of inadvertent boron dilution transients is covered in Section 15.4.6.

7.6.12.3 Qualification

Qualification of the instrumentation is discussed in WCAP-8587 Supplement 1, "Equipment Qualification Data Package" ESE-47.

7.6.13 ECCS CHARGING PUMP MINIFLOW INTERLOCK

7.6.13.1 Description

The ECCS charging pump miniflow interlock provides the following semi-automatic miniflow valve opening and closing features. The interlock automatically closes the miniflow valve with the manual main control board switch for the valve in the normal position when the actual flow from the pump increases above the preset amount coincident with the presence of a latched-in safety injection actuation signal. The interlock also automatically opens the miniflow valve with the manual main control board switch for the valve in the normal position when the actual flow from the pump decreases below the preset amount coincident with the presence of a latched-in safety injection

actuation signal. There is an interlock for the Train A pump miniflow valve and a redundant interlock for the Train B pump miniflow valve.

Included in this interlock logic is a retentive memory to retain the SIS until the reset for this valve is actuated. The purpose of this retention is to maintain miniflow isolation control after the primary SIS has been reset at the systems level at the main control board.

7.6.14 NEUTRON FLUX MONITORING SYSTEM

7.6.14.1 Description

Redundant Class 1E neutron flux monitors, independent from the NSSS protection system, have been provided in the Callaway Plant design. The monitors have the capability to monitor excore neutron flux from 10^{-8} to 200 percent power. Class 1E indication is provided on the main control panel and auxiliary shutdown panel. In addition, a Class 1E recorder is provided on the main control panel to track the neutron flux during normal operation and during an event.

7.6.14.2 Qualification

Qualification of instrumentation is discussed in the SNUPPS Report of Independent Review of Environmental Qualification Programs to NUREG-0588.

7.7 CONTROL SYSTEMS NOT REQUIRED FOR SAFETY

The general design objectives of the plant control systems are:

a. To establish and maintain power equilibrium between the primary and secondary system during steady state unit operation.

b. To constrain operational transients so as to preclude unit trip and reestablish steady state unit operation.

c. To provide the reactor operator with monitoring instrumentation that indicates all required input and output control parameters of the systems and provides the operator with the capability of assuming manual control of the system.

7.7.1 DESCRIPTION

The plant control systems described in this section perform the following functions:

Reactor Control System

a. Enables the nuclear plant to accept a step load decrease of 10 percent and a ramp decrease of 5 percent per minute over the entire power range without reactor trip, steam dump, or pressurizer relief actuation, subject to possible xenon limitations.

b. Maintains reactor coolant average temperature (T_{avg}) within prescribed limits by creating the bank demand signals for manually moving groups of RCCAs during normal operation and operational transients. The T_{avg} control also supplies a signal to pressurizer water level control and steam dump control.

Rod Control System

a. Provides for reactor power modulation by manual or automatic (insertion only) control of control rod banks in a preselected sequence and for manual operation of individual banks.

b. Systems for monitoring and indicating

   1. Provide alarms to alert the operator if the required core reactivity shutdown margin is not available due to excessive control rod insertion.

   2. Display control rod position.

3. Provide alarms to alert the operator in the event of control rod deviation exceeding a preset limit.

Plant Control System Interlocks

a. Prevent further manual withdrawal of the control banks when signal limits are approached that indicate the approach to a DNBR limit or kW/ft limit.

b. Limit automatic turbine load increase to values for which the NSSS has been designed.

Pressurizer Pressure Control

Maintains or restores the pressurizer pressure to the design pressure ±35 psi (which is within reactor trip and relief and safety valve actuation setpoint limits) following normal operational transients that induce pressure changes by control (manual or automatic) of heaters and spray in the pressurizer. Provides steam relief by controlling the power relief valves.

Pressurizer Water Level Control

Establishes and maintains the pressurizer water level within specified limits as a function of the average coolant temperature. Changes in level are caused by coolant density changes induced by loading, operational, and unloading transients. Level changes are produced by means of charging flow control (manual or automatic) as well as by manual selection of letdown throttle valves. Maintaining coolant level in the pressurizer within prescribed limits by actuating the charging and letdown system provides control of the reactor coolant water inventory.

Steam Generator Water Level Control

a. Establishes and maintains the steam generator water level within predetermined limits during normal operating transients.

b. The steam generator water level control system also maintains the steam generator water level to within predetermined limits and unit trip conditions. It regulates the feedwater flow rate so that under operational transients the water level for the reactor coolant system does not decrease below a minimum value. Steam generator water inventory control is manual or automatic through the use of feedwater control valves.

Steam Dump Control (Also Called Turbine Bypass)

a. Permits the nuclear plant to accept a sudden loss of load without incurring reactor trip. Steam is dumped to the condenser and/or the atmosphere, as

necessary, to accommodate excess power generation in the reactor during turbine load reduction transients.

b. Ensures that stored energy and residual heat are removed following a reactor trip to bring the plant to equilibrium no-load conditions without actuation of the steam generator safety valves.

c. Maintains the plant at no-load conditions and permits manually controlled cooldown of the plant.

Incore Instrumentation

Provides information on the neutron flux distribution and on the core outlet temperatures at selected core locations.

AMSAC

The ATWS Mitigation System Actuation Circuitry (AMSAC) automatically initiates auxiliary feedwater and a turbine trip under conditions indicative of an Anticipated Transient Without Scram (ATWS) event. AMSAC actuation ensures that RCS pressure will remain below the ASME B&PV Code Level C service limit stress criteria (3200 psig) after the most severe ATWS events (loss of external electrical load or loss of normal feedwater flow), per WCAP-8330 and Reference 3.

7.7.1.1 Reactor Control System

The reactor control system enables the nuclear plant to follow load changes automatically, including the acceptance of step load decreases of 10 percent and ramp decreases of 5 percent per minute over the entire power range without reactor trip, steam dump, or pressure relief (subject to possible xenon limitations). The system is also capable of allowing manual restoration of coolant average temperature to within the programmed temperature deadband following a change in load. Manual control rod operation may be performed at any time within the range of defined insertion limits. Automatic rod control operation provides automatic control rod insertion but does not allow automatic control rod withdrawal.

The reactor control system controls the reactor coolant average temperature by regulation of control rod bank position. The reactor coolant loop average temperatures are determined from hot leg and cold leg measurements in each reactor coolant loop. There is an average coolant temperature (T_{avg}) computed for each loop, where:

$$T_{avg} = \frac{T_{hot} + T_{cold}}{2}$$

The error between the programmed reference temperature (based on turbine impulse chamber pressure) and the highest of the T_{avg} measured temperatures (which is processed through a lead-lag compensation unit) from each of the reactor coolant loops constitutes the primary control signal, as shown in general on Figure 7.7-1 and in more detail on the functional diagrams shown in Figure 7.2-1 (Sheet 9). The system is capable of allowing manual restoration of coolant average temperature to the programmed value following a change in load. The programmed coolant temperature increases linearly with turbine load from zero power to the full power condition. For an evaluated T_{avg} based on positioning of AEHV0038 (high pressure feedwater heater bypass valve) the T_{avg} also supplies a signal to pressurizer level control and steam dump control and rod insertion limit monitoring.

The temperature channels needed to derive the temperature input signals for the reactor control system are fed from protection channels via isolation amplifiers.

An additional control input signal is derived from the reactor power versus turbine load mismatch signal. This additional control input signal improves system performance by enhancing response and reducing transient peaks.

The core axial power distribution is controlled during load follow maneuvers by changing (a manual operator action) the boron concentration in the RCS. The control board $\Delta\phi$ displays (see Section 7.7.1.3.1) indicate the need for an adjustment in the axial power distribution. Adding boron to the reactor coolant will reduce T_{avg} and will require the operator to manually withdraw control rods to restore T_{avg}. This action will reduce power peaks in the bottom of the core. Likewise, removing boron from the reactor coolant will move the rods further into the core to control power peaks in the top of the core.

7.7.1.2 Rod Control System

7.7.1.2.1 Description

The rod control system receives rod speed and insertion signals from the T_{avg} control system. The rod speed demand signal varies over the corresponding range of 3.75 to 45 inches per minute (6 to 72 steps/minute), depending on the magnitude of the input signal. Manual control is provided to move a control bank in or out at a prescribed fixed speed.

A permissive interlock C-5 (see Table 7.7-1) derived from measurements of turbine impulse chamber pressure prevents automatic rod withdrawal when the turbine load is below 15 percent. In the "AUTOMATIC" mode, the rods are inserted in a predetermined programmed sequence by the automatic programming with the control interlocks (see Table 7.7-1).

The shutdown banks are always in the fully withdrawn position during normal operation, and are moved to this position at a constant speed by manual control prior to criticality. A

reactor trip signal causes them to fall by gravity into the core. There are five shutdown banks.

The control banks are the only rods that can be inserted under automatic control. Each control bank is divided into two groups to obtain smaller incremental reactivity changes per step. All RCCAs in a group are electrically paralleled to move simultaneously. There is individual position indication for each RCCA.

Power to CRDMs is supplied by two motor generator sets operating from two separate 480 Volt, three phase busses. Each generator is the synchronous type and is driven by a 200-Hp induction motor. The ac power is distributed to the rod control power cabinets through the two series-connected reactor trip breakers.

The variable speed rod drive programmer affords the ability to insert small amounts of negative reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband, as well as furnishing rod insertion at high speed. A summary of the RCCA sequencing characteristics is given below.

a. Two groups within the same bank are stepped so that the relative position of the groups will not differ by more than one step.

b. The control banks are programmed so that withdrawal of the banks is sequenced in the following order; control bank A, control bank B, control bank C, and control bank D. The programmed insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank withdrawn (bank D) is the first control bank inserted.

c. The control bank withdrawals are programmed such that when the first bank reaches a preset position, the second bank begins to move out simultaneously with the first bank which continues to move toward its fully withdrawn position. When the second bank reaches a preset position, the third bank begins to move out, and so on. This withdrawal sequence continues until the unit reaches the desired power level. The control bank insertion sequence is the opposite.

d. Overlap between successive control banks is adjustable between 0 to 50 percent (0 and 115 steps), with an accuracy of ±1 step.

e. Rod speeds for either the shutdown banks or manual operation of the control banks are capable of being controlled between a minimum of 6 steps per minute and a maximum of 72 (+0, -10) steps per minute.

7.7.1.2.2 Features

Credible rod control equipment malfunctions which could potentially cause inadvertent positive reactivity insertions due to inadvertent rod withdrawal (automatic rod withdrawal is no longer available), incorrect overlap, or malpositioning of the rods are the following:

a. Failures in the manual rod controls:

   1. Rod motion control switch (in-hold-out)

   2. Bank selector switch

b. Failures in the overlap and bank sequence program control:

   1. Logic cabinet systems

   2. Power supply systems

<u>Failures in the manual rod controls</u>

1. Failure of the rod motion control switch

   The rod motion control switch is a three-position lever switch. The three positions are "In," "Hold," and "Out." These positions are effective when the bank selector switch is in manual. Failure of the rod motion control switch (contacts failing short or activated relay failures) would have the potential, in the worst case, to produce positive reactivity insertion by rod withdrawal when the bank selector switch is in the manual position or in a position which selects one of the banks.

   When the bank selector switch is in the automatic position, the rods would obey the automatic commands and failures in the rod motion control switch would have no effect on the rod motion regardless of whether the rod motion control switch is in "In," "Hold," or "Out" (automatic rod withdrawal is no longer available).

   In the case where the bank selector switch is selecting a bank and a failure occurs in the rod motion switch that would command the bank "Out" even when the rod motion control switch was in an "In" or "Hold" position the selected bank could inadvertently withdraw. This failure is bounded in the safety analysis (Chapter 15.0) by the uncontrolled bank withdrawal at subcritical and at power transients. A reactivity insertion of up to 85 pcm/sec is assumed in the analysis due to rod movement at hot zero power (110 pcm/sec at full power). This value of reactivity insertion rate is consistent with the withdrawal of two banks.

Failure that can cause more than one group of four mechanisms to be moved at one time within a power cabinet is not a credible event because the circuit arrangement for the movable and lift coils would cause the current available to the mechanisms to divide equally between coils in the two groups (in a power supply). The drive mechanism is designed so that it will not operate on half current. A second feature in this scenario would be the multiplexing failure detection circuit included in each power cabinet. This circuit would stop rod withdrawal (or insertion).

The second case considered in the potential for inadvertent reactivity insertion due to possible failures is when the selector switch is in the manual position. Such a case could produce, with a failure in the rod motion control switch, a scenario where the rods could inadvertently withdraw in a programmed sequence. The overlap and bank sequence are programmed when the selector switch is in either automatic or manual. This scenario is also bounded by the reactivity values assumed in the accident analysis. In this case, the operator can trip the reactor, or the protection system would trip the reactor via power range neutron flux-high, or overtemperature ΔT.

2. Failure of the bank selector switch

   A failure of the bank selector switch produces no consequences when the "in-hold-out" manual switch is in the "Hold" position. This is due to the following design feature:

   The bank selector switch is series wired with the in-hold-out lever switch for manual and individual control rod bank operation. With the in-hold-out lever switch in the "Hold" position, the bank selector switch can be positioned without rod movement.

<u>Failures in the overlap and bank sequence program control</u>

The rod control system design prevents the movement of the groups out of sequence as well as limiting the rate of reactivity insertion. The main feature that performs the function of preventing malpositioning produced by groups out of sequence is included in the block supervisory memory buffer and control. This circuitry accepts and stores the externally generated command signals. In the event of out of sequence input command to the rods while they are in movement, this circuit will inhibit the buffer memory from accepting the command. If a change of signal command appears, this circuit would stop the system after allowing the slave cyclers to finish their current sequencing. Failure of the components related to this system will also produce rod deviation alarm and insertion limit alarm. Failures within the system such as failures of supervisory logic cards, pulser cards, etc., will also cause an urgent alarm. An urgent alarm will be followed by the following actions:

Automatic de-energizing of the lift coil and reduced current energizing of the stationary gripper coils and movable gripper coils;

Activation of the alarm light (urgent failure) on the power supply cabinet front panel; and

Activation of rod control urgent failure annunciation window on the plant annunciator.

The urgent alarm is produced in general by:

Regulation failure detector;

Phase failure detector;

Logic error detector;

Multiplexing error detector; or

Interlock failure detector.

1. Logic cabinet failures

   The rod control system is designed to limit the rod speed control signal output to a value that causes the pulser (logic cabinet) to drive the control rod driving mechanism at 72 steps per minute. If a failure should occur in the pulses or the reactor control system, the highest stepping rate possible is 77 steps per minute, which corresponds to one step every 780 milliseconds. A commanded stepping rate higher than 77 steps per minute would result in "GO" pulses entering a slave cycler while it is sequencing its mechanisms through a 780 millisecond step. This condition stops the control bank motion automatically, and alarms are activated locally and in the control room. It also causes the affected slave cycler to reflect further "GO" pulses until it is reset.

   Failures that cause the 780 millisecond step sequence time to shorten will not result in higher rod speeds, since the stepping rate is proportional to the pulsing rate. Simultaneous failures in the pulser or rod control system and in the clock circuits that determine the 780 millisecond stepping sequence could result in higher CRDM speed; however, in the unlikely event of these simultaneous multiple failures the maximum CRDM operation speed would be no more than approximately 100 steps per minute due to mechanical limitation. This speed has been verified by tests conducted on the CRDMs.

   Failures causing movement of the rods out of sequence:

No single failure was discovered (Ref. 2) that would cause a rapid uncontrolled withdrawal of Control Bank D (taken as worst case) when operating in the automatic bank overlap control mode with the reactor at near full power output (automatic rod withdrawal is no longer available). The analysis revealed that many of the failures postulated were in a safe direction and that rod movement is blocked by the rod urgent alarm.

2. Power supply system failures

Analysis of the power cabinet disclosed no single component failures that would cause the uncontrolled withdrawal of a group of rods serviced by the power cabinet. The analysis substantiates that the design of a power cabinet is "fail-preferred" with regard to a rod withdrawal accident if a component fails. The end results of the failure is either that of blocking rod movement or that of dropping an individual rod or rods or a group of rods. No failure, within the power cabinet, which could cause erroneous drive mechanism operation will remain undetected. Sufficient alarm monitoring (including "urgent" alarm) is provided in the design of the power cabinet for fault detection of those failures which could cause erroneous operation of a group of mechanisms. As noted in the foregoing, diverse monitoring systems are available for detection of failures that cause the erroneous operation of an individual control rod drive mechanism.

In summary, no single failure within the rod control system can cause either reactivity insertions or mal-positioning of the control rods resulting in core thermal conditions not bounded by analyses contained in Chapter 15.0.

7.7.1.3 Plant Control Signals for Monitoring and Indicating

7.7.1.3.1 Monitoring Functions Provided by the Nuclear Instrumentation System

The power range channels are used to measure power level, axial flux imbalance, and radial flux imbalance. Suitable alarms are derived from these signals, as described below.

Basic power range signals are:

a. Total current from a power range detector (four signals from separate detectors); these detectors are vertical and have a total active length of 10 feet.

b. Current from the upper half of each power range detector (four signals).

c. Current from the lower half of each power range detector (four signals).

The following (including standard signal processing for calibration) are derived from these basic signals:

a. Indicated nuclear power (four signals).

b. Indicated axial flux imbalance ($\Delta\phi$), derived from upper half flux minus lower half flux (four signals).

Alarm functions derived are as follows:

a. Deviation (maximum minus minimum of four) in indicated nuclear power.

b. Upper radial tilt (maximum to average of four) on upper half currents.

c. Lower radial tilt (maximum to average of four) on lower half currents.

Nuclear power and axial imbalance are selectable for recording on strip charts on the control board. Indicators are provided on the control board for nuclear power and for axial flux imbalance.

The axial flux difference (AFD) imbalance deviation $\Delta\phi$ alarms are derived from the plant computer which determines the 1-minute averages of each of the operable excore detector outputs to monitor $\Delta\phi$ in the reactor core and alerts the operator immediately if the one-minute average AFDs for at least two operable excore channels are outside the AFD limits and thermal power is greater than 50% of rated thermal power. For periods during which the alarm on axial flux difference is inoperable, the axial flux difference is logged, as defined in Section 16.2.1. No power reduction is required during this period of manual surveillance.

Additional background information on the nuclear instrumentation system can be found in Reference 1.

7.7.1.3.2 Rod Position Monitoring

Two separate systems are provided to sense and display control rod position as described below:

a. Digital rod position indication system

The digital rod position indication system measures the actual position of each control rod, using a detector which consists of discrete coils mounted concentrically with the rod drive pressure housing. The coils are located axially along the pressure housing and magnetically sense the entry and presence of the rod drive shaft through its centerline. For each detector,

the coils are interlaced into two data channels, and are connected to the containment electronics (Data A and B) by separate multiconductor cables. By employing two separate channels of information, the digital rod position indication system can continue to function (at reduced accuracy) when one channel fails. Multiplexing is used to transmit the digital position signals from the containment electronics to the control board display unit.

The control board display unit contains a column of light-emitting-diodes (LEDs) for each rod. At any given time, the one LED illuminated in each column shows the position for that particular rod. Since shutdown rods are always fully withdrawn with the plant at power, their position is displayed to ±4 steps only from rod bottom to 18 steps and from 210 steps to 228 steps. All intermediate positions of the rod are represented by a single "transition" LED. Each rod of the control banks has its position displayed to ±4 steps throughout its range of travel.

Included in the system is a rod at bottom signal for each rod that operates a local alarm. Also a control room annunciator is actuated when any shutdown rod or control bank A rod is at bottom.

b. Demand position system

The demand position system counts pulses generated in the rod drive control system to provide a digital readout of the demanded bank position.

The demand position and digital rod position indication systems are separate systems, but safety criteria were not involved in the separation, which was a result only of operational requirements. Operating procedures require the reactor operator to compare the demand and indicated (actual) readings from the rod position indication system so as to verify operation of the rod control system.

7.7.1.3.3 Control Bank Rod Insertion Monitoring

When the reactor is critical, an indication of reactivity status in the core is the position of the control bank in relation to reactor power (as indicated by the reactor coolant system loop ΔT) and coolant average temperature. Insertion limits for the control banks are defined as a function of reactor power.

The purpose of the control bank rod insertion monitor is to give warning to the operator of excessive rod insertion. The monitor is comprised of two alarms:

a. The "low" alarm alerts the operator of an approach to the Rod Insertion Limits ; and

b. The "low-low" alarm alerts the operator to take actions required by the Technical Specifications to: (a) verify shutdown margin or add boron to the

reactor coolant system by any one of several alternate methods as described in Section 9.3.4.2.3.4 and (b) restore the control banks to within their insertion limits.

The Rod Insertion Limit maintains sufficient core reactivity shutdown margin following reactor trip, provides a limit on the maximum reactivity addition (ejected rod worth) in the unlikely event of a hypothetical rod ejection, and limits rod insertion so that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased (the rods must be withdrawn further) with increasing power. Two parameters which are proportional to power are used as inputs to the insertion monitor. These are the ΔT between the hot leg and the cold leg, which is a direct function of reactor power, and T_{avg}, which is programmed as a function of power.

The rod insertion monitor uses parameters for each control rod bank as follows:

$$Z_{LL} = A(\Delta T)_{auct} + B(T_{avg})_{auct} + C \leq \text{Maximum Value}$$

where:

Z_{LL}	=	Low-Low alarm setpoint;
$(\Delta T)_{auct}$	=	highest ΔT of all loops;
$(T_{avg})_{auct}$	=	highest T_{avg} of all loops;
A, B, C	=	constants chosen to maintain rod insertion above the actual Rod Insertion Limit based on physics calculations; and

Maximum Value = a limit imposed on Z_{LL} when an individual control rod bank is required to be fully withdrawn based on power level.

The control rod bank demand position (Z) is compared to Z_{LL} as follows:

If $Z - Z_{LL} \leq D$, a low alarm is actuated; and

If $Z - Z_{LL} \leq E$, a low-low alarm is actuated.

Since the highest values of T_{avg} and ΔT are chosen by auctioneering, a conservatively high representation of power is used in the insertion limit calculation.

The value for "D" is chosen to alert the operator of an approach to the Rod Insertion Limit. The value for "E" is chosen so that the low-low alarm would normally be actuated before the insertion limit is exceeded.

Functionally, the control rod bank that is not required to be in the fully withdrawn position, based on power level, is the bank that will produce the alarms. At high power, that would be control bank D, whereas at low power it would be control banks A, B, or C. Upon a demand to step rods in, the overlap function ensures that the first bank to insert is the bank that is not required to be fully withdrawn. Thus, due to the operation of the overlap function, the monitor provides the operator with correct notification that the insertion limit is being approached or exceeded.

If a bank is operated in the individual bank select mode, the overlap counter does not function. Therefore, the rod insertion monitor does not work correctly for that bank, if power level is such that that bank is required to be withdrawn. This is only done during surveillance testing, troubleshooting, or recovery of a partially dropped rod. During such evolutions, the operators' attention is directed toward the control rods.

The Maximum Value is applied to eliminate invalid alarms when rods are fully withdrawn. The rods can be operated at any position above the Rod Insertion Limit, and be fully withdrawn. Without the Maximum Value feature, the low alarm would continuously be actuated for the control banks that are required to be fully withdrawn due to power level. In addition, analog instrument loop calibration tolerances could also lead to invalid low-low alarms for these banks. During control rod surveillance testing, the Maximum Value feature is also needed to allow the alarms to reset after the surveillance is completed.

Figure 7.7-2 shows a block diagram representation of the control rod bank insertion monitor. The monitor is shown in more detail on the functional diagrams shown in Figure 7.2-1 (Sheet 9). In addition to the rod insertion monitor for the control banks, the plant computer, which monitors individual rod positions, provides an alarm that is associated with the rod deviation alarm discussed in Section 7.7.1.3.4 to warn the operator if any shutdown RCCA leaves the fully withdrawn position.

Rod insertion limits are established by:

a. Establishing the allowed rod reactivity insertion at full power consistent with the purposes given above.

b. Establishing the differential reactivity worth of the control rods when moved in normal sequence.

c. Establishing the change in reactivity with power level by relating power level to rod position.

d. Linearizing the resultant limit curve. All key nuclear parameters in this procedure are measured as part of the initial and periodic physics testing program.

Any unexpected change in the position of the control bank under automatic control, or a change in coolant temperature under manual control, provides a direct and immediate

indication of a change in the reactivity status of the reactor. In addition, samples are taken periodically of coolant boron concentration. Variations in concentration during core life provide an additional check on the reactivity status of the reactor, including core depletion.

7.7.1.3.4 Rod Deviation Alarm

The position of any control rod is compared to the position of other rods in the bank. A rod deviation alarm is generated by the digital rod position indication system if a preset rod deviation limit is exceeded. The deviation alarm of a shut-down rod is based on a preset insertion limit being exceeded.

The demanded and measured rod position signals are also monitored by the plant computer which provides a visual printout and an audible alarm whenever an individual rod position signal deviates from the other rods in the bank by a preset limit. The alarm can be set with appropriate allowance for instrument error and within sufficiently narrow limits to preclude exceeding core design hot channel factors.

Figure 7.7-3 is a block diagram of the rod deviation comparator and alarm system implemented by the plant computer. Additionally, the digital rod position indication system contains rod deviation circuitry that detects and alarms the following conditions:

a. When any two rods within the same control bank are misaligned by a preset distance (≥ 12 steps), and

b. When any shutdown rod is below the full-out position by a preset distance (18 steps).

7.7.1.3.5 Rod Bottom Alarm

The rod bottom signal for the control rods in the digital rod position indication system is used to operate a control relay, which generates the "ROD BOTTOM ROD DROP" alarm.

7.7.1.4 <u>Plant Control System Interlocks</u>

The listing of the plant control system interlocks, along with the description of their derivations and functions, is presented in Table 7.7-1. The designation numbers for these interlocks are preceded by "C." The development of these logic functions is shown in the functional diagrams (see Figure 7.2-1, Sheets 9 through 16).

7.7.1.4.1 Rod Stops

Rod stops are provided to prevent abnormal power conditions which could result from excessive control rod withdrawal initiated by operator violation of administrative procedures.

Rod stops are the C-l, C-2, C-3, and C-4 control interlocks identified in Table 7.7-1. The C-5 and C-11 control interlocks identified in Table 7.7-1 are associated with automatic rod withdrawal which is no longer available at Callaway. The C-3 rod stop derived from overtemperature ΔT and the C-4 rod stop derived from overpower ΔT are also used for turbine runback, which is discussed below.

7.7.1.4.2 Automatic Turbine Load Runback

Automatic turbine load runback is initiated by an approach to an overpower or overtemperature condition. This will prevent high power operation that might lead to an undesirable condition, which, if reached, will be protected by reactor trip.

Turbine load reference reduction is initiated by either an overtemperature or overpower ΔT signal. Two-out-of-four coincidence logic is used.

A rod stop and turbine runback are initiated when

$$\Delta T > \Delta T_{\text{rod stop}}$$

for both the overtemperature and the overpower condition.

For either condition in general

$$\Delta T_{\text{rod stop}} = \Delta T_{\text{setpoint}} - B_p$$

where:

B_p = a setpoint bias

where ΔT setpoint refers to the overtemperature ΔT reactor trip value and the overpower ΔT reactor trip value for the two conditions.

The turbine runback is continued until ΔT is equal to or less than $\Delta T_{\text{rod stop}}$.

This function serves to maintain an essentially constant margin to trip.

7.7.1.5 <u>Pressurizer Pressure Control</u>

The reactor coolant system pressure is controlled by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer plus steam relief for large transients.

The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater group is proportionally controlled to correct small pressure variations. These variations are caused by heat losses, including heat losses due to a

small continuous spray. The remaining (back-up) heaters are turned on when the pressurizer pressure controlled signal demands approximately 100-percent proportional heater power.

The spray nozzle is located on the top of the pressurizer. Spray is initiated when the pressure controller spray demand signal is above a given setpoint. The spray rate increases proportionally with increasing spray demand signal until it reaches a maximum value.

Steam condensed by the spray reduces the pressurizer pressure. A small continuous spray is normally maintained to reduce thermal stresses and thermal shock and to help maintain uniform water chemistry and temperature in the pressurizer.

Power relief valves limit system pressure for large positive pressure transients. In the event of a large load reduction, not exceeding the design plant load rejection capability, the pressurizer power-operated relief valves might be actuated for the most adverse conditions, e.g., the most negative Doppler coefficient and the maximum incremental rod worth. The relief capacity of the power-operated relief valves is sized large enough to limit the system pressure to prevent actuation of high pressure reactor trip for the above condition. The automatic actuation circuitry for the PORVs has been upgraded to Class 1E.

A block diagram of the pressurizer pressure control system is shown on Figure 7.7-4.

7.7.1.6 Pressurizer Water Level Control

The pressurizer operates by maintaining a steam cushion over the reactor coolant. As the density of the reactor coolant varies with temperature, the steam water interface is adjusted to compensate for cooling density variations with relatively small pressure disturbances.

The water inventory in the reactor coolant system is maintained by the chemical and volume control system. During normal plant operation, the charging flow varies to produce the flow demanded by the pressurizer water level controller. The pressurizer water level is programmed as a function of coolant average temperature, with the highest average temperature (auctioneered) being used. The pressurizer water level decreases as the load is reduced from full load. This is a result of coolant contraction following programmed coolant temperature reduction from full power to low power. The programmed level is designed to match as nearly as possible the level changes resulting from the coolant temperature changes.

To control pressurizer water level during startup and shutdown operations, the charging flow is manually regulated from the main control room. The letdown line isolation valves are closed on low pressurizer level.

A block diagram of the pressurizer water level control system is shown on Figure 7.7-5.

7.7.1.7 Steam Generator Water Level Control

Each steam generator is equipped with a three-element feedwater flow controller which maintains a programmed water level which is a function of turbine load. The three-element feedwater controller regulates the feedwater valve by continuously comparing the feedwater flow signal, the water level signal, the programmed level, and the pressure compensated steam flow signal. The feedwater pump speed is varied to maintain a programmed pressure differential between the steam header and the feedwater pump discharge header. The speed controller continuously compares the actual ΔP with a programmed ΔP_{ref} which is a linear function of steam flow. The median of three feedwater header pressure inputs is used to develop a feedwater header pressure input to the digital feedwater control system (DFWCS). Similarly, the median of three steam header pressure inputs is used to develop a steam header pressure input to the digital feedwater control system, and the median of three main feedwater pump speed inputs is used to develop a pump speed input to the digital feedwater control system. This allows the loss of a single input without adversely impacting the control system. Failure or excessive drifting of an input results in the control system switching to the average of the remaining two signals. Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor following a reactor trip and turbine trip. An override signal (P-4 coincident with low T_{avg}) closes all feedwater valves, if not bypassed, when the average coolant temperature is below a given temperature and the reactor has tripped (not part of the primary success path for any accident's mitigation in Chapter 15). Manual override of the feedwater control system is available at all times. Five means are provided to override the control signal from the steam generator water level control system:

a. Manual control

b. Low-low SG water level (ensures AFW delivery for residual and decay heat removal)

c. High-high SG water level (prevents SG overfill and excessive moisture carryover to the turbine)

d. P-4 coincident with low T_{avg} (back-up protection against excessive RCS cooldown)

e. SIS (lessens severity of secondary line breaks inside containment by isolating main feedwater flow).

These override features are shown on Figure 7.2-1, sheets 13 and 14.

When the nuclear plant is operating at very low power levels (as during startup), the steam and feedwater flow signals will not be usable for control. Therefore, a secondary automatic control system is provided for operation at low power. This system uses the

steam generator water level and nuclear power signals in a feed forward control scheme to position a bypass valve which is in parallel with the main feedwater regulating valve. Switchover from the bypass feedwater control system (low power) to the main feedwater control system is initiated by the operator at approximately 25 percent power, and can be completed either automatically by the DFWCS or manually by the control room operators.

Block diagrams of the steam generator water level control system and the main feedwater pump speed control system are shown in Figures 7.7-6 and 7.7-7.

7.7.1.8 Steam Dump Control

The steam dump system, together with control rod movement, is designed to accept a 50-percent loss of net load without tripping the reactor.

The automatic steam dump system is able to accommodate this abnormal load rejection and to reduce the effects of the transient imposed upon the reactor coolant system. By bypassing main steam directly to the condenser, an artificial load is thereby maintained on the primary system. The rod control system can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The steam dump steam flow capacity is 40 percent of full load steam flow at full load steam pressure.

If the difference between the reference T_{avg} (T_{ref}) based on turbine impulse chamber pressure and the lead-lag compensated auctioneered T_{avg} exceeds a predetermined amount, and the interlock mentioned below is satisfied, a demand signal will actuate the steam dump to maintain the reactor coolant system temperature within control range until a new equilibrium condition is reached.

To prevent actuation of steam dump on small load perturbations, an independent load rejection sensing circuit is provided. This circuit senses the rate of decrease in the turbine load, as detected by the turbine impulse chamber pressure. It is provided to unblock the dump valves when the rate of load rejection exceeds a preset value corresponding to a 10-percent step load decrease or a sustained ramp load decrease of 5 percent per minute.

A block diagram of the steam dump control system is shown on Figure 7.7-8.

7.7.1.8.1 Load Rejection Steam Dump Controller

This circuit prevents a large increase in reactor coolant temperature following a large, sudden load decrease. The error signal is a difference between the lead-lag compensated auctioneered T_{avg} and the reference T_{avg} based on turbine impulse chamber pressure.

Operation at reduced Tavg has been evaluated. Reduced T_{avg} operation may occur for: (a) normal power operation as described in Section 10.4.7.2.3, or (b) Tavg coastdown operation as described in Section 15.0.2.2. In the case of normal power reduced Tavg operation, the evaluated value of Tavg must be implemented in the control system for proper controller function. For Tavg coastdown operation, the evaluated value of Tavg is not required to be implemented; however, the load rejection controller gain and steam dump valve open setpoints will require adjustment as described in Section 15.0.2.2.

The T_{avg} signal is the same as that used in the reactor coolant system. The lead-lag compensation for the T_{avg} signal is to compensate for lags in the plant thermal response and in valve positioning. Following a sudden load decrease, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating an immediate demand signal for steam dump. Since control rods are available in this situation, steam dump terminates as the error comes within the maneuvering capability of the control rods.

7.7.1.8.2 Plant Trip Steam Dump Controller

Following a reactor trip, the load rejection steam dump controller is defeated, and the plant trip steam dump controller becomes active. Since control rods are not available in this situation, the demand signal is the error signal between the lead-lag compensated auctioneered T_{avg} and the no-load reference T_{avg}. When the error signal exceeds a predetermined setpoint, the dump valves are tripped open in a prescribed sequence. As the error signal reduces in magnitude, indicating that the RCS T_{avg} is being reduced toward the reference no-load value, the dump valves are modulated by the plant trip controller to regulate the rate of removal of decay heat and thus gradually establish the equilibrium hot shutdown condition.

7.7.1.8.3 Steam Header Pressure Controller

Residual heat removal at operating temperature is maintained by the steam generator pressure controller (manually selected) which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers which are used during the initial transient following turbine or reactor trip on load rejection.

7.7.1.9 Incore Instrumentation

The incore instrumentation system consists of chromel-alumel thermocouples (described in Section 18.2.13.2) at fixed core outlet positions and movable miniature neutron detectors which can be positioned at the center of selected fuel assemblies, anywhere along the length of the fuel assembly vertical axis. The basic system for insertion of these detectors is shown in Figure 7.7-9.

7.7.1.9.1 Thermocouples

Chromel-alumel thermocouples are threaded into guide tubes that penetrate the reactor vessel head through seal assemblies, and terminate at the exit flow end of the fuel assemblies. The thermocouples are provided with two primary seals--a conoseal and compression-type seal from conduit to head. Thermocouple readings are monitored by the computer.

7.7.1.9.2 Movable Neutron Flux Detector Drive System

Miniature fission chamber detectors can be remotely positioned in retractable guide thimbles to provide flux-mapping of the core. The stainless steel detector shell is welded to the leading end of the helical wrap drive cable and to stainless steel sheathed coaxial cable. The retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits which extend from the bottom of the reactor vessel down through the concrete shield area and then up to a thimble seal table. Their distribution over the core is nearly uniform with about the same number of thimbles located in each quadrant.

The thimbles are closed at the leading ends, are dry inside, and serve as the pressure barrier between the reactor water pressure and the atmosphere. For each thimble, an in-line magnetic isolation ball check valve, located above the seal table, provides a second barrier between the reactor water pressure and the atmosphere. Mechanical seals between the retractable thimbles and the conduits are provided at the seal table. During reactor operation, the retractable thimbles are stationary. They are extracted downward from the core during refueling to avoid interference within the core. A space above the seal table is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists basically of drive assemblies, 6-path transfer assemblies, and 15-path transfer assemblies, as shown in Figure 7.7-9. The drive system pushes hollow helical wrap drive cables into the core with the miniature detectors attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor which pushes a helical wrap drive cable and a detector through a selective thimble path by means of a special drive box and includes a storage device that accommodates the total drive cable length. Each detector has access to all thimble locations via the 6- and 15-path rotary assemblies.

7.7.1.9.3 Control and Readout Description

The control and readout system provides means for inserting the miniature neutron detectors into the reactor core and withdrawing the detectors while plotting neutron flux versus detector position. The control system is located in the control room. Limit switches in each transfer device provide feedback of path selection operation. Each gear box drives a resolver for position feedback. One 6-path transfer selector is provided

for each drive unit to insert the detector in one of six functional modes of operation. One 15-path transfer is also provided for each drive unit that is then used to route a detector into any one of up to 15 selectable paths. A common path is provided to permit cross calibration of the detectors.

The control room contains the necessary equipment for control, position indication, and flux recording for each detector.

A "flux-mapping" consists, briefly, of selecting flux thimbles in given fuel assemblies at various core quadrant locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot (position versus flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. In a similar manner, other core locations are selected and plotted. Each detector provides axial flux distribution data along the center of a fuel assembly.

Various radial positions of detectors are then compared to obtain a flux map for a region of the core.

The number and location of these thimbles have been chosen to permit measurement of local-to-average peaking factors to an accuracy of ±5 percent (95-percent confidence). Measured nuclear peaking factors will be increased by 5 percent to allow for this accuracy. If the measured power peaking is larger than acceptable, reduced power capability will be indicated.

Operating plant experience has demonstrated the adequacy of the incore instrumentation in meeting the design bases stated.

7.7.1.9.4 Power Distribution Monitoring System

As an enhancement to power distribution measurement and indication capability, the power distribution monitoring system (PDMS) is provided, which consists of a set of coupled but independent computer software programs that execute on one or more workstations to generate an on-line, three-dimensional indication of the core power distribution. The PDMS uses the flux map together with a three-dimensional analytical model to yield the continuously measured three-dimensional power distribution. The movable incore neutron detectors are used to calibrate the PDMS.

7.7.1.10 Boron Concentration Monitoring System

The boron concentration monitoring system utilizes a sampler assembly unit which contains a neutron source and neutron detector located in a shield tank. A thermal neutron absorption technique is used. Piping within the shield tank is arranged to provide coolant sample flow between the neutron source and the neutron detector. Neutrons originating at the source are thermalized in the sample and the surrounding moderator. These neutrons then pass through the sample and impinge upon the detector. The number of neutrons which survive the transit from the source to the

detector is inversely proportional to the boron concentration in the sample. The boron concentration is calculated by monitoring the neutron countrate in conjunction with the proper transfer function. The neutron cross-section of the boron in the sample is also a function of the neutron energy and, subsequently, the sample temperature. Therefore, the sample temperature is also monitored and the transfer function from the neutron countrate to boron concentration modified to compensate for the variance of temperature.

The processor assembly is used to convert the neutron countrate and temperature data from the sampler assembly to parts per million (ppm) of boron, and to prepare the data for local and remote display. The system characteristics are listed in Table 7.7-2.

a. Sampler assembly

The sampler assembly consists of a polyethylene cylinder encased in a stainless steel liner (see Figure 7.7-10). The polyethylene serves as a neutron moderator and shield. A cavity (source tube) is located in the center of the shield into which is inserted a neutron source on the end of a polyethylene rod (source plug). Immediately adjacent to the source tube is a second larger cavity into which an annulus assembly and a top plug assembly are inserted. Details of these two assemblies are shown in Figure 7.7-11.

The annulus assembly consists of two concentric tubes with top and bottom plates. A neutron detector is positioned inside the smaller tube. The coolant sample is circulated between the concentric tubes. The sample is brought into and taken out of the annular region via tubes provided for connection to plant piping. The entire assembly is made of stainless steel.

The top plug assembly consists of a polyethylene plug with appropriate ports for the input and output tubes and the detector signal cable. A stainless steel top plate is provided for mounting to the sampler assembly.

b. Processor assembly

The processor assembly controls the operation of the system. It processes the neutron countrate and temperature data from the sampler assembly, displays the calculated boron concentration, and transmits the result for remote display. A block diagram which depicts the functional operation of the processor assembly is shown in Figure 7.7-12. The neutron countrate and sample temperature measurements are processed to a microprocessor. The microprocessor repeatedly solves an algorithm to convert the input information to a boron concentration measurement. In order to make the above calculation, several constants are required. These constants are determined by calibration and are entered in the

microprocessor by manual interactions with a keypad. The display unit presents the calculated boron concentration in units of ppm in integer format.

c. Remote display assembly

The function of this unit is to display the boron concentration at a location (usually in the control room) remote from the processor assembly. This remote display may be located up to 1,000 feet from the processor assembly. Boron concentration data generated at the process assembly is transmitted over a twisted shielded pair. The remote display assembly contains the circuits necessary to decode and display the data.

The boron concentration monitoring system is designed for use as an advisory system. It is not designed as a safety system or component of a safety system. The boron concentration monitoring system is not part of a control element or control system, nor is it designed for this use. No credit is taken for this system in any accident analysis. Therefore, redundancies of measurement components, self checking subsystems, malfunction annunciations, and diagnostic circuitry are not included in this system. However, watchdog circuitry provides the operator with appropriate indication if the data becomes stale or frozen. As a general operating aid, it provides information as to when additional check analyses are warranted, rather than a basis for fundamental operating decisions. During normal plant operations, the boron concentration varies between 0 and 1,800 ppm. The boron concentration monitoring system operates within a ±10 ppm range.

7.7.1.11 ATWS Mitigation System Actuation Circuitry

The ATWS Mitigation System Actuation Circuitry (AMSAC) automatically initiates auxiliary feedwater flow, isolates Steam Generator blowdown and sample lines, and initiates a turbine trip under conditions indicative of an Anticipated Transient Without Scram (ATWS) event.

7.7.1.11.1 SYSTEM DESCRIPTION

The AMSAC equipment is located in the control room and consists of logic assemblies, isolation devices, and interconnecting cables interfacing with other plant equipment.

Four Reactor Protection System (RPS) narrow range steam generator level loops and two RPS turbine impulse pressure loops provide inputs to AMSAC from the 7300 racks. The AMSAC logic outputs go to the Balance of Plant (BOP) Engineered Safety Features Actuation System (ESFAS) and Turbine Generator ElectroHydraulic Control (EHC) cabinets.

An AMSAC actuation occurs when 3 out of 4 steam generator narrow range level signals fall below the AMSAC setpoint (9% of span) for more than 25 seconds and both turbine impulse pressure signals are above 40% reactor power (1432 MWt), which enables the C-20 permissive. The AMSAC is armed (C-20 permissive) above 40% reactor power and disabled 360 seconds after 1 out of 2 power signals falls below 40%. The 25 second AMSAC time delay allows the RPS to operate first. Whereas AMSAC must be armed above 40% reactor power, the actual setpoint has been established as 34.9% reactor power to allow for instrument loop inaccuracy.

An AMSAC actuation causes the BOP-ESFAS system to start the AFW pumps, close the steam generator blowdown isolation valves and close the steam generator sample isolation valves. The safety-related systems (RPS and BOP-ESFAS) are isolated from AMSAC through qualified isolation devices, as shown on Figure 7.7-16. AMSAC also provides signals to the EHC cabinets which energize the 125 Vdc trip bus and trip the turbine.

AMSAC provides two main control board annunciators and several local indicating lights. One control room annunciator (normally de-energized; energize to alarm) indicates that an AMSAC actuation will occur after a 25 second time delay (AMSAC pre-trip alarm) and the other annunciator (normally energized; de-energize to alarm) is an AMSAC panel trouble alarm that indicates several miscellaneous AMSAC trouble conditions (e.g., C-20 permissive circuitry fails to arm above 40% reactor power, master bypass switch closed for test or maintenance, operating bypass switch closed for testing individual logic inputs, electronic module out of service, monitor module logic test, loss of power supply, or self diagnostics indicate logic assembly failure).

The local indicating lights on the AMSAC logic cabinet include:

a. AMSAC pre-trip light

b. AMSAC panel trouble light (illuminated when any of the above AMSAC panel trouble control room annunciator conditions exist)

c. 5 bypass lights (one master bypass light, 3 individual logic assembly bypass lights, and one operating bypass light for testing individual logic inputs)

d. AMSAC logic trouble light (illuminated when any of the logic assemblies fail or when the C-20 permissive circuitry fails to arm above 38% reactor power)

e. AMSAC armed light (C-20 permissive)

f. power supply trouble light

g. 9 logic assembly, individual relay status (partial trip) lights

h. 3 logic assembly output trip lights

i. electronic module out of service light

AMSAC cannot be manually reset by the operators until after its mitigating actions are completed. AMSAC actuates automatically; there is no manual AMSAC initiation. AMSAC is automatically armed above 40% power and bypassed below 40% power.

AMSAC initiates auxiliary feedwater flow within 90 seconds of an ATWS event and a turbine trip within 30 seconds of an ATWS event (including sensor and relay delays).

AMSAC utilizes three identical logic assemblies, diverse from the SSPS, and a 2 out of 3 actuation logic to prevent inadvertent trips due to the AMSAC circuitry and improve reliability. Testing of AMSAC through the final actuation devices will be performed every refueling outage.

References 3-5 provide additional discussions on AMSAC diversity from the RPS, logic power supplies, safety-related interfaces via Class 1E isolation devices, graded QA program, maintenance and testing bypasses via permanently installed bypass switches annunciated by the previously mentioned trouble alarm, electrical independence and physical separation from the RPS, testability at power in bypass, and completion of mitigative action once initiated. The steam generator level sensors used for input to AMSAC are different than those used to drive the steam generator level control system, thereby precluding adverse control system interactions. The logic power supply, 125 Vdc, is independent from the RPS power supplies. AMSAC is capable of performing its intended function upon a loss of offsite power. Removal of the C-20 permissive signal is delayed by 360 seconds to avoid blocking AMSAC before it can perform its function in the event a turbine trip occurs. Existing protection system level transmitters, sensing lines, and sensor power supplies are used for input to AMSAC. Input isolation is attained via 7300 isolation cards; output isolation is attained via isolation relays before going to the BOP-ESFAS. AMSAC output can be disabled via the master bypass switch to avoid actuation during maintenance and testing. Each of the three logic assemblies is also provided with an individual bypass switch to permit troubleshooting and repair. The AFW actuation and turbine trip relay contacts are normally open; these are energize to trip functions.

7.7.1.11.2 NONSAFETY-RELATED QUALITY ASSURANCE PROGRAM FOR AMSAC EQUIPMENT

The Quality Assurance Program for Nonsafety-Related AMSAC Equipment invokes certain criteria of 10CFR50 Appendix B. This section uses guidance that was developed by the NRC to assist the industry in compliance with the requirements of 10CFR50.62(d). The objective of this section is to provide a description of quality assurance criteria applicable to the reliable operation of the AMSAC equipment. This program replaces the one described by ULNRC 1472 attachment 1.

7.7.1.11.2.1 ORGANIZATION

Callaway Plant's existing line organizations are responsible for compliance with this program. No separate or unique organization is required to implement the requirements of this program.

7.7.1.11.2.2 PROGRAM

The Plant procedures provide the requirements for implementing this nonsafety-related quality assurance program. These procedures are also used to implement the requirements of this program.

7.7.1.11.3 DESIGN CONTROL

Design control shall involve measures to ensure design specification are included or translated into design documents. Safety evaluations shall be performed as required by 10CFR50.59, for design activities. Normal supervisory review of a designer's work is considered an adequate control measure.

Design control for contractor and subcontractor organizations requires no additional controls other than those Callaway Plant imposes on its own design control.

7.7.1.11.4 PROCUREMENT DOCUMENT CONTROL

Provisions shall be established to ensure system specifications and quality requirements, where applicable, are included in procurement documents.

7.7.1.11.5 INSTRUCTIONS, PROCEDURES AND DRAWINGS

Activities associated with nonsafety-related AMSAC equipment shall be accomplished in accordance with documented instructions, procedures, drawings, checklists or any methodology which provides the appropriate degree of guidance to personnel performing quality related activities.

Maintenance conducted on equipment under this program shall be planned, controlled by procedures, and documented. Work shall be based on vendor information. Any departure from vendor guidance shall be based on adequate engineering rationale.

7.7.1.11.6 DOCUMENT CONTROL

Controls shall be established to control changes to documents affecting quality.

7.7.1.11.7 CONTROL OF PURCHASED MATERIAL, EQUIPMENT AND SERVICES

Measures shall be established to ensure all purchases conform to the appropriate procurement documents. Acceptance by receipt inspection may be used as a means of item acceptance.

7.7.1.11.8 IDENTIFICATION AND CONTROL OF MATERIALS, PARTS AND COMPONENTS

The identification and control of materials, parts and components shall be accomplished in accordance with station procedures and apply to materials, parts, and components during storage, installation or use. These procedures shall address control of storage of environmentally sensitive equipment or material and storage of equipment or material that has a limited shelf-life.

7.7.1.11.9 SPECIAL PROCESSES

Measures shall be establised to control special processes. Examples of processes that shall be controlled include welding, heat treating and non-destructive testing. Applicable codes, standards, specifications, criteria and other special requirements may serve as the basis of these controls.

7.7.1.11.10 INSPECTION

Inspections shall be established for activities affecting quality. Inspections are performed to verify these activities conform to available documentation, or, if no documentation is available, to verify the activities are being satisfactorily accomplished. The line organization is responsible for determining the inspection requirements and for ensuring that sufficient inspections are performed. Inspections need not be performed by individuals independent of the line organization. Inspections shall be performed by knowledgeable individuals.

7.7.1.11.11 TEST CONTROL

Testing shall be performed periodically and the results evaluated to ensure testing requirements have been satisfied. Testing frequency shall be prescribed by the plant procedures, as opposed to the Technical Specifications.

7.7.1.11.12 CONTROL OF MEASURING AND TEST EQUIPMENT

Controls shall be established to control, calibrate and adjust, measuring and test equipment at specific intervals.

7.7.1.11.13 HANDLING, STORAGE AND SHIPPING

Measures shall be establised to control, handling, storage, shipping, cleaning and preservation of purchases in accordance with Callaway Plant practices and manufacturer's recommendations.

7.7.1.11.14 INSPECTION, TEST AND OPERATING STATUS

Measures shall be established to indicate status of inspection, test and operability of installed nonsafety-related AMSAC equipment.

7.7.1.11.15 NONCONFORMING MATERIAL, PARTS OR COMPONENTS

Material nonconformances shall be identified and controlled in accordance with the requirements of Callaway Plant procedures. The reporting requirements of 10CFR21 do not apply to nonsafety-related AMSAC equipment.

7.7.1.11.16 CORRECTIVE ACTION

Measures shall be established for the prompt correction of conditions adverse to quality and to preclude the repetition of conditions adverse to quality.

7.7.1.11.17 RECORDS

Measures shall be establised to maintain and control records of activities in accordance with the requirements of 10CFR50.59. Measures shall be established to maintain and control appropriate records to ensure that the requirements specified in the table accompanying the ATWS rule (49 FR 26036, pp 26042-26043) have been met.

7.7.1.11.18 AUDITS

Independent audits are not required, if line management periodically reviews the adequacy of the quality controls and takes any necessary corrective action. Line management is responsible for determining whether reviews conducted by line management or audits conducted by an organization independent of line management is appropriate

7.7.2 ANALYSIS

The plant control systems are designed to assure high reliability in any anticipated operational occurrences. Equipment used in these systems is designed and constructed with a high level of reliability.

Proper positioning of the control rods is monitored in the control room by bank arrangements of the individual position columns for each RCCA. A rod deviation alarm alerts the operator of a deviation of one RCCA from the other rods in that bank position.

There are also insertion limit monitors with visual and audible annunciation. A rod bottom alarm signal is provided to the control room for each RCCA. Four excore long ion chambers also detect asymmetrical flux distribution indicative of rod misalignment.

Overall reactivity control is achieved by the combination of soluble boron and RCCAs. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant. Short-term reactivity control for power changes is accomplished by the RCCAs.

The axial core power distribution is controlled by moving the control rods through changes in RCS boron concentration. Adding boron will reduce T_{avg} and require the operator to manually withdraw control rods, thereby reducing the amount of power in the bottom of the core. This allows power to redistribute toward the top of the core. Reducing the boron concentration causes the rods to move into the core, thereby reducing the power in the top of the core. As a result, power is redistributed toward the bottom of the core.

The plant control systems will prevent an undesirable condition in the operation of the plant that, if reached, will be protected by reactor trip. The description and analysis of this protection is covered in Section 7.2. Worst-case failure modes of the plant control systems are postulated in the analysis of off-design operational transients and accidents covered in Chapter 15.0, such as, the following:

a. Uncontrolled RCCA bank withdrawal from a subcritical or low power startup condition.

b. Uncontrolled RCCA bank withdrawal at power.

c. RCCA misoperation.

d. Loss of external electrical load and/or turbine trip.

e. Loss of all nonemergency ac power to the station auxiliaries.

f. Feedwater system malfunctions that result in a decrease in feedwater temperature.

g. Excessive increase in secondary steam flow.

h. Inadvertent opening of a steam generator relief or safety valve.

These analyses show that a reactor trip setpoint is reached in time to protect the health and safety of the public under those postulated incidents and that the resulting coolant temperatures produce a DNBR well above the applicable limiting value. Thus, there will be no cladding damage and no release of fission products to the RCS under the assumption of these postulated worst-case failure modes of the plant control system.

7.7.2.1 Separation of Protection and Control System

In some cases, it is advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel. As such, a failure in the control circuitry does not adversely affect the protection channel. Test results have shown that a short circuit or the application (credible fault voltage from within the cabinets) of 120 Volt ac or 140 Volt dc on the isolated output portion of the circuit (nonprotection side of the circuit) will not affect the input (protection) side of the circuit.

Where a single random failure can cause a control system action that results in a generating station condition requiring protective action and can also prevent proper action of a protection system channel designed to protect against the condition, the remaining redundant protection channels are capable of providing the protective action even when degraded by a second random failure. This meets the applicable requirements of Section 4.7 of IEEE Standard 279-1971.

The pressurizer pressure channels needed to derive the protection signals are electrically isolated from control.

7.7.2.2 Response Considerations of Reactivity

Reactor shutdown with control rods is completely independent of the control functions since the trip breakers interrupt power to the CRDMs, regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of control groups or unplanned dilution of soluble boron without exceeding acceptable fuel design limits. The design meets the requirements of GDC-25.

No single electrical or mechanical failure in the rod control system could cause the accidental withdrawal of a single RCCA from the partially inserted bank at full power operation. The operator could deliberately withdraw a single RCCA in the control bank; this feature is necessary in order to retrieve a rod, should one be accidentally dropped. In the extremely unlikely event of simultaneous electrical failures which could result in single RCCA withdrawal, rod deviation would be displayed on the plant annunciator, and the individual rod position readouts would indicate the relative positions of the rods in the bank. Withdrawal of a single RCCA by operator action, whether deliberate or by a combination of errors, would result in activation of the same alarm and the same visual indications.

Each bank of control rods (A-D) and shutdown banks SA and SB (See Figure 4.3-36) in the system are divided into two groups (group 1 and group 2) of up to four or five mechanisms each. In the banks with two groups, the rods comprising a group operate in parallel through multiplexing thyristors. The two groups in these banks move sequentially so that the first group is within one step of the second group in the bank. The group 1 and group 2 power circuits are installed in different cabinets, as shown in Figure 7.7-14, which also shows that one group is within one step (5/8 inch) of the other

group. A definite schedule of actuation or deactuation of the stationary gripper, moveable gripper, and lift coils of a mechanism is required to withdraw the RCCA attached to the mechanism.

Since the four stationary grippers, moveable gripper, and lift coils associated with the RCCAs of a rod group are driven in parallel, any single failure which could cause rod withdrawal would affect a minimum of one group of RCCAs. Mechanical failures are in the direction of insertion, or immobility.

Figure 7.7-15 illustrates the design features that ensure that no single electrical failure could cause the accidental withdrawal of a single RCCA from the partially inserted bank at full power operation.

Figure 7.7-15 shows the typical parallel connections on the lift, movable, and stationary coils for a group of rods. Since single failures in the stationary or movable circuits will result in dropping or preventing rod (or rods) motion, the discussion of single failure will be addressed to the lift coil circuits: 1) due to the method of wiring the pulse transformers which fire the lift coil multiplex thyristors, three of the four thyristors in a rod group could remain turned off when required to fire, if for example the gate signal lead failed open at point X_1. Upon "up" demand, one rod in group 1 and four rods in group 2 would withdraw. A second failure at point X_2 in the group 2 circuit is required to withdraw one RCCA; 2) timing circuit failures will affect the four mechanisms of a group or the eight mechanisms of the bank and will not cause a single rod withdrawal; and 3) more than two simultaneous component failures are required (other than the open wire failures) to allow withdrawal of a single rod.

The identified multiple failure involving the least number of components consists of open circuit failure of the proper two out of 16 wires connected to the gate of the lift coil thyristors. The probability of open wire (or terminal) failure is 0.016×10^{-6} per hour by MIL-HDB-217A. These wire failures would have to be accompanied by failure, or disregard, of the indications mentioned above. The probability of this occurrence is, therefore, too low to have any significance.

Concerning the human element, to erroneously withdraw a single RCCA, the operator would have to improperly set the bank selector switch, the lift coil disconnect switches, and the in-hold-out switch. In addition, the three indications would have to be disregarded or ineffective. Such series of errors would require a complete lack of understanding and administrative control. A probability cannot be assigned to a series of errors such as these.

The rod position indication system provides direct visual displays of each control rod assembly position. The plant computer alarms for deviation of rods from their banks. In addition, a rod insertion limit monitor provides an audible and visual alarm to warn the operator of an approach to an abnormal condition due to dilution. The low-low insertion limit alarm alerts the operator to follow emergency boration procedures. The facility

reactivity control systems are such that fuel damage limits will not be exceeded even in the event of a single malfunction of either system.

An important feature of the control rod system is that insertion is provided by gravity fall of the rods.

In all analyses involving reactor trip, the single, highest worth RCCA is postulated to remain untripped in its full out position.

One means of detecting a stuck control rod assembly is available from the actual rod position information displayed on the control board. The control board position readouts, one for each rod, give the plant operator the actual position of the rod in steps. The indications are grouped by banks (e.g., control bank A, control bank B, etc.) to indicate to the operator the deviation of one rod with respect to other rods in a bank. This serves as a means to identify rod deviation.

The plant computer monitors the actual position of all rods. Should a rod be misaligned from the other rods in that bank by more than 12 steps, the rod deviation alarm is actuated. Misaligned RCCAs are also detected and alarmed in the control room via the flux tilt monitoring system, which is independent of the plant computer.

Isolated signals derived from the nuclear instrumentation system are compared with one another to determine if a preset amount of deviation of average power level has occurred. Should such a deviation occur, the comparator output will operate a bistable unit to actuate a control board annunciator. This alarm will alert the operator to a power imbalance caused by a misaligned rod. By use of individual rod position readouts, the operator can determine the deviating control rod and take corrective action. The design of the plant control systems meets the requirements of GDC-23.

Refer to Section 4.3 for additional information on response considerations due to reactivity.

7.7.2.3 Step Load Changes Without Steam Dump

The plant control system restores equilibrium conditions, without a trip, following a 10-percent step reduction in load demand, over the entire power range for automatic control. Steam dump is blocked for load decrease less than or equal to 10 percent. A load demand greater than full power is prohibited by the turbine control load limit devices.

The plant control system minimizes the reactor coolant average temperature deviation during the transient within a given value and is capable of allowing manual restoration of average temperature to the programmed setpoint. Excessive pressurizer pressure variations are prevented by using spray and heaters and power relief valves in the pressurizer.

The control system must limit nuclear power overshoot to acceptable values, following a 10-percent increase in load to 100 percent. Since automatic rod withdrawal is not available at Callaway, any overshoot by the automatic rod control system is not possible.

7.7.2.4 Loading and Unloading

Ramp unloading of 5 percent per minute can be accepted over the entire power range under automatic control without tripping the plant. The function of the control system is to maintain the coolant average temperature as a function of turbine-generator load.

The coolant average temperature increases during loading and causes a continuous insurge to the pressurizer as a result of coolant expansion. The sprays limit the resulting pressure increase. Conversely, as the coolant average temperature is decreasing during unloading, there is a continuous outsurge from the pressurizer resulting from coolant contraction. The pressurizer heaters limit the resulting system pressure decrease. The pressurizer water level is programmed such that the water level is above the setpoint for heater cut out during the loading and unloading transients. The primary concern during loading is to limit the overshoot in nuclear power and to provide sufficient margin in the overtemperature ΔT setpoint.

The automatic load controls are designed to adjust the unit generation to match load requirements within the limits of the unit capability and licensed rating.

During rapid loading transients, a drop in reactor coolant temperature is sometimes used to increase core power. This mode of operation is applied when the control rods are not inserted deep enough into the core to supply all the reactivity requirements of the rapid load increase (the boron control system is relatively ineffective for rapid power changes). The reduction in temperature is initiated by continued turbine loading past the point where the control rods are completely withdrawn from the core. The temperature drop is recovered and nominal conditions restored by a boron dilution operation.

The core axial power distribution is controlled during the reduced temperature return to power by placing the control rods in the manual mode when the $\Delta\phi$ operating limits are approached. Placing the rods in manual will stop further changes in $\Delta\phi$, and it will also initiate the required drop in coolant temperature. Normally, power distribution control is not required during a rapid power increase, and the rods will be manually positioned to the top of the core. The bite position is reestablished at the end of the transient by decreasing the coolant boron concentration.

7.7.2.5 Load Rejection Furnished By Steam Dump System

When a load rejection occurs, if the difference between the required temperature setpoint of the RCS and the actual average temperature exceeds a predetermined amount, a signal will actuate the steam dump to maintain the RCS temperature within control range until a new equilibrium condition is reached.

The reactor power is reduced at a rate consistent with the capability of the rod control system. When a load rejection occurs, the rods automatically insert to reduce reactor power. The steam dump flow reduction is as fast as RCCAs are capable of inserting negative reactivity.

The rod control system can then reduce the reactor temperature to a new equilibrium value without causing overtemperature and/or overpressure conditions. The nominal steam dump steam flow capacity to the condenser is 40 percent of full load steam flow at full load steam pressure.

The steam dump flow decreases proportionally as the control rods act to reduce the average coolant temperature. The artificial load is therefore removed as the coolant average temperature is restored to its programmed equilibrium value.

The dump valves are modulated by the reactor coolant average temperature signal. The required number of steam dump valves can be tripped quickly to stroke full open or modulate, depending upon the magnitude of the temperature error signal resulting from loss of load.

7.7.2.6 Turbine-Generator Trip With Reactor Trip

Whenever the turbine-generator unit trips at an operating power level above 50-percent power, the reactor also trips. The unit is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the equivalent saturation pressure of the steam generator safety valve setpoint. The thermal capacity of the reactor coolant system is greater than that of the secondary system, and because the full load average temperature is greater than the no-load temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for a trip from full power. This heat sink is provided by the combination of controlled release of steam to the condenser and by makeup of feedwater to the steam generators.

The steam dump system is controlled from the reactor coolant average temperature signal whose setpoint values are programmed as a function of turbine load. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves.

With the dump valves open, the average coolant temperature starts to reduce quickly to the no-load setpoint. A direct feedback of temperature acts to proportionally close the valves to minimize the total amount of steam which is bypassed.

The feedwater flow is cut off following a reactor trip when the average coolant temperature decreases below a given temperature or when the steam generator water level reaches a given high level.

Additional feedwater makeup is then controlled manually to restore and maintain steam generator water level while assuring that the reactor coolant temperature is at the

desired value. Residual heat removal is maintained by the steam header pressure controller (manually selected), which controls the amount of steam flow to the condensers. This controller operates a portion of the same steam dump valves to the condensers, which are used during the initial transient following turbine and reactor trip.

The pressurizer pressure and level fall rapidly during the transient because of coolant contraction. The pressurizer water level is programmed so that the level following the turbine and reactor trip is above the heaters. However, if the heaters become uncovered following the trip, the chemical and volume control system will provide full charging flow to restore water level in the pressurizer. Heaters are then turned on to restore pressurizer pressure to normal.

The steam dump and feedwater control systems are designed to prevent the average coolant temperature from falling below the programmed no-load temperature following the trip to ensure adequate reactivity shutdown margin.

7.7.3 REFERENCES

1. Lipchak, J. B., "Nuclear Instrumentation System," WCAP-8255, January 1974. (For additional background information only.)

2. Shopsky, W. E., "Failure Mode and Effects Analysis (FMEA) of the Solid State Full Length Rod Control System," WCAP-8976, August 1977.

3. Adler, M.R., "AMSAC Generic Design Package", WCAP-10858-P-A, Revision 1, July 1987.

4. Union Electric letters on AMSAC, ULNRC-1472 dated 3-19-87, ULNRC-1492 dated 4-15-87, and ULNRC-1639 dated 10-5-87.

5. NRC Safety Evaluation Report for Union Electric Co., compliance with ATWS Rule 10CFR50.62, dated 12-24-87.

TABLE 7.7-1 PLANT CONTROL SYSTEM INTERLOCKS

Designation	Derivation	Function
C-1	1/2 neutron flux (intermediate range) above setpoint	Blocks control rod withdrawal (Note 1)
C-2	1/4 neutron flux (power range) above setpoint	Blocks control rod withdrawal (Note 1)
C-3	2/4 overtemperature ΔT above	Blocks control rod withdrawal (Note 1) Actuates turbine runback via load reference Defeats remote load dispatching (if remote load dispatching is used)
C-4	2/4 overpower ΔT above setpoint	Blocks control rod withdrawal (Note 1) Actuates turbine runback via load reference Defeats remote load dispatching (if remote load dispatching is used)
C-5	1/1 turbine impulse chamber pressure below setpoint	Defeats remote load dispatching (if remote load dispatching is used) Blocks automatic control rod withdrawal (no longer available)
C-7	1/1 time derivative (absolute value) of turbine impulse chamber pressure (decrease only) above setpoint	Makes steam dump valves available for either tripping or modulation. See Figure 7.2-1 (Sheet 10).
C-9A,B,C	Condenser pressure below setpoint	Absence blocks steam dump to condenser. See Fig. 7.2-1 (Sheet 10).

Note 1: Automatic rod withdrawal is no longer available.

TABLE 7.7-1 (Sheet 2)

Designation	Derivation	Function
C-11	1/1 bank D control rod position above setpoint	Blocks automatic control rod withdrawal (no longer available)
C-20	2/2 turbine impulse chamber pressures above 38% reactor power (1370 mwt) (See Section 7.7.1.11)	Enables AMSAC signals for: - turbine trip - AFW actuation - steam generator blowdown and sample line isolation
P-4	Reactor trip	Makes steam dump valves available for either tripping or modulation Blocks steam dump control via load rejection T_{avg} controller
	Absence of P-4 (Reactor not tripped)	Blocks steam dump control via plant trip T_{avg} controller
P-12	2/4 T_{avg} below setpoint	Blocks steam dump. Allows manual bypass of steam dump block for the three cooldown valves only.
	3/4 T_{avg} above setpoint	Defeats the manual bypass of steam dump block for the three cooldown valves.

TABLE 7.7-2 BORON CONCENTRATION MEASUREMENT SYSTEM SPECIFICATIONS

Operating Conditions

Line voltage: 120 Volt ac, ± 10 percent, 60 Hz ± 1 percent

Pressure: 15 to 225 psig (sample)

Temperature: 70 to 130°F (sample)

Sample flow rate: 0 to 0.4 gpm

Ambient temperature: 60 to 105°F

Relative humidity: to 95 percent

Radiation levels: <2 mr/hr @ 24 inches from all tank surfaces

Accuracy

Boron parts/million parts of water	Accuracy Standard Deviation
0 - 1,800 ppm	± 10 ppm
1,800 - 5,000 ppm	± 1.25 percent

Drift: less than 10 ppm/week

APPENDIX 7A - COMPARISON TO REGULATORY GUIDE 1.97, REVISION 2

7A.1 INTRODUCTION

This appendix provides an evaluation of the instrumentation to assess plant and environs conditions following an accident. The plant instrumentation and features provided in the Callaway Plant have resulted from detailed design evaluations and reviews. Design features that enable the plant to be taken to cold shutdown while utilizing only safety-grade equipment are described in Appendix 5.4A, Cold Shutdown. Chapter 18.0 provides a comparison of the Callaway design to the requirements of NUREG-0737.

Since most of the instrumentation in the Callaway Plant was purchased and installed prior to the issuance of Regulatory Guide 1.97, Revision 2, strict compliance to the many prescriptive recommendations is not provided in all cases. However, the Callaway instrumentation and control room design is adequate to allow the operators to evaluate and mitigate the consequences of postulated accidents.

This appendix provides a detailed comparison of the Callaway design to the recommendations contained in the regulatory guide.

7A.2 ORGANIZATION

The text of this appendix provides a summary description of the bases for the Callaway instrumentation design as they relate to the recommendations of the regulatory guide. The tables provide the data necessary to perform a detailed comparison of the Callaway design with the recommendations of the regulatory guide.

Table 7A-1 is a cross-reference between Table 2 of the regulatory guide and the information presented in this appendix. Table 7A-1 lists the variables in the same sequence in which they appear in the regulatory guide table, assigns variable identification numbers, and identifies the data sheet upon which the detailed comparison with the Callaway design has been provided.

Table 7A-2 provides a summary of the Callaway design to the recommendations of the regulatory guide. This table also serves as an index to the data sheets in Table 7A-3.

Table 7A-3 consists of individual data sheets. One data sheet is provided for each variable or group of related variables identified in Table 2 of the regulatory guide. The data sheet contains the recommended range, category, and purpose for the variable and includes the multiple listing requirements. A discussion is provided of the Callaway Plant design bases for ranges, qualification, etc., and other pertinent data which support the adequacy of the current design or describe design modifications which are being implemented. ERFIS (Emergency Response Facility Information System), BOP (Balance of Plant), RRIS (Radiation Release Information System), and NSSS (Nuclear

Steam Supply System) are applications of the Plant Computer. Table 7A-3 provides the name of the Plant Computer application to which the variable is inputted.

7A.3 CALLAWAY DESIGN BASIS COMPARISON TO REGULATORY GUIDE 1.97

The Callaway design bases are stated throughout the FSAR. The discussions provided below summarize the Callaway design bases as they pertain to the salient recommendations of the regulatory guide. Appropriate references to other FSAR sections are provided in Table 7A-3 for more detailed information. The discussions below are intended to aid the review of the Callaway design bases for compliance with the intent of the regulatory guide recommendations.

7A.3.1 TYPE A VARIABLES

Variables classified as Type A for the Callaway design are identified in Table 7A-2. The reason for the classification is provided on the corresponding data sheet in Table 7A-3.

The following criteria are the bases for identification of Type A variables for the Callaway Plant. The terminology used in the discussion is consistent with that of the generic Emergency Response Guidelines (ERGs) for Westinghouse plants, which were submitted to the NRC by Westinghouse Owners Group letter OG-64, dated November 30, 1981.

a. Variables used for event diagnosis are classified as Type A because these variables direct the operator to the appropriate Optimal Recovery Guidelines (formerly termed Emergency Operating Instructions) or to monitoring of critical Safety Functions.

b. Variables used by the operator to perform manual actions prescribed by the Optimal Recovery Guidelines, which are associated with Condition IV events (LOCA, MSLB, and SGTR), are classified as Type A. Condition I, II and III events are not considered in identifying Type A variables (e.g., Spurious Safety Injection).

c. Variables which identify the need for operator action to correct single failures are not classified as Type A. These actions are often identified as "Notes" or "Contingency Actions" in the ERGs.

d. Variables associated with operator actions required for events not currently in the design bases of the plant are not identified as Type A variables.

7A.3.2 REDUNDANCY AND DIVERSITY FOR CATEGORY 1 VARIABLES

The following discussion summarizes salient points of the design with respect to the regulatory recommendations:

a. Adequate redundancy is considered to exist when adequate information is available to the operator to make appropriate decisions, assuming a single failure. This is done on a system, loop, or component basis, as appropriate. For the steam generator heat sink function and pressurizer, it was done on a component basis. For the reactor and reactor coolant loops, it was done on a system basis due to the abundance of diverse or associated variables which are available to indicate the nature of the event and identify its cause.

b. Diverse variables are considered to be those which vary directly with or have a direct relation with the primary variable. Associated variables are those which, when considered with the primary and/or diverse variables, aid in the identification and evaluation of events and the status of the plant.

c. The need for a third reading or a diverse variable is based on the control room operators' need for the identification of the proper recovery from an event. Diversity is not provided solely for TSC/EOF use, accident reconstruction, or range not associated with DBEs.

d. Since the need for a diverse variable arises upon the single failure of the primary instrumentation and that failure must result in ambiguity (e.g., the instrument fails in midscale, not offscale high or low), diverse variables may be performance or commercial grade. Many diverse variables are qualified as Class 1E for reasons other than their diversity function.

e. Items identified as diverse variables are not considered to be part of the post-accident monitoring data base and are not included in the Emergency Response Facility Data Base solely for that purpose. Many diverse variables are part of the post-accident monitoring data base because of their primary function. Since it is highly unlikely that a variable will be required for a diversity function, the EOF/TSC may contact the control room should the need arise.

f. There are no unique PAMS identifiers on the control panels. Emergency operating procedures provide sufficient direction to post-accident monitors that should be used. Regulatory Position C.1.4 was deleted in Revision 3 of Regulatory Guide 1.97.

7A.3.3 RECORDERS

Dedicated recorders are required only where trend information is immediately required for operator use. The current value (indicated) of the PAMs variables is normally used by the operator for decision-making purposes. Where Class 1E indicators are provided for safety-related Category 1 and Category 2 parameters at Callaway, as discussed in Section 7A.3.7 and justified in the individual data sheets of Table 7A-3, recorders may be performance grade.

7A.3.4 INSTRUMENT RANGES

Instrument ranges have been determined, considering the function(s) of the sensed parameters. The installed instrumentation may meet the ranges recommended in the regulatory guide, meet the intent of the recommended range, or have a range appropriate for the design function. Instrumentation that has an appropriate range is identified on Table 7A-2. The ranges are justified on the individual data sheets of Table 7A-3.

7A.3.5 UNNECESSARY VARIABLES

Several variables listed in the regulatory guide are not necessary for post-accident monitoring for the Callaway Plant. Table 7A-2 identifies which variables are considered unnecessary from a post-accident monitoring standpoint, and the individual data sheets provide a discussion justifying the determination.

7A.3.6 QUALIFICATION FOR CATEGORY 1 PARAMETERS

Tables 7A-2 and 7A-3 show that instrumentation for all variables designated as Category 1 by the NRC and those designated as Type A herein are qualified as Class 1E from the sensor to the indicator.

Qualification of these devices was documented in the SNUPPS NUREG-0588 submittal which was provided to the NRC in March 1983. All Class 1E equipment is qualified in accordance with Regulatory Guide 1.89, and Regulatory Guide 1.100 as discussed in Appendix 3A.

7A.3.7 QUALIFICATION FOR CATEGORY 2 PARAMETERS

The Callaway design utilizes Class 1E and non-Class 1E sensors, transmitters, indicators, and power sources. There is no qualification category between these two categories, as implied by the Category 2 terminology of the regulatory guide.

Table 7A-2 shows that many of the Category 2 items are in fact fully qualified to Class 1E environmental and seismic requirements. These items exceed the regulatory recommendations.

The non-Class 1E instruments are termed performance grade. These items are purchased to perform in their anticipated service environments for the plant conditions in which they must function. The regulatory guide implies that they must function in the accident environment for the area in which they are located without consideration of the design function. If an instrument has to function following an accident, it is fully qualified to Class 1E requirements. If the instrument is not required following an accident, it is termed non-safety-related and purchased to performance grade requirements. The equipment service conditions are provided in the purchase specification and include radiation levels and integrated doses, temperature, relative humidity, and other special

considerations. The current qualification levels for each item reflect its importance to safety. Table 7A-3 addresses the function of performance grade items in Category 2.

Non-Class 1E equipment is supplied from Separation Groups 5 and 6, which are highly reliable (refer to Section 8.3.1.3). The non-Class 1E 125 V dc buses are backed by the emergency diesel generators.

For the purpose of compliance to the regulatory requirements for seismic qualification for items identified as Category 2, the sensors/transmitters continued operation is not assumed to be required, since the indicators need not be qualified. Assurance of pressure boundary integrity during and after seismic events is ensured for safety-related systems. No seismic requirements are placed on items in non-safety-related systems.

7A.3.8 QUALIFICATION FOR CATEGORY 3 ITEMS

The Category 3 qualification guidelines of the regulatory guide imply a possible need to ensure that the instrument sensor and transmitter are qualified for an accident environment. Table 7A-2 identifies those Category 3 instruments located inside the containment, and the appropriate data sheet of Table 7A-3 justifies the lack of post-accident qualification.

TABLE 7A-1 REGULATORY GUIDE 1.97 VARIABLE LIST

VARIABLE IDENT. NO.	VARIABLE	DATA SUMMARY SHEET NO.
B.1	Reactivity Control	
B.1.1	Neutron Flux	1.1
B.1.2	Control Rod Position	1.2
B.1.3	RCS Soluble Boron Concentration	13.1
B.1.4	RCS Cold Leg Water Temperature	2.1
B.2	Core Cooling	
B.2.1	RCS Hot Leg Water Temperature	2.2
B.2.2	RCS Cold Leg Water Temperature	2.1
B.2.3	RCS Pressure	2.3
B.2.4	Core Exit Temperature	1.3
B.2.5	Coolant Level in Reactor	1.4
B.2.6	Degrees of Subcooling	1.5
B.3	Maintaining Reactor Coolant System Integrity	
B.3.1	RCS Pressure	2.3
B.3.2	Containment Sump Water Level	6.2
B.3.3	Containment Pressure	6.1
B.4	Maintaining Containment Integrity	
B.4.1	Containment Isolation Valve Position (excluding check valves)	6.3
B.4.2	Containment Pressure	6.1
C.1	Fuel Cladding	
C.1.1	Core Exit Temperature	1.3
C.1.2	Radioactivity Concentration or Radiation Level in Circulating Primary Coolant	13.3

TABLE 7A-1 (Sheet 2)

VARIABLE IDENT. NO.	VARIABLE	DATA SUMMARY SHEET NO.
C.1.3	Analysis of Primary Coolant (gamma spectrum)	13.1
C.2	Reactor Coolant Pressure Boundary	
C.2.1	RCS Pressure	2.3
C.2.2	Containment Pressure	6.1
C.2.3	Containment Sump Water Level	6.2
C.2.4	Containment Area Radiation	11.1
C.2.5	Effluent Radioactivity - Noble Gas Effluent from Condenser Air Removal System Exhaust	12.2
C.3	Containment	
C.3.1	RCS Pressure	2.3
C.3.2	Containment Hydrogen Concentration	6.4
C.3.3	Containment Pressure	6.1
C.3.4	Containment Effluent Radioactivity - Noble Gases from Identified Release Points	12.1
C.3.5	Radiation Exposure Rate (inside building or areas, e.g., auxiliary building, reactor shield building annulus, and fuel handling building, which are in direct contact with primary containment where penetrations and hatches are located)	11.2
C.3.6	Effluent Radioactivity - Noble Gases (from buildings as indicated above)	12.1
D.1	Residual Heat Removal (RHR) or Decay Heat Removal System	
D.1.1	RHR System Flow	3.1
D.1.2	RHR Heat Exchanger Outlet Temperature	3.1
D.2	Safety Injection Systems	
D.2.1	Accumulator Tank Level and Pressure	3.2
D.2.2	Accumulator Isolation Valve Position	3.2

TABLE 7A-1 (Sheet 3)

VARIABLE IDENT. NO.	VARIABLE	DATA SUMMARY SHEET NO.
D.2.3	Boric Acid Charging Flow	3.3
D.2.4	Flow in HPI System	3.3
D.2.5	Flow in LPI System	3.1
D.2.6	Refueling Water Storage Tank Level	3.4
D.3	Primary Coolant System	
D.3.1	Reactor Coolant Pump Status	2.4
D.3.2	Primary System Safety Relief Valve Positions (including PORV and code valves) or Flow Through or Pressure in Relief Valve Lines	2.5
D.3.3	Pressurizer Level	2.6
D.3.4	Pressurizer Heater Status	2.7
D.3.5	Quench Tank Level	2.8
D.3.6	Quench Tank Temperature	2.8
D.3.7	Quench Tank Pressure	2.8
D.4	Secondary System (Steam Generator)	
D.4.1	Steam Generator Level	4.1
D.4.2	Steam Generator Pressure	4.2
D.4.3	Safety/Relief Valve Positions or Main Steam Flow	4.3
D.4.4	Main Feedwater Flow	4.4
D.5	Auxiliary Feedwater or Emergency Feedwater System	
D.5.1	Auxiliary or Emergency Feedwater Flow	5.1
D.5.2	Condensate Storage Tank Water Level	5.2
D.6	Containment Cooling Systems	
D.6.1	Containment Spray Flow	10.1

TABLE 7A-1 (Sheet 4)

VARIABLE IDENT. NO.	VARIABLE	DATA SUMMARY SHEET NO.
D.6.2	Heat Removal by the Containment Fan Heat Removal System	8.1
D.6.3	Containment Atmosphere Temperature	6.5
D.6.4	Containment Sump Water Temperature	6.6
D.7	Chemical and Volume Control System	
D.7.1	Makeup Flow-In	7.1
D.7.2	Letdown Flow-Out	7.1
D.7.3	Volume Control Tank Level	7.1
D.8	Cooling Water System	
D.8.1	Component Cooling Water Temperature to ESF System	9.1
D.8.2	Component Cooling Water Flow to ESF System	9.1
D.9	Radwaste System	
D.9.1	High-Level Radioactive Liquid Tank Level	14.1
D.9.2	Radioactive Gas Holdup Tank Pressure	14.2
D.10	Ventilation Systems	
D.10.1	Emergency Ventilation Damper Position	15.1
D.11	Power Supplies	
D.11.1	Status of Standby Power and Other Energy Sources Important to Safety (hydraulic, pneumatic)	16.1, 16.2
E.1	Containment Radiation	
E.1.1	Containment Area Radiation - High Range	11.1
E.2	Area Radiation	
E.2.1	Radiation Exposure Rate (inside buildings or areas where access is required to service equipment important to safety)	11.2

TABLE 7A-1 (Sheet 5)

VARIABLE IDENT. NO.	VARIABLE	DATA SUMMARY SHEET NO.
E.3	Airborne Radioactive Materials Released from Plant	
E.3.1	Noble Gases and Vent Flow Rate	
E.3.1.1	o Containment or Purge Effluent	12.1
E.3.1.2	o Reactor Shield Building Annulus (if in design)	NA
E.3.1.3	o Auxiliary Building (including any building containing primary system gases, e.g., waste gas decay tank)	12.1
E.3.1.4	o Condenser Air Removal System Exhaust	12.2
E.3.1.5	o Common Plant Vent or Multipurpose Vent Discharging Any of Above Releases (if containment purge is included)	12.1
E.3.1.6	o Vent From Steam Generator Safety Relief Valves or Atmospheric Dump Valves	12.3
E.3.1.7	o All Other Identified Release Points	12.4
E.3.2	Particulates and Halogens	
E.3.2.1	o All Identified Plant Release Points (except steam generator safety relief valves or atmospheric steam dump valves and condenser air removal system exhaust). Sampling with Onsite Analysis Capability	12.5
E.4	Environs Radiation and Radioactivity	
E.4.1	Radiation Exposure Meters (continuous indication at fixed locations)	17.1
E.4.2	Airborne Radiohalogens and Particulates (portable sampling with onsite analysis capability)	17.2
E.4.3	Plant and Environs Radiation (portable instrumentation)	17.3
E.4.4	Plant and Environs Radioactivity (portable instrumentation)	17.4
E.5	Meteorology	
E.5.1	Wind Direction	17.5

TABLE 7A-1 (Sheet 6)

VARIABLE IDENT. NO.	VARIABLE	DATA SUMMARY SHEET NO.
E.5.2	Wind Speed	17.5
E.5.3	Estimation of Atmospheric Stability	17.5
E.6	Accident Sampling Capability (Analysis Capability on Site)	
E.6.1	Primary Coolant	13.1
E.6.1.1	o Gross Activity	13.1
E.6.1.2	o Gamma Spectrum	13.1
E.6.1.3	o Boron Content	13.1
E.6.1.4	o Chloride Content	13.1
E.6.1.5	o Dissolved Hydrogen or Total Gas	13.1
E.6.1.6	o Dissolved Oxygen	13.1
E.6.1.7	o pH	13.1
E.6.2	Sump	13.2
E.6.2.1	o Gross Activity	13.2
E.6.2.2	o Gamma Spectrum	13.2
E.6.2.3	o Boron Content	13.2
E.6.2.4	o Chloride Content	13.2
E.6.2.5	o pH	13.2
E.6.3	Containment Air	
E.6.3.1	o Hydrogen Content	6.4
E.6.3.2	o Oxygen Content	13.1
E.6.3.3	o Gamma Spectrum	13.1

TABLE 7A-2 SUMMARY COMPARISON TO REGULATORY GUIDE 1.97

DATA SHEET NUMBER	VARIABLE DESCRIPTION	NRC QUAL. CATEGORY	CALLAWAY TYPE A VARIABLE	RANGE COMPARISON: Complies with Reg.	RANGE COMPARISON: Meets Intent	RANGE COMPARISON: Appropriate Range	SENSOR LOCATION: Inside Ctmt	SENSOR LOCATION: Outside Ctmt	CHANNEL QUALIFICATION: Class 1E	CHANNEL QUALIFICATION: Perf. Grade
CORE AND REACTOR VESSEL VARIABLES										
1.1	Neutron Flux	1		X			X		X	
1.2	Control Rod Position	3		X			X			X
1.3	Core Exit Temperature	1		X			X		X	
1.4	Reactor Vessel Level	1		X			X		X*	
1.5	Subcooling Monitor	2**		X			X		X	
RCS AND RELATED VARIABLES										
2.1	RCS T_{cold}	1	Yes	X***			X		X*	
2.2	RCS T_{hot}	1	Yes	X***			X		X*	
2.3	RCS Pressure	1	Yes	X			X		X*	
2.4	RCP Status (motor current)	3		X				X		X
2.5	Primary System Safety Relief Valve Position	2		X			X		X	
2.6	Pressurizer Level	1	Yes		X		X		X*	
2.7	Pressurizer Heater Status	2		X				X	X	
2.8	PRT Level	3		X			X			X
2.8	PRT Temperature	3				X	X			X
2.8	PRT Pressure	3		X			X			X
ECCS VARIABLES										
3.1	RHR/LPI Flow Rate	2		X				X		X
3.1	RHR/Heat Exchanger T_{out}	2				X		X		X
3.2	Accumulator Tank Level	2		NA****			X			X
3.2	Accumulator Tank Pressure	2		NA****			X			X

TABLE 7A-2 (Sheet 2)

DATA SHEET NUMBER	VARIABLE DESCRIPTION	NRC QUAL. CATEGORY	CALLAWAY TYPE A VARIABLE	RANGE COMPARISON: Complies with Reg.	RANGE COMPARISON: Meets Intent	RANGE COMPARISON: Appropriate Range	SENSOR LOCATION: Inside Ctmt	SENSOR LOCATION: Outside Ctmt	CHANNEL QUALIFICATION: Class 1E	CHANNEL QUALIFICATION: Perf. Grade
3.2	Accumulator Isolation Valve Position	2		X			X		X	
3.3	ECCS Centrifugal Charging Pump Flow	2		X				X	X	
3.3	Safety Injection Pump Flow	2		X				X		X
3.3	RCP Seal Injection Flow	2		X				X	X	
3.4	RWST Level	2	Yes	X				X	X*	
SECONDARY SIDE VARIABLES										
4.1	Steam Generator Level - Wide Range	1			X		X		X*	
4.1	Steam Generator Level - Narrow Range	1	Yes	NA			X		X	
4.2	Steam Line Pressure	1	Yes		X			X	X*	
4.3	Secondary Side PORV Position	2		X				X	X	
4.3	Secondary Side Safety Valve Position	2		NA			NA		NA	
4.4	Main Feedwater Flow Rate	3		X				X		X
AUXILIARY FEEDWATER SYSTEM VARIABLES										
5.1	Auxiliary Feedwater Flow Rate	2		X				X	X	
5.2	Condensate Storage Tank Level (Pressure)	1		X				X	X	
CONTAINMENT VARIABLES										
6.1	Containment Pressure - Design Pressure Range	1	Yes	X			X		X*	
6.1	Containment Pressure - Extended Range	1		X			X		X*	

TABLE 7A-2 (Sheet 3)

DATA SHEET NUMBER	VARIABLE DESCRIPTION	NRC QUAL. CATEGORY	CALLAWAY TYPE A VARIABLE	RANGE COMPARISON: Complies with Reg.	RANGE COMPARISON: Meets Intent	RANGE COMPARISON: Appropriate Range	SENSOR LOCATION: Inside Ctmt	SENSOR LOCATION: Outside Ctmt	CHANNEL QUALIFICATION: Class 1E	CHANNEL QUALIFICATION: Perf. Grade
6.2	Containment Normal Sump Level	1	Yes	X			X		X	
6.2	Containment Recirculation Sump Level	1		X			X		X	
6.3	Containment Isolation Valve Position	1		X			X	X	X	
6.4	Containment Hydrogen Concentration	3		X			X		X	
6.5	Containment Atmosphere Temperature	2		X			X		X	
6.6	Containment Sump Temperature	2		NA****						
CHARGING AND LETDOWN SYSTEM VARIABLES										
7.1	Normal Charging Flow	2			X			X		X
7.1	Normal Letdown Flow	2		X				X		X
7.1	Volume Control Tank Level	2			X			X	X	
7.1	Letdown Flow - Safety Related	2		X			X		X	
CONTAINMENT COOLING SYSTEM VARIABLES										
8.1	Containment Cooler Heat Removal	2		NA****						
COMPONENT COOLING WATER SYSTEM VARIABLES										
9.1	Component Cooling Water Temperature to ESF	2		X				X	X	
9.1	Component Cooling Water Flow Rate to ESF	2		X				X		X
CONTAINMENT SPRAY SYSTEM VARIABLES										
10.1	Containment Spray Flow Rate	2			X			X		X

TABLE 7A-2 (Sheet 4)

DATA SHEET NUMBER	VARIABLE DESCRIPTION	NRC QUAL. CATEGORY	CALLAWAY TYPE A VARIABLE	RANGE COMPARISON: Complies with Reg.	RANGE COMPARISON: Meets Intent	RANGE COMPARISON: Appropriate Range	SENSOR LOCATION: Inside Ctmt	SENSOR LOCATION: Outside Ctmt	CHANNEL QUALIFICATION: Class 1E	CHANNEL QUALIFICATION: Perf. Grade
AREA RADIATION MONITORING 1										
11.1	Containment Area Radiation	1	Yes	X			X		X	
11.2	Area Radiation Monitor - Containment Penetrations Hatches and Areas Important to Safety	2		N/A****						
EFFLUENT MONITORS										
12.1	Unit Vent and Radwaste Building Vent - Noble Gas	2		X				X		X
12.2	Condensate Air Removal - Radiation Monitor	3		X				X		X
12.3	Secondary Side Radiation Release	2			X			X		X
12.4	AFW Turbine Radiation Release	2			X			X		X
12.5	Unit Vent and Radwaste Building Vent Particulates and Halogens	3		X				X		X
SAMPLING SYSTEMS										
13.1	Post-Accident Sampling System	3		NA****				X		X
13.2	Containment Recirculation Sump Sample	3		NA****				X		X
13.2	ECCS Room Sump Sample	3		NA****						
13.2	Auxiliary Building Sump Sample	3		NA****						
13.3	Radiation Level in RCS	1		NA****						
RADWASTE SYSTEM VARIABLES										
14.1	Recycle Holdup Tank Level	3		NA****						
14.2	Waste Gas Decay Tank Pressure	3		NA****						

TABLE 7A-2 (Sheet 5)

DATA SHEET NUMBER	VARIABLE DESCRIPTION	NRC QUAL. CATEGORY	CALLAWAY TYPE A VARIABLE	RANGE COMPARISON: Complies with Reg.	RANGE COMPARISON: Meets Intent	RANGE COMPARISON: Appropriate Range	SENSOR LOCATION: Inside Ctmt	SENSOR LOCATION: Outside Ctmt	CHANNEL QUALIFICATION: Class 1E	CHANNEL QUALIFICATION: Perf. Grade
DAMPER POSITION										
15.1	Emergency Ventilation Damper Position	2		X			X	X	X	
POWER SUPPLY STATUS INDICATION										
16.1	Electric Power Supply Status	2		X				X	X	
16.2	Gas Accumulator Tank Pressure	2		X				X		X
ENVIRONMENTAL MONITORING										
17.1	Fixed Radiation Exposure Meters	3		NA****						
17.2	Portable Emergency Monitor - Particulates and Halogen	3		X				X		X
17.3	Particulates Monitor - Plant and Environs	3		X				X		X
17.4	Plant and Environs - Gamma Spectra	3		X				X		X
17.5	Meteorological Parameters	3		X				X		X

* Recorder is non-1E

** Qualified to Category 1 requirements for RCS T_{cold} and T_{hot} indication.

*** Complies with range recommended in Revision 3 of Regulatory Guide 1.97.

**** Unnecessary variables - refer to Table 7A-3

TABLE 7A-3

DATA SHEET 1.1

I. <u>REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS</u>

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.1.1	Neutron Flux	10^{-6}% to 100% full power	1	Function detection, accomplishment of mitigation

II. <u>CALLAWAY PLANT DESIGN PROVISIONS</u>

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.1.1	Neutron Flux	10^{-8} to 200% power	SENE60	Y	020	Y	-	-	BOP
			SENE61	Y			020	Y	BOP

III. <u>REMARKS</u>

1. Redundant Class 1E neutron flux monitors, independent from the NSSS protection system, have been added to the Callaway design. These monitors meet the stated recommendations. Section 6.2.2 of ANSI/ANS-4.5-1980 recommends that current value, rate, and trend information be available to the control room operators. The instrumentation identified above provides for current value and trend information (i.e. indication and recording). The Westinghouse NIS equipment provides for current value, rate, and trend information; however, the NIS instrumentation is not qualified for post-accident conditions.

TABLE 7A-3 (Sheet 2)

DATA SHEET 1.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.1.2	Control Rod Position	Full in or not full in	3	Verification

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.1.2	Control Rod Position	Full in to full out	SF0074 53 rods	N	022	N			NSSS

III. REMARKS

1. The Callaway design meets the stated recommendations.

2. Callaway has 53 full-length control rods arranged in four control banks (A through D) and five shutdown banks (SA-SE). With the exception of shutdown banks SC, SD, and SE, each bank is divided into two groups. Each group consists of several assemblies which move together.

3. The rod position monitoring is performed by two separate systems: (1) the digital rod position indication system and (2) a demand position system. The position of each rod is indicated on a dedicated LED. These systems are described in FSAR Section 7.7.1.3.2.

TABLE 7A-3 (Sheet 3)

DATA SHEET 1.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.2.4	Core Exit Temperature[1]	200°F to 2300°F (for operating plants -200°F to 1650°F)	3[3]	Verification
C.1.1	Core Exit Temperature[1]	200°F to 2300°F (for operating plants -200°F to 1650°F)	1[3]	Detection of potential for breach, accomplishment of mitigation, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.2.4 C.1.1	Core Exit Temperature	0-2500°F	TC0001 through TC0050 minus CETs retired in place or removed from service)	Y	RP081A,B	Y	RP081A,B	Y	NSSS

III. REMARKS

1. The Callaway design meets the stated recommendations.

2. All 50 thermocouples were originally qualified to Class 1E requirements and provide inputs to the subcooling monitor described on data sheet 1.5. Subcooling monitor display output scale includes 200°F subcooled to 2000°F superheated range.

3. All 50 thermocouples (minus those retired in place or removed from service) are indicated and recorded on qualified devices in the control room. Diversity is not required due to extensive redundancy provided.

TABLE 7A-3 (Sheet 4)

DATA SHEET 1.4

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.2.5	Coolant Level in Reactor	Bottom of core to Top of Vessel (direct indicating or recording device not required	1	Verification, accomplishment of mitigation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.2.5	Reactor Vessel Water Level	Bottom to top of vessel	LT 1311	Y	021	Y	080	N	NSSS
			LT 1312	Y	021	Y	080	N	NSSS
			LT 1321	Y	021	Y	-	-	NSSS
			LT1322	Y	021	Y	-	-	NSSS

III. REMARKS

1. The Callaway design meets all of the stated recommendations.

2. The Callaway RV level indication system will provide information on the RV water level with or without the RC pumps in operation. This Class 1E system will utilize two pressure taps to cover the range from the bottom of the vessel to the top of the vessel.

3. The design includes four indicating devices which provide redundancy (two devices) for the two design conditions.

4. Diversity is provided by the core exit thermocouples described on data sheet 1.3.

TABLE 7A-3 (Sheet 5)

DATA SHEET 1.5

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.2.6	Degrees of Subcooling to 35°F superheat	200°F subcooling (With confirmatory operator procedures)	2	Verification, and analysis of plant conditions

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.2.6	Subcooling Monitor	200°F subcooled to 2,000°F	PT0403, PT0405 (1 of 2)	Y	022 (TI1390A,B) RP081A,B (UU/390A,B)	Y	RP081A,B (TR1390A,B)	Y	NSSS
		superheat	PT0455, PT0456 PT0457, PT0458 (2 of 4) TE0413A,B TE0423A,B TE0433A,B	Y			-	-	NSSS
			TE0443A,B TC001 through	Y					
			TC0050 (minus CETs retired in place or removed from service)	Y					

III. REMARKS

1. The Callaway subcooling monitor meets all of the stated recommendations.

2. The subcooling monitor design provisions are described in Section 18.2.13.2. The system is Class 1E and fully qualified.

3. Diversity is not required, since this system is considered to be Category 2 per the regulatory recommendations; however, extensive redundancy in the inputs is provided to ensure system reliability.

4. This system could be utilized by the plant operators following an event; however, it is not considered a Type A variable, since the operator will be able to perform subcooling calculations, using existing instrumentation.

TABLE 7A-3 (Sheet 6)

DATA SHEET 2.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.1.4	RCS Cold Leg Water Temperature[1]	50°F to 400°F	3	Verification
B.2.2	RCS Cold Leg Water Temperature[1]	50°F to 750°F*	1	Function detection, accomplishment of mitigation, verification, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.1.4	RCS Temperature	0-700°F	TE-413B	Y	021	Y	022	N	NSSS
B.2.2	Wide Range	0-700°F	TE-423B	Y	021	Y	022	N	NSSS
	T_{cold}	0-700°F	TE-433B	Y	-	-	022	N	NSSS
		0-700°F	TE-443B	Y	-	-	022	N	NSSS

III. REMARKS

1. The RCS wide-range T_{cold} instruments are Class **1**E and powered from Protection Sets I and II. Protection Set I instruments are indicated separately on a qualified indicator. The T_{cold} and T_{hot} readings for each loop are recorded on a dual pen recorder. All RCS T_{hot} and T_{cold} wide-range instrument readings are available on qualified indicators in the Core Sub-cooling Monitors (RP081A&B).

2. The existing range meets the recommended range of Revision 3 of Regulatory Guide 1.97. Other associated variables will be available to help ensure that the operator is aware of primary system parameters.

3. Diversity is not required due to the extensive redundancy provided; however, the operator can use the steam line pressure of the associated steam generator to estimate the T_{cold} readings. T_{cold} will trend with T_{sat} for each steam generator. Associated variables which provide useful information include T_{hot} and the core exit temperatures.

4. This parameter is a Type A variable, and it is used throughout the EOIs.

*Revision 3 of Regulatory Guide 1.97 revised the range to 50°F to 700°F. Thus, the existing range now meets the regulatory recommendation.

TABLE 7A-3 (Sheet 7)

DATA SHEET 2.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.2.1	RCS Hot Leg Water Temperature 1	50°F to 750°F	1	Function detection, accomplishment of mitigation, verification, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.2.1	RCS	0-700°F	TE-413A	Y	021	Y	022	N	NSSS
	Temperature	0-700°F	TE-423A	Y	021	Y	022	N	NSSS
	Wide								
	Range T_{Hot}	0-700°F	TE-433A	Y	-	-	022	N	NSSS
		0-700°F	TE-443A	Y	-	-	022	N	NSSS

III. REMARKS

1. The RCS wide-range T_{hot} instruments are Class 1E and powered from Protection Sets I and II. Protection Set I instruments are indicated separately on a qualified indicator. As noted on data sheet 2.1, T_{hot} is recorded with T_{cold} of the same loop on a dual pen recorder. All RCS T_{hot} and T_{cold} wide-range instrument readings are available on qualified indicators in the Core Sub-cooling Monitors (RP081A&B).

2. The existing range meets the recommended range of Revision 3 of Regulatory Guide 1.97.

3. Diversity is not required due to the extensive redundancy provided; however, the operator could use the core exit thermocouples as a diverse measurement. Refer to data sheet 1.3.

4. This parameter is a Type A variable, and it is used throughout the EOIs.

TABLE 7A-3 (Sheet 8)

DATA SHEET 2.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.2.3	RCS Pressure[1]	0-3000 psig (4,000 psig for CE plants)	1[2]	Function detection, accomplishment of mitigation, verification, long-term surveillance
B.3.1	RCS Pressure[1]	0-3000 psig (4,000 psig for CE plants)	1[2]	Function detection, accomplishment of mitigation
C.2.1	RCS Pressure[1]	0-3000 psig (4,000 psig for CE plants)	1[2]	Detection of potential or actual breach, accomplishment of mitigation, long-term surveillance
C.3.1	RCS Pressure[1]	0-3000 psig (4,000 psig for CE plants)	1[2]	Detection of potential for breach, accomplishment of mitigation.

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.2.3	RCS Pressure	0-3,000 psig	PT-405	Y	022	Y	022	N	NSSS
B.3.1		0-3,000 psig	PT-403	Y	022	Y	022	N	NSSS
C.2.1		0-3,000 psig	PT-406	Y	002	Y	-	-	-
NA	Pressurizer Pressure	1,700 to 2,500 psig	PT-455	Y	002	N	022	N	NSSS
			PT-456	Y	002	N	PR 455 - Select 1 of 4		NSSS
			PT-457	Y	002	N			NSSS
			PT-458	Y	002	N			NSSS

III. REMARKS

1. The RCS pressure instruments meet all of the stated requirements.

2. RCS pressure is a Type A variable, and is used throughout the EOIs.

TABLE 7A-3 (Sheet 9)

DATA SHEET 2.4

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.3.1	Reactor Coolant Pump Status	Motor Current	3	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.3.1	Reactor	0-600A	CT-PA0107	N	021	N	-	-	BOP
	Coolant Pump	0-600A	CT-PA0108	N	021	N	-	-	BOP
	Motor Current	0-600A	CT-PA0204	N	021	N	-	-	BOP
		0-600A	CT-PA0205	N	021	N	-	-	BOP

III. REMARKS

1. The design meets the stated recommendations.

TABLE 7A-3 (Sheet 10)

DATA SHEET 2.5

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.3.2	Primary System Safety Relief Valve Positions (including PORV and code valves) or Flow Through or Pressure in Relief Valve Lines	Closed-not closed	2	Operation status, to monitor for loss of coolant

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.3.2	PORV Position	Closed-not closed	ZS-455A	Y	021	Y	-	-	BOP
			ZS-456A	Y	021	Y	-	-	BOP
D.3.2	PORV Block Valve Position	Closed-not closed	ZS-8000A	Y	021	Y	-	-	BOP
			ZS-8000B	Y	021	Y	-	-	BOP
D.3.2	Safety Valve Position	Closed-not closed	ZS-8010A	Y	021	Y	-	-	BOP
			ZS-8010B	Y	021	Y	-	-	BOP
			ZS-8010C	Y	021	Y	-		BOP

III. REMARKS

1. The design meets the stated recommendations. Section 18.2.6.2 provides more information on these items.

2. Since the design provides position monitoring of the subject valves, the flow through or pressure in the discharge lines to the PRT is not provided.

3. Diversity is not required, since this is an NRC Category 2 variable. However, the PRT parameters described on data sheet 2.8 are available.

TABLE 7A-3 (Sheet 11)

DATA SHEET 2.6

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.3.3	Pressurizer Level	Bottom to top	1	To ensure proper operation of pressurizer

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.3.3	Pressurizer Level	Bottom to top of straight shell	LT-459	Y	002	Y	002	N	NSSS
			LT-460	Y	002	Y	Select 1 of 3		NSSS
			LT-461	Y	002	Y			NSSS

III. REMARKS

1. The range covered meets the intent of the recommended range. Approximately 85 percent of the total volume is covered. Monitoring level in the hemispherical heads is not advisable, since the volume-to-level ratio is not linear.

2. This is a Type A variable, and is used throughout the EOIs for operator action.

3. Diversity is not required due to the extensive redundancy provided.

TABLE 7A-3 (Sheet 12)

DATA SHEET 2.7

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.3.4	Pressurizer Heater Status	Electric current	2	To determine operating status

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.3.4	Pressurizer	0-300A	CT-NB0106	Y	015	Y	-	-	BOP
	Heater Current	0-300A	CT-NB0208	Y	015	Y	-	-	BOP

III. REMARKS

1. The Callaway design meets the stated recommendations.

2. Diversity is not required, since this is an NRC Category 2 variable.

TABLE 7A-3 (Sheet 13)

DATA SHEET 2.8

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.3.5	Quench Tank Level	Top to bottom	3	To monitor operation
D.3.6	Quench Tank Temperature	50°F to 750°F	3	To monitor operation
D.3.7	Quench Tank Pressure	0 to design pressure[4]	3	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.3.5	Pressurizer Relief Tank Level	Top to bottom	LT-470	N	021	N	-	-	NSSS
D.3.6	Relief Tank Temperature	50 to 350	TE-468	N	021	N	-	-	NSSS
D.3.7	Relief Tank Pressure	0-100 psig (design)	PT-469	N	021	N	-	-	NSSS

III. REMARKS

1. The PRT is a horizontal, cylindrical tank. The level is measured for 100 of the 114-inch tank diameter, which is essentially top to bottom.

2. The PRT temperature range is adequate to monitor any expected conditions in the tank. The PRT design pressure is 100 psig (T_{sat} = 327.8°F), and the rupture disc release pressure is 91 psig, nominal. Following breach of the disc, the temperature of the tank cannot exceed the saturation temperature associated with the existing containment pressure.

3. The PRT parameters are available in the ERFIS and NSSS computers; therefore, it is not necessary to provide a dedicated recorder.

4. Although these instruments are located inside the containment, they are not qualified for post-accident conditions, since they are not required following a LOCA or MSLB. Primary and secondary loop parameters, as well as containment parameters, are available to allow the operator to determine the nature and course of the accident. The EOIs do not indicate any use of these parameters following an event. Refer to Section 7A.3.8.

TABLE 7A-3 (Sheet 14)

DATA SHEET 3.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.1.1	RHR System Flow	0 to 110% design flow[10]	2	To monitor operation
D.1.2	RHR Heat Exchanger Outlet Temperature	32°F* to 350°F	2	To monitor operation and for analysis
D.2.5	Flow in LPI System	0 to 110% design flow [10]	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.1.1	RHR/LPI-Inj./ Recirc. Cold Leg	0-114%	FT-618 FT-619	N N	017 017	N N	018 018	N N	NSSS NSSS
D.2.5	LPI - Hot Leg Recirculation Flow	0-169%	FT-988	N	018	N	-	-	NSSS
D.1.2	RHR Heat Exchanger A Inlet/Outlet Temperatures	50-400°F	TE-612 TE-604	N N	- -	- -	018 018	N N	NSSS NSSS
D.1.2	RHR Heat Exchanger B Inlet/Outlet Temperatures	50-400°F	TE-613 TE-605	N N	- -	- -	018 018	N N	NSSS NSSS

* Revision to Regulatory Guide 1.97 revised the range to 40°F to 350°F

III. REMARKS

1. The proper operation of the RHR system is verified by observing pump and valve status indications provided on the main control board, which contains mimic diagrams of the flow paths. These indications are fully qualified to Class 1E requirements.

2. The RHR system (Figure 5.4-7) serves the dual function of residual heat removal and low pressure injection/recirculation. The flow rates are indicated for all modes of operation; however, they are provided for performance monitoring only. The flow rate and temperature monitoring is not required for any safety-related function and, therefore, the instruments

TABLE 7A-3 (Sheet 15)

DATA SHEET 3.1 (Continued)

III. REMARKS (Continued)

are not Class 1E. The proper operation of the RHR system is verified by observing pump and valve status indications provided on the main control board, which contains mimic diagrams of the flow paths. These indications are fully qualified to Class 1E requirements.

3. Since the sensors/transmitters are part of the pressure boundary, they are designed to remain intact following an SSE; however, functionality is not assured.

4. The RHR injection phase runout flow is limited to 4,428 gpm. The range of FT-618 and 619 is 0 to 5,500 gpm. The RHR hot leg recirculation flow is 2,662 gpm for one RHR pump operating. The range of FT-988 is 0 to 4,500 gpm.

5. Train A flow (FT-618) and temperatures (TE-604 and 612) are recorded on TR-612. Train B flow (FT-619) and temperatures (TE-605 and 613) are recorded on TR-613. The heat exchanger inlet temperatures are not considered to be part of the Regulatory Guide 1.97 data base.

6. The RHR heat exchanger outlet temperature range from 50°F to 400°F is adequate to monitor any expected conditions leaving the heat exchanger. The minimum temperature of the RHR system will be 60°F in the long term following an accident due to the automatic temperature control on the CCW system, which provides cooling water to the RHR heat exchanger. The air-operated temperature control valve which bypasses flow around the CCW heat exchanger is a safety-related qualified valve; however, it is supplied by a nonsafety-related instrument air system. This system will most likely be available during the long term following an accident, and it may be loaded onto the emergency diesel generator.

   If this automatic control is not available, many options exist for operator action to control the CCW and/or RHR temperatures and flows to maintain a minimum RHR heat exchanger outlet temperature at or above 50°F; therefore, the existing range of the outlet temperature indicators is adequate. With the given decay heat, it would take several days for the outlet temperature to approach the low end of the currently monitored range. With operators periodically monitoring RCS water temperature after an accident, it is not deemed credible for the outlet temperature to fall below 50°F with no remedial actions being taken by the operating staff. As evidenced by the Revision 3 change to the low end of the range (from 32°F to 40°F), it is Callaway's position that this required range is arbitrary and not based on plant-specific requirements for post-accident monitoring.

TABLE 7A-3 (Sheet 16)

DATA SHEET 3.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.2.1	Accumulator Tank Level and Pressure	10% to 90% volume 0 to 750 psig	2	To monitor operation
D.2.2	Accumulator Isolation Valve Position	Closed or open	2	Operation status

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.2.1	Accumulator Tank Level (Unnecessary)	13+ inches	LT-950 through 957	N	018	N	-	-	NSSS
D.2.1	Accumulator Tank Pressure (Unnecessary)	0-700 psig	PT-960 through 967	N	018	N	-	-	NSSS
D.2.2	Accumulator Isolation Valves	Closed/Open	ZS 8808AA, AB through DA, DB	Y	018	Y	-	-	BOP

III. REMARKS

1. The accumulator isolation valve position indication requirements are met.

2. Accumulator tank level and pressure indication are unnecessary variables and need not be provided for post-accident monitoring. Therefore, Category 2 instruments are not required. Remark 3 provides additional justification. Remarks 4 and 5 discuss the available pressure and level monitors and their ranges. These remarks also address the adequacy of the existing ranges when compared to the recommended ranges of Table 2 of Regulatory Guide 1.97. Since these variables are unnecessary, the comparison is provided only for information.

3. Table 2 of Regulatory Guide 1.97 lists accumulator pressure and level under Type D variables which are defined therein as: "Type D Variables: Those variables that provide information to indicate the operation of individual safety systems and other systems important to safety. These variables are to help the operator make appropriate decisions in using the individual systems important in mitigating the consequences of an accident."

   Accumulator level and pressure indication do not provide information which is relevant to the defined purpose of a Type D variable. The accumulators are designed to passively inject water into the RCS when the primary pressure falls below the accumulator cover gas pressure (602 to 648 psig per Technical Specifications). The nitrogen cover gas would not be injected until much lower pressures (around 300 psig) are reached. Since the discharge of water from the accumulators is beneficial for transients resulting from RCS breaks, the accumulator discharge valves are locked open and cannot be opened from the control room. Section 15.6 provides RCS depressurization curves for various size LOCAs. The accumulators inject water for all LOCAs analyzed except for the 3-inch LOCA wherein the analysis was terminated at 2500 seconds.

TABLE 7A-3 (Sheet 17)

DATA SHEET 3.2 (Continued)

III. REMARKS (Continued)

If the operator had determined that there is no further need or potential need for accumulator water injection and he desired to preclude the addition of nitrogen during the long-term LOCA recovery phase and if the RCS pressure had not dropped below 300 psig, the operator may vent the accumulators and/or isolate the discharge of the accumulators by directing the power breakers to be unlocked (outside the control room), provided that this action would not violate any procedures.

For a LOCA, there is no need to determine if accumulator water has been injected. If water has been injected, it was needed or at least not adverse to the core.

Should there be a question as to whether the accumulators actually discharged nitrogen into a depressurized but relatively intact primary system, the operator could utilize the pressure and RV level indication to determine if nitrogen was in the pressurizer or the vessel head. These areas can be vented from the control room, it is deemed appropriate.

Other Condition IV events (SGTR and MSLB) do not result in RCS depressurization transients which result in discharge of accumulator nitrogen into the RCS. For these events, the operating staff will isolate or depressurize the accumulators prior to proceeding to a cold shutdown condition. The operating staff has two variables available to them to indicate the successful completion of this action: valve position of the accumulator discharge valves and valve position of the nitrogen vent valves. The operator is capable of isolating or depressurizing the accumulators even with an assumed single failure. Therefore, the accumulator level and pressure indications are unnecessary for these events as well as a LOCA.

4. The range of the accumulator tank pressure transmitter is adequate to monitor any expected pressure in the accumulator. The maximum pressure allowed by the plant Technical Specification is 648 psig. No fluid addition to the tank is expected following an accident due to the check valve in the discharge line from each accumulator. Therefore, there is no need to extend the pressure indication beyond the present 700 psig range.

5. The recommended range of level indication from 10 to 90 percent of tank volume is unnecessary. The plant Technical Specifications require that the content of the tank be maintained within a very narrow range (6061 to 6655 gallons). The instrumentation provided monitors the level of the tank for a span of 13 inches in which the normal level is maintained. Monitoring the level above the Technical Specification value is not required because fluid addition following an accident is not postulated.

   Monitoring the levels between the present range and the recommended range of 10 percent of tank volume is not required because the addition of water contained in that volume, as noted previously, is beneficial and of no concern following an accident.

TABLE 7A-3 (Sheet 18)

DATA SHEET 3.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.2.3	Boric Acid Charging Flow	0-110% design flow[10]	2	To monitor operation
D.2.4	Flow in HPI System	0-110% design flow[10]	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.2.3	ECCS Centrifugal Charging Pump Flow (Boron Inj.)	0-280%	FT-917A	Y	018	Y	-	-	NSSS
		0-280%	FT-917B	Y	018	Y	-	-	NSSS
D.2.4	Safety Injection Pump Flow	0-123%	FT-918	N	017	N	-	-	NSSS
		0-123%	FT-922	N	017	N	-	-	NSSS
D.2.4	Charging to RCP Seals	0-250%	FT-215A	Y	001	Y	-	-	NSSS
		0-250%	FT-215B	Y	001	Y	-	-	NSSS

III. REMARKS

1. The SI pump flow rate is 650 gpm for hot let recirculation. The range of FT-918 and 922 (shown on Figures 6.3-1, Sheet 2) is 0 to 800 gpm. The ECCS centrifugal charging pump flow rate to the boron injection path is RCS pressure-dependent (see Tables 15.6-10 and 15.6-12) for injection and recirculation. The range of FT-917A and 917B (shown on Figure 6.3-1, Sheet 3) is 0 to 1,000 gpm.

2. The flow to the RCP seals (shown on Figure 9.3-8) is provided by the normal charging pump or ECCS centrifugal charging pumps, as described in Section 9.3.4. The normal flow rate is 32 gpm (8 gpm per pump). This flow path is also utilized as part of safe shutdown with only safety-related equipment. Refer to Appendix 5.4A. The range of FT-215A and 215B is 80 gpm.

3. The safety injection flow is provided for performance monitoring only and is not required following an accident; therefore, the transmitters are not Class 1E. The ECCS centrifugal charging pump flow elements/transmitters are used during safe shutdown; therefore, they are Class 1E.

TABLE 7A-3 (Sheet 19)

DATA SHEET 3.4

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.2.6	Refueling Water Storage Tank Level	Top to bottom	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.2.6	Refueling Water Storage Tank Level	Top to bottom	LT-930	Y	018	Y	018	N	NSSS
			LT-931	Y	018	Y	018	N	NSSS
			LT-932	Y	018	Y	-	-	NSSS
			LT-933	Y	018	Y	-	-	NSSS

III. REMARKS

1. The RWST level instrumentation is shown on Figure 6.3-1, Sheet 1, and fully meets the stated requirements.

2. The RWST level indications and alarms are utilized during switchover from injection to recirculation in a 2-out-of-4 logic. RWST level is a Type A variable, per the assumptions stated in Section 7A.3.1.

TABLE 7A-3 (Sheet 20)

DATA SHEET 4.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.4.1	Steam Generator Level	From tube sheet to separators	1	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.4.1	Steam Generator Level - Wide Range	13 inches above tube sheet to separators	LT-501	Y	025	Y	026	N	NSSS
			LT-502	Y	025	Y	026	N	NSSS
			LT-503	Y	025	Y	026	N	NSSS
			LT-504	Y	025	Y	026	N	NSSS
NA	Steam Generator Level - Narrow Range	150 inches	LT-517, 518, 519, LT-527,528,529	Y	026	Y	-	-	NSSS
				Y	026	Y	-	-	NSSS
			LT-537,538,539	Y	026	Y	-	-	NSSS
			LT-547,548,549	Y	026	Y	-	-	NSSS
			LT-551,2,3&4	Y	025	N	-	-	NSSS

III. REMARKS

1. The steam generator wide range instrumentation provides level indication from 13 inches above the tube sheet to the moisture separators (a range of 573 inches) and meets the intent of the recommended range. The steam generator is essentially dry when the level drops below the lower tap (less than 450 gallons).

2. The four narrow range level transmitters on each loop are fully qualified and are considered to be a Type A variable per the assumptions stated in Section 7A.3.1. The narrow range transmitters are used to identify a steam generator tube rupture.

3. The narrow range instruments provide diverse indications within their range (437 to 587 inches above the tube sheet) and would indicate the failure (high or low) of a wide range instrument.

4. Wide range steam generator level measurement meets the intent of the single failure criterion for Category 1 variables by virtue of independent, diverse variables. In the Callaway emergency procedures, auxiliary feedwater (AFW) flow, reactor coolant pressure, and reactor coolant temperature indications are diverse variables which are used to determine whether adequate core cooling is provided in the absence of wide range level indication on one steam generator. The Callaway design of having one wide range level indicator, in conjunction with one AFW flow indicator, per steam generator is consistent with NUREG-0737 Item II.E.1.2 for Westinghouse plants (see Section 18.2.8.1).

TABLE 7A-3 (Sheet 21)

DATA SHEET 4.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.4.2	Steam Generator Pressure	From atmospheric pressure to 20 percent above the lowest safety valve setpoint	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.4.2	Steam Line Pressure	0-1,300 psig (0-110% above lowest safety valve setpoint)	PT-514,5,6	Y	026	Y	026 (PT-514)	N	NSSS
			PT-524,5,6	Y	026	Y	026 (PT-524)	N	NSSS
			PT-534,5,6	Y	026	Y	026 (PT-535)	N	NSSS
			PT-544,5,6	Y	026	Y	026 (PT-545)	N	NSSS
NA	Steam Line Pressure for PORV Operation	0-1,500 psig 126%	PT-1	Y	006	Y	-	-	-
			PT-2	Y	006	Y	-	-	-
			PT-3	Y	006	Y	-	-	-
			PT-4	Y	006	Y	-	-	-

III. REMARKS

1. The lowest safety valve setpoint is 1,185 psig. The steam line pressure transmitters have a range of 0 to 1,300 psig, which is 110 percent above the lowest setpoint. Assuming a repeatability factor of ±3 percent total channel accuracy of the steam line pressure monitoring channels, a margin of 40 psi exists between the upper range of the steam line pressure transmitters and the opening setpoint of the lowest safety valve.

   In addition, the Callaway atmospheric relief valves are fully qualified and available for controlled heat removal and steam generator level control by maintaining a steam discharge rate approximately equal to the auxiliary feedwater addition rate.

   These atmospheric relief valves are set at 1140 psig and would lift prior to the safety valve with the lowest set pressure. The operation of these valves provides another 45 psi margin between the opening of a relief valve and the 1300 psig range of the steam line pressure indicators. Using this setpoint, the steam line pressure transmitters have a range of 0 to 114 percent. The existing range of 0 to 1300 psig is adequate for the Callaway design since it provides sufficient margins above the expected secondary side pressures.

2. The steam line pressure transmitters used for PORV operation have a range of 0 to 1,500 psig, which is 126 percent of the lowest setpoint. These instruments are not considered part of the RG 1.97 data set per the assumptions stated in Section 7A.3.2 and are not inputted to the ERFIS data systems. These instruments are fully qualified and meet the requirements of Category 2 instrumentation.

TABLE 7A-3 (Sheet 22)

DATA SHEET 4.2 (Continued)

III. REMARKS (Continued)

3. The steam line pressure is a Type A variable per the assumptions stated in Section 7A.3.1, and is used to detect an SGTR and secondary side break and to identify the affected steam generator.

TABLE 7A-3 (Sheet 23)

DATA SHEET 4.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.4.3	Safety/Relief Valve Positions or Main Steam Flow	Closed - not closed	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.4.3	Atmospheric Relief Valve Position (PORV)	Closed - not closed	ZS-1	Y	006	Y	-	-	BOP
			ZS-2	Y	006	Y	-	-	BOP
			ZS-3	Y	006	Y	-	-	BOP
			ZS-4	Y	006	Y	-	-	BOP
D.4.3	Safety Valve Position (20 valves)	See Note 2							

III. REMARKS

1. The atmospheric relief valve (PORV) position fully meets the stated requirements.

2. The number of safety valves open is determined by the radiological release information system (RRIS) computer using main steam flow and other valve positions (main steam isolation valves, condenser dump valves, atmospheric relief valves).

TABLE 7A-3 (Sheet 24)

DATA SHEET 4.4

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.4.4	Main Feedwater Flow	0-110 percent design flow[10]	3	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.4.4	Main Feedwater Flow	0-120 percent of VWO flow	FT-510	N	026	N	006	N	NSSS
			FT-511	N	026	N	-	-	NSSS
			FT-520	N	026	N	006	N	NSSS
			FT-521	N	026	N	-	-	NSSS
			FT-530	N	026	N	006	N	NSSS
			FT-531	N	026	N	-	-	NSSS
			FT-540	N	026	N	006	N	NSSS
			FT-541	N	026	N	-	-	NSSS

III. REMARKS

1. The Callaway design meets all of the stated recommendations.

2. The flow transmitter has a range from 0 to 4.8 x 10^6 lbs/hr. The VWO flow is 3.99 x 10^6 lbs/hr for each line (based on 0% steam generator tube plugging; see Tables 10.3-2 and 10.4-6).

TABLE 7A-3 (Sheet 25)

DATA SHEET 5.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.5.1	Auxiliary or Emergency Feedwater Flow	0-110 percent design flow[10]	2 (1 for B & W plants)	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.5.1	Auxiliary Feedwater Flow	0-160%	FT-1	Y	006	-	-	-	BOP
			FT-2	Y	006	-	-	-	BOP
			FT-3	Y	006	-	-	-	BOP
			FT-4	Y	006	-	-	-	BOP
NA		0-160%	FT-7	Y	-	-	-	-	BOP
			FT-9	Y	-	-	-	-	BOP
			FT-11	Y	-	-	-	-	BOP

III. REMARKS

1. The auxiliary feedwater system is described in Section 10.4.9 and shown on Figure 10.4-9.

2. Auxiliary feedwater flow to each steam generator is monitored by Class 1E flow loop. Each flow transmitter is powered by a different separation group (1 through 4) corresponding to the power supply for the steam line PORV. Only two of the four steam generators are required to establish a heat sink for the RCS. The required flow indication to two intact steam generators is assured assuming a single failure.

3. A comparison of the AFWS to the NUREG-0737 requirements for reliability and flow indication is provided in Section 18.2.7 which shows complete compliance to all recommendations.

4. The flow transmitters have a range of 0 to 400 gpm. The design flow the steam generators is 250 gpm for a normal shutdown. For a MSLB the design flow to two intact steam generators is 500 gpm (250 gpm each).

TABLE 7A-3 (Sheet 26)

DATA SHEET 5.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.5.2	Condensate Storage Tank Level	Plant Specific	1	To ensure water supply for auxiliary feedwater (Can be Category 3 if not primary source of AFW. Then whatever is primary source of AFW should be listed and should be Category 1.)

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.5.2	Condensate Storage Tank Level (indicated by pump suction pressure)	Top to bottom	PT-24 PT-25 PT-26	Y Y Y	005 005 005	Y Y Y	- - -	- - -	BOP BOP BOP
NA	Condensate Storage Tank Level (for automatic AFWS switchover)	Appropriate for automatic switchover to ESW	PT-37 PT-38 PT-39	Y Y Y	026 026 026	Y Y Y	- - -	- - -	BOP BOP BOP
NA	Condensate Storage Tank Level	0-100%	LT-4	N	005	N	-	-	BOP

III. REMARKS

1. The CST is shown on Figure 9.2-12, and the pressure transmitters are shown on Figure 10.4-9. As stated in Section 10.4.9, the CST level will be determined by PT-24, 25, and 26. The automatic switchover to ESW upon the depletion of CST water volume will be initiated by PT-37, 38, and 39. LT-4 is non-safety grade and provides a direct level reading; however, this instrument is not considered part of the RG 1.97 data base.

2. Since there is no manual action required for switchover to the alternate source of auxiliary feedwater (ESW), the CST level measurements are not Type A variables.

TABLE 7A-3 (Sheet 27)

DATA SHEET 6.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.3.3	Containment Pressure[1]	0 to design pressure[4] (psig)	1	Function detection accomplishment of mitigation, verification
B.4.2	Containment Pressure[1]	10 psia to design pressure[4]	1	Same
C.2.2	Containment Pressure[1]	10 psia to design pressure[4] , psig (5 psia for subatmospheric containments)	1	Detection of breach, accomplishment of mitigation, verification, long-term surveillance
C.3.3	Containment Pressure[1]	10 psia to 3 times design pressure[4] for concrete (4 times design pressure for steel) (5 psia for subatmospheric containments)	1	Detection of potential for or actual breach, accomplishment of mitigation, verification

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.3.3 B.4.2 C.2.2	Containment Pressure (normal design range)	0-69 psig	PT-934 PT-935 PT-936 PT-937	Y Y Y Y	018 018 018 018	Y Y Y Y	018 018 018 018	N N - -	NSSS NSSS NSSS NSSS
C.3.3	Containment Pressure - Wide Range	-5 to 180	PT-938 PT-939	Y Y	020 020	Y Y	020 020	N N	NSSS NSSS
NA	Containment Pressure (normal operating range)	-3 to +3 psig	PDY-40	N	020	N	-	-	BOP

III. REMARKS

1. The Callaway design meets all of the stated requirements.

2. The design pressure of the containment is 60 psig. The peak calculated pressure following a LOCA and MSLB are described in Section 6.2. As stated in Section 7A.3.2, diversity is not required in extended ranges not associated with DBEs.

TABLE 7A-3 (Sheet 28)

DATA SHEET 6.1 (Continued)

III. REMARKS (Continued)

3. Monitoring of subatmospheric conditions recommended in items B.4.2, C.2.2, and C.3.3 is accomplished by the wide range instruments.

4. Normal containment pressure will be maintained near atmospheric pressure and measured by pressure transmitters located inside and outside of the containment. The difference in pressures will be indicated in the control room. This instrumentation is not part of the Regulatory Guide 1.97 data base.

TABLE 7A-3 (Sheet 29)

DATA SHEET 6.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.3.2	Containment Sump Water Level[1]	Narrow range (sump) Wide range (bottom of containment to 600,000-gallon level equivalent)	2 1	Function detection, accomplishment of mitigation, verification
C.2.3	Containment Sump Water Level[1]	Narrow range (sump) Wide range (bottom of containment to 600,000-gallon level equivalent)	2 1	Detection of breach, accomplishment of mitigation, verification, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.3.2	Normal Sump	836,000 gallons	LIT-9	Y	018	Y	-	-	BOP
C.2.3	Water Level		LIT-10	Y	018	Y	020	Y	BOP
NA	Recirculation	576,000 gallons	LIT-7	Y	018	Y	-	-	BOP
	Sump Level		LIT-8	Y	018	Y	020	Y	BOP

III. REMARKS

1. Refer to Section 18.2.12.2 for a comparison with NUREG-0737 requirements.

2. The Callaway design provides for Class 1E level monitoring in each of the two containment normal sumps and above each of the two recirculation sumps. The bottoms of the normal and recirculation sumps are at Elevations 1,995 feet and 1,992 feet, respectively. The levels in each normal sump are monitored from 6 inches above the sump bottoms for the next 156 inches. The LOCA results in the maximum flood level of 2004'-6" (348,000 gallons, minimum). The normal sump level extends to 2008'-6", providing ~4 feet of range above the maximum flood level.

3. The normal sumps are provided with twin level elements which are indicated on one continuous indicator. The recirculation sump level instruments monitor containment water level above the recirculation sump curb. The monitored level begins at elevation 2000’ - 6”. Redundancy is provided in each type of sump. Diversity is not required, since there are four independent water level measurements.

The normal sump level is a Type A variable for Callaway. The normal sump level is used for event identification. The recirculation sump level is not a Type A variable. Although the recirculation sump level could be used for event identification, it is not required and would not respond following an event since its range begins at the top of the 6-inch of curb

TABLE 7A-3 (Sheet 30)

DATA SHEET 6.2 (Continued)

III. REMARKS (Continued)

around the sump. Similarly, since switchover to recirculation is initiated automatically on low RWST level, verification of containment water level is not required nor part of a preplanned manual safety function. Refer to Section 7A.3.1.

TABLE 7A-3 (Sheet 31)

DATA SHEET 6.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
B.4.1	Containment Isolation Valve Position (excluding check valves)	Closed - not closed	1	Accomplishment of isolation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
B.4.1	Containment Isolation Valve Position (excluding manual and check valves)	Closed - not closed	See Figure 6.2.4-1	Y	Misc.	Y	-	-	BOP

III. REMARKS

1. Refer to Section 6.2.4 and 18.2.11 for discussions of containment isolation. As noted in Section 6.2.4, manual valves do not have position indication in the control room. The position of the manual valves is verified on a periodic basis in accordance with the Technical Specifications In addition, these valves are under administrative control and are locked or sealed closed whenever containment integrity is required.

TABLE 7A-3 (Sheet 32)

DATA SHEET 6.4

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
C.3.2	Containment Hydrogen Concentration	0 to 10% (capable of operating from 10 psia to maximum design pressure[4])	3	Detection of potential for breach, accomplishment of mitigation, long-term surveillance
E.6.3.1	Hydrogen Content	0 to 10%	3	Release assessment, verification analysis

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
C.3.2 E.6.3.1	Containment Hydrogen Concentration	0-10%	AT-10	Y	020	Y	020	Y	BOP
			AT-19	Y	020	Y	-	-	BOP

III. REMARKS

1. The hydrogen analyzers are described in Section 6.2.5 and shown on Figure 6.2.5-1.

2. The hydrogen analyzers meet all of the stated requirements. Refer to Section 18.2.12.2 for a comparison with NUREG-0737 requirements. The analyzers will operate properly within the recommended containment pressure ranges.

3. RG 1.97, Revision2, Table 2 recommends Category 1. However, the hydrogen analyzers are Category 3, as defined in RG 1.97, per 10 CFR 50.44 as amended by the NRC effective October 16, 2003.

TABLE 7A-3 (Sheet 33)

DATA SHEET 6.5

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.6.3	Containment Atmosphere Temperature	40°F to 400°F	2	To indicate accomplishment of cooling

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.6.3	Containment Atmosphere Temperature	0-400°F	TE-60	Y	018	Y	-	-	BOP
			TE-61	Y	018	Y	-	-	BOP
			TE-62	Y	018	Y	-	-	BOP
			TE-63	Y	018	Y	020	Y	BOP

III. REMARKS

1. The Callaway design meets all of the stated recommendations.

2. The Callaway design utilizes containment pressure to verify that containment heat removal is being accomplished. Refer to data sheet 8.1 for a further discussion.

3. Containment temperature is not a Type A variable, since it does not meet the requirements discussed in Section 7A.3.1.

TABLE 7A-3 (Sheet 34)

DATA SHEET 6.6

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.6.4	Containment Sump Water Temperature	50°F to 250°F	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.6.4	Containment Sump Water Temperature (unnecessary variable)								

III. REMARKS

1. This variable is unnecessary for the Callaway Plant. The recommended purpose is to "monitor operation"; however, there is no system at Callaway for it to monitor. Containment cooling is monitored by the air temperature monitors described on data sheet 6.5.

2. Sump temperature is not required for RHR operation or assurance of NPSH available, since NPSH calculations conservatively assume saturated water was present. See Safety Evaluation Eleven of Section 6.2.2.1.3 and Table 6.2.2-7.

3. Primary system, PRT, and other containment parameters are all available to help determine the plant conditions. Sump level indications indicate the amount of water, and the other parameters indicate its source.

4. Note that proper RHR functions during the recirculation mode are provided by other variables described on data sheet 3.1.

5. The Callaway SER (NUREG-0830) in Section 6.2.1.1 (page 6-4) indicates that the NRC Staff agrees that this variable is not necessary and finds this exception to the guidelines of Regulatory Guide 1.97 acceptable.

6. The Callaway SER also addresses the containment heat removal systems and similarly finds them acceptable. Page 6-10 indicates that the RHR system serves to remove heat from the containment during the recirculation mode following a LOCA by cooling the containment sump fluid in the RHR heat exchanger. During this mode of operation, the RHR inlet temperature monitors described on Data Sheet 3.1 would provide indication of the containment sump water temperature. As noted on Data Sheet 3.1, the RHR heat exchanger inlet temperature is not considered to be part of the Regulatory Guide 1.97 data base.

TABLE 7A-3 (Sheet 35)

DATA SHEET 7.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.7.1	Makeup Flow - In	0 to 110% design flow[10]	2	To monitor operation
D.7.2	Letdown Flow - Out	0 to 110% design flow[10]	2	To monitor operation
D.7.3	Volume Control Tank Level	Top to bottom	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.7.1	Normal Charging Flow	50 to 267%	FT-121	N	002	N	-	-	NSSS
D.7.2	Normal Letdown Flow	0 to 267%	FT-132	N	002	N	-	-	NSSS
D.7.3	Volume Control Tank Level	Top to bottom of straight shell	LT-185	Y	002	Y	-	-	-
			LT-112	Y	002	Y	-	-	-
			LT-149	N	-	-	-	-	NSSS
D.7.2	Safety Related Letdown	0 to 167%	FT-138A	Y	001	Y	-	-	NSSS
		0 to 167%	FT-138B	Y	001	Y	-	-	NSSS

III. REMARKS

1. The normal charging and letdown flow rates are described on this data sheet. The DBA-related portion of the charging system is described on data sheet 3.3.

2. The volume control tank level is Class 1E to ensure a suction source from the RWST (automatically) on low VCT level.

3. The level of the VCT is monitored for the straight shell portion only. The span is 75 inches. The hemispherical heads are not monitored, since the volume-to-level ratio is not linear.

4. Appendix 5.4A describes the safety grade cold shutdown system provided in the SNUPPS design. As part of this design, a Class 1E letdown system is provided to the PRT through the excess letdown heat exchanger. FT-138A and B have a range of 0 to 50 gpm. The maximum emergency letdown flow rate at RCS loop temperatures above 400°F is 30 gpm. The maximum emergency letdown flow at less than or equal to 400°F is 50 gpm.

TABLE 7A-3 (Sheet 36)

DATA SHEET 8.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.6.2	Heat Removal by the Containment Fan Heat Removal System	Plant specific	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.6.2	Containment Cooler Heat Removal - (unnecessary variable)								

III. REMARKS

1. Quantification of the amount of heat being removed by the containment fan coolers is an unnecessary variable and is not provided for Callaway. The accomplishment of post-accident heat removal is verified by monitoring the operation of the fan coolers and monitoring the containment pressure and air temperature. Containment pressure and air temperature monitors are described on Data Sheets 6.1 and 6.5.

2. Monitoring of containment air cooler operation is provided by three sets of indications, all of which are safety-related and qualified for post-accident operation. These items do indicate that the air coolers are operating; however, they do not quantify the amount of heat being removed from the containment atmosphere.

   The handswitches for each containment air cooler fan are provided with lights which indicate the mode of operation (stop, slow, or fast) for each containment air cooler.

   The ESF status panel indicates whether the fan coolers are being provided with power (control and fan power supply). If the control fuse blows or if the power breaker trips, a red trouble light appears on one of the ESF status panel windows "Ctmt Cooler Fan SGN01A (B, C or D)." Also, an audio alarm is generated.

   The containment isolation valves serving each set of two containment air coolers are also provided with Class 1E hand indication switches in the control room. These position switches indicate that the isolation valves are open and that the lines to each cooler are capable of passing the cooling water flow. Since the containment isolation valves are normally open and receive a confirmatory open signal on the receipt of a safety injection signal, the ESF status panel also contains windows for these valves. A red light will appear and an audio alarm will be sounded if any valve fails to take its post-accident position (open).

   On Callaway, the heat removal capability of the containment air coolers is accurately determined by sophisticated mathematical and computer modeling developed by the air cooler supplier. The accuracy of the model was verified during the prototype testing of three different coils at three different post-accident pressures. Topical Report AAF-TR-7101

TABLE 7A-3 (Sheet 37)

DATA SHEET 8.1 (Continued)

III. REMARKS (Continued)

(Reference 1 of FSAR Section 6.2.2.3) provides a comparison of the measured heat removal during the tests to the computer analysis predictions. The comparisons show very close agreement between the predicted and actual heat removal abilities. The NRC has approved the topical report for reference in construction permit and operating license applications.

3. During the transient of an accident, heat removal by air coolers cannot be used by an operator, since too many variables are changing rapidly. The amount of energy released to the containment cannot be accurately quantified. Heat removal mechanisms are those identified in Section 6.2.1 and include heat transfer to passive heat sinks, containment sprays, and containment air coolers. The operator must determine what equipment is operating and watch the changes in containment pressure, temperature, sump level, and radiation levels to determine the nature of the accident.

4. The operability of the air coolers is verified periodically throughout the life of the plant in accordance with Technical Specification Paragraph 4.6.2.3, which ensures the proper operation of the system.

TABLE 7A-3 (Sheet 38)

DATA SHEET 9.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.8.1	Component Cooling Water Temperature to ESF System	32°F* to 200°F	2	To monitor operation
D.8.2	Component Cooling Water Flow to ESF System	0 to 110% design flow[10]	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.8.1	CCW Heat Exchanger Discharge Temperature	0-200°F	TE-31	Y	019	Y	-	-	BOP
			TE-32	Y	019	Y	-	-	BOP
D.8.2	CCW Pump Discharge Flow	0-137 percent	FT-95	N	-	-	-	-	BOP
			FT-96	N	-	-	-	-	BOP
			FT-97	N	-	-	-	-	BOP
			FT-98	N	-	-	-	-	BOP

III. REMARKS

1. The component cooling water system is described in Section 9.2.2. The Callaway design meets the recommended ranges.

2. Section 7A.3.7 describes the qualification of NRC Category 2 variables, as provided for Callaway. The instruments described herein are located outside of the containment in areas served by Class 1E room coolers. These instruments are not required for the proper operation of the system; rather, they are provided for performance monitoring only.

3. Since these instruments are part of the system pressure boundary, they are seismically designed to ensure integrity of the system boundary.

*Revision 3 of Regulatory Guide 1.97 revised the range to 40°F to 200°F.

TABLE 7A-3 (Sheet 39)

DATA SHEET 10.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.6.1	Containment Spray Flow	0-110% design flow[10]	2	To monitor operation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.6.1	Containment Spray Flow	0-126% (design flow - injection)	FT-5	N	017	N	-	-	BOP
		0-106% (design flow - recirculation)	FT-11	N	017	N	-	-	BOP

III. REMARKS

1. The containment spray system is described in Section 6.2.2. The spray system need only operate during the injection phase for cooling purposes. During this phase, the flow rate monitor exceeds the recommended range.

2. Section 7A.3.7 describes the qualification of NRC Category 2 items, as provided for Callaway. These instruments are located outside of the containment in areas served by Class 1E room coolers. These instruments are provided for performance monitoring and not to allow proper system operation.

3. The instruments are part of the pressure boundary and are seismically designed to ensure its integrity.

4. Class 1E operability indications for each containment spray train are provided in the control room. All motor-operated valves in the flow paths are provided with hand indication switches and receive a CSAS to open. The containment spray pumps also have hand switches and start automatically on a CSAS. The ESF status indication panel provides backup information on a component and system level and indicates the system's status. Should the power breakers trip or the control fuses blow, an amber light will appear and an audio signal will be generated.

TABLE 7A-3 (Sheet 40)

DATA SHEET 11.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
C.2.4	Containment Area Radiation[1]	1 R/hr to 10^4 R/hr	3[6,7]	Detection of breach, verification
E.1.1	Containment Area Radiation - High Range[1]	1 R/hr to 10^7	1[6,7]	Detection of significant releases, release assessment, long-term surveillance, emergency plant actuation

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
C.2.4	Containment Area Radiation	1 to 10^8 R/hr	RE-59	Y	067	Y	-	-	BOP
E.1.1			RE-60	Y	067	Y	20	Y	BOP

III. REMARKS

1. These instruments meet all of the stated recommendations and are further described in Section 18.2.12.2.

2. As described in Section 7A.3.2, diverse variables are performance grade. Diversity for containment area radiation is provided by portable survey equipment with the capability to detect gamma radiation over the required range as described in data sheet 17.3. Also the Callaway design includes area radiation monitors with a range to 10 R/hr located inside the containment.

3. This is a Type A variable and is used for event identification in the EOIs.

TABLE 7A-3 (Sheet 41)

DATA SHEET 11.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
C.3.5	Radiation Exposure Rate (inside buildings or areas, e.g., auxiliary building, reactor shield building annulus, fuel handling, which are in direct contact with primary containment where penetrations and hatches are located)[1]	10^{-1} R/hr to 10^{4} R/hr	2[7]	Indication of breach
E.2.1	Radiation Exposure Rate[1] (inside building or areas where access is required to service equipment important to safety)	10^{-1} R/hr to 10^{4} R/hr	2[7]	Detection of significant releases, release assessment, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
C.3.5	Radiation Exposure Rate	(Unnecessary Variable)							
E.2.1									

III. REMARKS

1. Area radiation monitors are shown on Figure 12.3-2 and are provided in accordance with the criteria stated in Section 12.3.4.1. Process and effluent monitors are provided in accordance with the criteria stated in Section 11.5. Area monitors are provided in the corridors of the auxiliary building and not in the penetration areas or equipment spaces. As described in Section 12.3.4.2.2.2.9, a portable monitor may be used to determine the conditions in any equipment space.

2. The process and effluent monitors will provide indication of releases and/or breaches in the systems in operation following an event. Use of extended range area monitors in the areas adjacent to the containment are not appropriate since the background, direct radiation levels can be expected to be quite high. The process and effluent monitors provide the required public protection.

3. The existing area radiation monitors provide for adequate employee protection with their range to 10R/hr. Should this range be exceeded, employee entry will be prohibited until dose rates have been established by portable instrumentation.

4. Exposure rate monitors associated with variable C.3.5 were deleted in Revision 3 of Regulatory Guide 1.97.

TABLE 7A-3 (Sheet 42)

DATA SHEET 12.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
C.3.4	Containment Effluent Radioactivity - Noble Gases from Identified Release Points[1]	10^{-6} μCi/cc to 10^{-2} μCi/cc	2[8,9]	Detection of breach, accomplishment of mitigation, verification
C.3.6	Effluent Radioactivity[1] Noble Gases (from buildings or areas where penetrations and hatches are located)	10^{-6} μCi/cc to 10^{3} μCi/cc	2[8]	Indication of breach
E.3.1.1	Containment of Purge Effluent	10^{-6} μCi/cc to 10^{5} μCi/cc 0 to 110% vent design flow[10] (Not needed if effluent discharges through common plant vent)	2[8]	Detection of significant releases; release assessment
E.3.1.3	Auxiliary Building[1] (including any building containing primary system gases, e.g., waste gas decay tank)	10^{-6} μCi/cc to 10^{3} μCi/cc 0 to 110% vent design flow[10] (Not needed if effluent discharges through common plant vent)	2[8]	Detection of significant releases, release assessment, long-term surveillance
E.3.1.5	Common Plant Vent or Multipurpose Vent Discharge Any of above Releases (if containment purge is included)	10^{-6} μCi/cc to 10^{3} μCi/cc 0 to 110% vent design flow[10] 10^{-6} μCi/cc to 10^{4} μCi/cc	2[8]	Detection of significant releases, release assessment, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
C.3.4 E.3.1.5	Plant Unit Vent Wide Range Gas	10^{-7} to 10^{5} μCi/cc	GT-RE-21B	N	SP010	N	SP010	N	RRIS
	Radwaste Building Wide Range Gas	10^{-7} to 10^{5} μCi/cc	GH-RE-10B	N	SP010	N	SP010	N	RRIS

TABLE 7A-3 (Sheet 43)

DATA SHEET 12.1 (Continued)

III. REMARKS

1. The plant unit vent receives the discharge from the containment purge, auxiliary building, control building, fuel building, and the condenser air removal filtration system. The radwaste building vent receives the discharge from the radwaste building exhaust fans. The radwaste building contains the waste gas decay tanks.

2. The unit vent flow rate is determined by fan run contacts which are inputted to the RRIS computer. Each system is balanced and assumed to be operating at the design flow. The high range monitor has an isokinetic flow monitor. These provisions adequately meet the requirements of the item.

3. The radwaste building vent is a constant flow vent receiving the discharge of the radwaste building exhaust fans. Flow rate monitoring is not required. The high range monitor for the radwaste building vent also has an isokinetic nozzle.

TABLE 7A-3 (Sheet 44)

DATA SHEET 12.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
C.2.5	Effluent Radioactivity - Noble Gas Effluent from Condenser Air Removal System Exhaust[1]	10^{-6} to 10^{-2} μCi/cc	3[8]	Detection of breach, verification
E.3.1.4	Condenser Air Removal Exhaust[1]	10^{-6} to 10^{5} μCi/cc 0 to 110 percent vent design flow[10] (not needed if effluent discharges through common plant vent)	2[8]	Detection of significant releases, release assessment

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
C.2.5	Condenser Air Removal Exhaust Radioactivity	10^{-7} to 10^{-2} μCi/cc	RE-92	N	056	N	056	N	RRIS
E.3.1.4	Condenser Air Removal Exhaust (not required-discharge through plant vent)								

III. REMARKS

1. The condenser air removal exhaust discharges through the plant vent: therefore, the monitor for item E.3.1.4 is not required. The existing condenser air removal exhaust monitor meets the requirements of item C.2.5.

TABLE 7A-3 (Sheet 45)

DATA SHEET 12.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.3.1.6	Vent from Steam Generator Safety Relief Valves or Atmospheric Dump Valves	10^{-1} μCi/cc to 10^{3} μCi/cc (duration of releases in seconds and mass of steam per unit time)	2[12]	Detection of significant release assessment

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
E.3.1.6	Vent from Steam Generator Safety Relief Valves or Atmospheric Dump Valves	4.06×10^{-2} μCi/cc to 4.06×10^{-3} μCi/cc	RE-111	N	SP010	N	SP010	N	RRIS
			RE-112	N	SP010	N	SP010	N	RRIS
			RE-113	N	SP010	N	SP010	N	RRIS
			RE-114	N	SP010	N	SP010	N	RRIS

III. REMARKS

1. The Callaway Plant monitors the atmospheric relief valve plumes. The atmospheric relief valves are set to open at a lower pressure than the safety relief valves and are Class 1E, highly reliable components. These valves are provided with position indication. It is assumed that the relief valves will be open and releasing the same concentration and distribution of radionuclides any time any of the safety valves on the same steam line are open.

2. Radiation detectors will be positioned to view the plume directly from each of the four atmospheric relief valves.

3. Determination of releases from the safety valves and the atmospheric relief valves is made by RRIS computer using main steam pressure and flow and atmospheric relief valve position.

4. SP010 indication range is 1-1E5 mR/hr.

TABLE 7A-3 (Sheet 46)

DATA SHEET 12.4

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.3.1.7	All other Identified Release Points	10^{-6} μCi/cc to 10^{2} μCi/cc 0-110 percent vent design flow[10]	2[8]	Detection of significant releases, release assessment, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
E.3.1.7	Auxiliary Feedwater Pump Turbine Exhaust Monitor	5.51×10^{-2} to 5.51×10^{3} μCi/cc	RE-385	N	SP010	N	SP010	N	RRIS

III. REMARKS

1. A radiation detector monitoring the plume of the auxiliary feedwater turbine exhaust is used to determine the release.

2. This release is from the main steam line; thus, the monitor was designed with the same capabilities as the monitors for steam generator releases (Data Sheet 12.3). The range recommended is not applicable to secondary side releases, as can be seen by the different ranges recommended here and on Data Sheet 12.3.

3. SP010 indication range is 1-1E5 mR/hr.

TABLE 7A-3 (Sheet 47)

DATA SHEET 12.5

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.3.2	Particulates and Halogens			
E.3.2.1	All Identified Plant Release Points (except steam generator safety relief valves or atmospheric steam dump valves and condenser air removal system exhaust). Sampling with Onsite Analysis Capability	10^{-6} μCi/cc to 10^{2} μCi/cc 0 to 110% vent design flow[10]	3[13]	Detection of significant releases, release assessment, long-term surveillance

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
E.3.2.1	Unit Vent Monitors Particulates Iodines	10^{-3} μCi/cc to 10^{2} μCi/cc (See data sheet 12.5, III. Remarks, Note 3	GT-RE-21B	N	N/A	N	-	-	
	Radwaste Building Vent Monitors Particulates Iodines	10^{-3} μCi/cc to 10^{2} μCi/cc (See data sheet 12.5, III. Remarks, Note 3)	GH-RE-10B	N	N/A	N	-	-	

III. REMARKS

1. The Callaway design meets all of the stated recommendations. Refer to Sections 11.5 and 18.2.12.2 for further discussions.

2. Refer to data sheet 12.1 for a discussion of vent flow rate monitoring and wide range gas monitors.

3. The wide range noble gas monitors described on data sheet 12.1 include the capability to obtain grab samples for both halogens and particulates. After collection, laboratory samples will be used to quantify releases.

TABLE 7A-3 (Sheet 48)

DATA SHEET 13.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.6.1	Primary Coolant	Grab Sample	3[5, 18]	Release assessment, verification analysis
E.6.1.1	Gross Activity	10 µCi/ml to 10 Ci/ml		
E.6.1.2	Gamma Spectrum	(Isotopic Analysis)		
E.6.1.3	Boron Content	0 to 6,000 ppm		
E.6.1.4	Chloride Content	0 to 20 ppm		
E.6.1.5	Dissolved Hydrogen or Total Gas[19]	0 to 2,000 cc(STP)/kg		
E.6.1.6	Dissolved Oxygen[19]	0 to 20 ppm		
E.6.1.7	pH	1 to 13		
B.1.3	RCS Soluble Boron Concentration	0 - 6,000 ppm	3	Verification
C.1.3	Analysis of Primary Coolant (Gamma Spectrum)	10 µCi/gm to 10 Ci/gm or TID-14844 source term in coolant volume	3[5]	Detail analysis, accomplishment of mitigation, verification, long-term surveillance
E.6.3	Containment Air	Grab Sample		Release assesment, verification analysis
E.6.3.2	Oxygen Content	0 to 30 percent		Release assesment, verification analysis
E.6.3.3	Gamma Spectrum	(Isotopic Analysis)		Release assesment, verification analysis

TABLE 7A-3 (Sheet 49)

DATA SHEET 13.1 (Continued)

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
E.6.1.1	Gross Activity	Not required							
E.6.1.2 E.6.3.3	Gamma Spectrum								
E.6.1.3	Boron Content								
E.6.3.2	Oxygen Content								
E.6.1.4	Chloride Content								
E.6.1.5	Dissolved Hydrogen								
E.6.1.6	Dissolved Oxygen								
E.6.1.7	pH								

III. REMARKS

1. Approval of Operating License Amendment [144] eliminated the requirement for these variables. Westinghouse WCAP-14986-A, revision 2, provides the technical justification for eliminating PASS criteria specified in Regulatory Guide 1.97 and NUREG-0737.

TABLE 7A-3 (Sheet 50)

DATA SHEET 13.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.6.2	Sump	Grab sample	3[5, 18]	Release assessment, verification analysis
E.6.2.1	o Gross Activity	10μCi/ml to 10 Ci/ml	3	
E.6.2.2	o Gamma Spectrum	(isotopic analysis)	3	
E.6.2.3	o Boron Content	0-6,000 ppm	3	
E.6.2.4	o Chloride Content	0-20 ppm	3	
E.6.2.5	o pH	1 to 13	3	

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
E.6.2	Sump Grab Sample Containment Recirculation	Not required							
	ECCS Pump Room Sumps	Not required							
	Auxiliary Building Sumps	Not required							

III. REMARKS

1. Sampling of the containment sump is considered unnecessary. Westinghouse WCAP-14986-A, revision 2, provides the technical justification for eliminating the containment sump sampling criteria specified in Regulatory Guide 1.97 and NUREG-0737.

2. The ECCS pump room and auxiliary building sumps are provided with Class 1E level indication and operate as described in Section 9.3.3. Process and effluent monitors provide indication of any airborne activity in these sumps since they are directly vented to the auxiliary building normal exhaust system.

3. Sump sampling for the ECCS pump rooms and auxiliary building is considered unnecessary. The Class 1E level indication will detect any accumulated leakage, and the isolation valves will prevent its discharge from the auxiliary building. Should the leakage be from a line that contains fluid from the recirculation sump, the recirculation sump sample will provide the recommended analyses, since the fluid is from the same source.

TABLE 7A-3 (Sheet 51)

DATA SHEET 13.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
C.1.2	Radioactivity Concentration or Radiation Level in Circulating Primary Coolant	1/2 Technical Specification limit to 100 times technical specification, limit R/hr.	1	Detection of breach

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
C.1.2	Radioactivity Concentration (unnecessary variable)								

III. REMARKS

1. As noted in comments provided by the AIF, this variable is unnecessary, and there is no presently available means of providing this information. Also, there is no apparent need or use for this variable which would require its classification as Category I.

TABLE 7A-3 (Sheet 52)

DATA SHEET 14.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.9.1	High-Level Radioactive Liquid Tank Level	Top to bottom	3	To indicate storage volume

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.9.1	Recycle Holdup Tank Level (Unnecessary Variable)								

III. REMARKS

1. The Callaway design precludes the need for this variable. The liquid radwaste system is not required following an event. It is located in the radwaste building, and is controlled from the radwaste building control room. System parameters are not provided in the main control room.

2. The safety grade letdown system is located within the containment, and the containment isolation system is designed to preclude inadvertent discharge from the containment.

3. The recycle holdup tank levels (LT-261 and LT-262) have a range from the top to bottom of the tank and indications are provided in the radwaste building control room. Since the system will only be operated from that room, the control room operators may obtain that status of the tanks from the radwaste building control room personnel. The liquid radwaste system need not be operated during an accident. It may be used during recovery, if the radwaste building is habitable.

4. As noted on Data Sheet 13.2, the auxiliary building and ECCS pump room sumps are provided with Class 1E sump level indication. These sumps would collect any long-term leakage from systems which recirculate fluids from the containment sump. As described in Section 9.3.3 and shown on Figure 9.3-6, Sheet 2, the discharge lines from these sumps contain Class 1E isolation valves which close on a SIS to preclude inadvertent discharge of fluids to the floor drain tank in the radwaste building. The LOCA analysis includes an evaluation of a 2 gpm leak from lines recirculating sump fluids. Refer to Section 15.6.5.4.1.2 for a discussion of the analysis and to Table 15.6-8 for the resulting radiological consequences. Failure of this tank has been analyzed in FSAR Section 15.7.2.

5. The containment normal and instrument tunnel sumps and the reactor coolant drain tank discharge lines are isolated by a CIS-A signal. This signal is generated as a result of a safety injection signal or as a result of high containment pressure. These lines will be isolated subsequent to any LOCA. Refer to Section 18.2.11, which addresses NUREG-0737 Item II.E.4.2, Containment Isolation Dependability. Inadvertent contamination of the radwaste or auxiliary buildings due to discharge of fluids from the containment is precluded by design and is not postulated.

TABLE 7A-3 (Sheet 53)

DATA SHEET 14.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.9.2	Radioactive Gas Holdup Tank Pressure	0-150% design pressure[4]	3	To indicate storage capacity

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.9.2	Gas Decay Tank Pressure (unnecessary variable)								

III. REMARKS

1. The radioactive gas holdup tank is referred to as the gas decay tank (GDT). Pressure is an unnecessary variable for the Callaway design as described in Remark 3 below; however, Remark 2 describes the adequacy of the GDT design and the range of the pressure indicators.

2. Addition of radioactive gases to the gaseous radwaste system following an accident is precluded by design and is not postulated. Containment isolation valves on gas bearing lines from the pressurizer relief tank and the reactor coolant drain tank close upon receipt of a CIS-A. Refer to Remark 5 on Data Sheet 14.1 for a further discussion of containment isolation. Since there will be no containment gases added to the gaseous radwaste system, there is no need to monitor the available storage capacity following an accident.

3. The design pressure of each of the eight GDTs is 150 psig. Each tank is provided with a pressure transmitter/indicator/alarm. The indicators are located in the radwaste building control room and have a range of 0 to 150 psig. The alarms for the six GDTs used during normal operation are set at 100 psig. Two of the GDTs are used for shutdown and start-up. All GDTs are provided with relief valves set at or below the tank's design pressure. The relief valves for the six GDTs discharge at design pressure to the shutdown GDTs which are normally at low pressure. Should an extended discharge to the shutdown GDT occur, a high alarm (at 90 psig) would be received prior to the lifting of the shutdown GDT relief valve at 100 psig. The discharge from the radwaste building vent is monitored by the radwaste building vent monitor described on Data Sheet 12.1. Failure of one of these tanks has been analyzed in FSAR Section 15.7.1.

   Based upon the protection afforded by the installed tank relief valves and the potential eventual release to the radwaste building vent, the span of 0 to tank design pressure is adequate to provide information to the operating staff concerning the status of the GDTs.

TABLE 7A-3 (Sheet 54)

DATA SHEET 15.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.10.1	Emergency Ventilation Damper Position	Open-closed status	2	To indicate damper status

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.10.1	Safety Related Damper Position	Open-closed	HIS-XX	Y	020 068 019	Y	-	-	BOP

III. REMARKS

1. The safety-related dampers which receive an automatic signal to reposition after an accident (CRVIS, FBVIS, or SIS) are provided with Class 1E position indication in the control room. The Callaway design meets all of the stated recommendations.

TABLE 7A-3 (Sheet 55)

DATA SHEET 16.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.11.1	Status of Standby Power Sources Important to Safety	Voltages, currents	2[11]	To indicate system status

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.11.1	Status of Standby Power								
	4160 V Class 1E Incoming Current								
	Current	0-2000A	CT-NB0109	Y	RL015	N	-	-	BOP
	Current	0-2000A	CT-NB0111	Y	RL015	N	-	-	BOP
	Current	0-2000A	CT-NB0212	Y	RL015	N	-	-	BOP
	Current	0-2000A	CT-NB0209	Y	RL015	N	-	-	BOP
	Current	0-1200A	CT-PA0201	N	RL016	N	-	-	BOP
	4160 V Class 1E Bus Voltage								
	Voltage	0-5250 V	PT-101/B	Y	RL015	Y	-	-	BOP
	Voltage	0-5250 V	PT-201/B	Y	RL015	Y	-	-	BOP
	Diesel Gen No. 1								
	Current	0-1500A	CT-NE107	Y	RL015	N	-	-	BOP
	Voltage	0-5250 V	PT-NE107	Y	RL015	N	-	-	-
	KW	0-8MW	CT/PT-NE107	Y	RL015	N	-	-	BOP
	Vars	0-8Mvar	CT/PT-NE107	Y	RL015	N	-	-	BOP
	Frequency	55-65 Hertz	PT-NE107	Y	RL015	N		-	BOP
	Diesel Gen No. 2								
	Current	0-1500A	CT-NE106	Y	RL015	N	-	-	BOP
	Voltage	0-5250 V	PT-NE106	Y	RL015	N	-	-	BOP
	KW	0-8MW	CT/PT-NE106	Y	RL015	N	-	-	BOP
	Vars	0-8MVar	CT/PT-NE106	Y	RL015	N	-	-	BOP
	Frequency	55-65 Hertz	PT-NE106	Y	RL015	N	-	-	BOP

TABLE 7A-3 (Sheet 56)

DATA SHEET 16.1 (Continued)

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER IDENT.NO.	SENSOR/TRANSMITTER CL.1E	CONTROL ROOM INDICATOR PANEL	CONTROL ROOM INDICATOR CL.1E	CONTROL ROOM RECORDER PANEL	CONTROL ROOM RECORDER CL.1E	ERFIS COMPUTER
	Current to Class 1E 480 V System								
	Current	0-300A	CT-NB0110	Y	RL015	N	-	-	BOP
	Current	0-300A	CT-NB0113	Y	RL015	N	-	-	BOP
	Current	0-300A	CT-NB0210	Y	RL015	N	-	-	BOP
	Current	0-300A	CT-NB0213	Y	RL015	N	-	-	BOP
	Current	0-300A	CT-NB0117	Y	RL015	N	-	-	BOP
	Current	0-300A	CT-NB0217	Y	RL015	N	-	-	BOP
	Current	0-100A	CT-NB0116	Y	RL015	N	-	-	BOP
	Current	0-100A	CT-NB0216	Y	RL015	N	-	-	BOP
	Class 1E 125 V DC System					All Panel 16			
	Current Battery	(-)800 to (+)800A	Shunt-NK11	Y		Y	-	-	BOP
	Current Battery	(-)800 to (+)800A	Shunt-NK12	Y		Y	-	-	BOP
	Current Battery	(-)800 to (+)800A	Shunt-NK13	Y		Y	-	-	BOP
	Current Battery	(-)800 to (+)800A	Shunt-NK14	Y		Y	-	-	BOP
	Current Battery Charger	0-500A	Shunt-NK21	Y		Y	-	-	BOP
	Current Battery Charger	0-500A	Shunt-NK22	Y		Y	-	-	BOP
	Current Battery Charger	0-500A	Shunt-NK23	Y		Y	-	-	BOP
	Current Battery Charger	0-500A	Shunt-NK24	Y		Y	-	-	BOP
	Voltage	0-150V	Batt Mon-NK11	Y		Y	-	-	BOP
	Voltage	0-150V	Batt Mon-NK12	Y		Y	-	-	BOP
	Voltage	0-150V	Batt Mon-NK13	Y		Y	-	-	BOP
	Voltage	0-150V	Batt Mon-NK14	Y		Y	-	-	BOP

III. REMARKS

1. The Callaway design meets all of the stated recommendations. All Class 1E buses are provided with voltage and current indications.

TABLE 7A-3 (Sheet 57)

DATA SHEET 16.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
D.11.1	Status of Energy Sources Important to Safety (hydraulic, pneumatic)	Pressures	2^{11}	To indicate system status

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
D.11.1	Air Accumulator Tank Pressures								
	AFW Control	0-800 psig	PT-108	N	-	-	-	-	BOP
	Valves and	0-800 psig	PT-110	N	-	-	-	-	BOP
	Secondary Side	0-800 psig	PT-112	N	-	-	-	-	BOP
	Atmospheric Relief Valves	0-800 psig	PT-114	N	-	-	-	-	BOP

III. REMARKS

1. The safety-related air accumulators are described in Section 9.3.1 and shown on Figure 9.3-1, Sheet 5. The Callaway design meets all of the stated requirements.

TABLE 7A-3 (Sheet 58)

DATA SHEET 17.1

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.4.1	Radiation Exposure Meters (continuous indication at fixed locations)	Range, location, and qualification criteria to be developed to satisfy NUREG-0654, Section II.H.5.b and 6.b for emergency radiological monitoring	3	Verification of significant release and local magnitudes

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
	(Unnecessary Variable)								

III. REMARKS

This variable has been deleted from Regulatory Guide 1.97 in Revision 3.

TABLE 7A-3 (Sheet 59)

DATA SHEET 17.2

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.4.2	Airborne Radiohalogens and Particulates (portable sampling with onsite analysis capability)	10^{-9} to 10^{-3} μCi/cc	3[14]	Release assessment; analysis

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
	See Remarks Section								

III. REMARKS

Radiation protection air sampling and analysis equipment will be available on site for the monitoring and assessment of airborne radioactivity concentrations. Airborne sampling capabilities for particulates and radioiodines will be provided by low flow air samplers using glass fiber filters and TEDA-impregnated activated charcoal or silver Zeolite cartridges (accident conditions). Analysis of collection media will be performed by germanium gamma ray spectroscopy equipment (multichannel analyzer and HPGe detector. In the control building count room (auxiliary warehouse laboratory for Wolf Creek), utilization of laboratory gamma spectroscopy equipment will ensure the capability to analyze samples within the detection limits of 10^{-9} μCi to 10^{-3} μCi for principal gamma emitters.

TABLE 7A-3 (Sheet 60)

DATA SHEET 17.3

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.4.3	Plant and Environs	10^{-3} to 10^{-4} R/hr photons	3[15]	Release assessment; analysis
	Radiation (portable instrumentation)	10^{-3} to 10^{4} rads/hr beta radiations and low-energy photons	3[15]	

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER IDENT.NO.	SENSOR/TRANSMITTER CL.1E	CONTROL ROOM INDICATOR PANEL	CONTROL ROOM INDICATOR CL.1E	CONTROL ROOM RECORDER PANEL	CONTROL ROOM RECORDER CL.1E	ERFIS COMPUTER
	See Remarks Section								

III. REMARKS

In accordance with Regulatory Guide 1.97 recommendation, portable radiation survey instrumentation with the capability to detect gamma radiation over the range of 10^{-3} to 10^{4} R/hr will be maintained in the radiation protection instrument inventory. The capability to measure beta radiation fields over the range of 10^{-3} to 10^{4} R/hr will be provided by portable survey instrumentation equipped with beta-sensitive detectors.

TABLE 7A-3 (Sheet 61)

DATA SHEET 17.4

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.4.4	Plant and Environs Radioactivity (portable instrumentation)	Multichannel gamma-ray spectrometer	3	Release assessment; analysis

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				ERFIS COMPUTER
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
	See Remarks Section	0-5E5 cpm beta-gamma							

III. REMARKS

Portable, battery powered count rate meters equipped with a G-M pancacke detector will be used to gross count the total activity in field collected air samples. The gross activity will then be apportioned to specific isotopes using ratios derived from conservative accident analysis activity release calculations performed for each core reload. The proportioned isotopic activity will be used for the projected dose calculations until actual laboratory analysis may be obtained for the applicable field samples.

TABLE 7A-3 (Sheet 62)

DATA SHEET 17.5

I. REGULATORY GUIDE 1.97 TABLE 2 RECOMMENDATIONS

VARIABLE IDENT. NO.	VARIABLE	RANGE	CATEGORY	PURPOSE
E.5.1	Wind Direction	0 to 360 degrees (±5 degrees accuracy with a deflection of 15 degrees). Starting speed 0.45 mps (1.0 mph). Damping ratio between 0.4 and 0.6, distance constant ≤ 2 meters	3	Release assessment
E.5.2	Wind Speed	0 to 30 mps (67 mph) ±0.22 mps (0.5 mph) accuracy for wind speeds less than 11 mps (24 mph) with a starting threshold of less than 0.45 mps (1.0 mph)	3	Release assessment
E.5.3	Estimation of Atmospheric Stability	Base on vertical temperature difference from primary system, -5°C to 10°C (-9°F to 18°F) and ±0.15°C accuracy per 50-meter intervals (±0.3°F accuracy per 164-foot intervals) or analogous range for alternative stability estimates	3	Release assessment

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				PLANT PROCESS COMPUTER (PPC)
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
E.5.1	Wind Direction	0-360 degrees, ± 3 degrees	RD-ZT-50010A & B RD-SY-5060A & B	N	-	-	-	-	PPC
E.5.2	Wind Speed	0-100 mph ±1% or 0.15 mph Starting threshold = 0.6 mph	RD-ST-5010A & B RD-ST-5060A & B	N	-	-	-	-	PPC
E.5.3	Estimate of Atmospheric Stability Temperature	-50 to 50°C, ±0.1°C	RD-TE-5010A & B RD-TE-5060A & B	N	-	-	-	-	PPC

TABLE 7A-3 (Sheet 63)

DATA SHEET 17.5 (Continued)

III. REMARKS (Continued)

II. CALLAWAY PLANT DESIGN PROVISIONS

VARIABLE INDENT. NO.	VARIABLE	RANGE	SENSOR/TRANSMITTER		CONTROL ROOM				PLANT PROCESS COMPUTER (PPC)
					INDICATOR		RECORDER		
			IDENT.NO.	CL.1E	PANEL	CL.1E	PANEL	CL.1E	
	Temperature Difference	-50 to 50°C, ±0.05°C	RD-TE-5010A & 60A RD-TE-5010B & 60B	N	-	-	-	-	PPC
	Relative Humidity	0 - 100%, ±3%	RD-AE-5010 RD-AE-5060	N	-	-	-	-	PPC
	Precipitation Ground Level	0-1 inch, ±1%	RD-QE-5002	N	-	-	-	-	PPC

III. REMARKS

1. The Callaway design meets all of the stated recommendations.

2. The meteorological information system (site related) provides inputs to the PPC via the meteorological monitoring system at the met tower.

3. The parameters are sampled at a frequency of 1 minute or less by the PPC.

(Sheet 64)

Notes to Table 7A-3

Footnotes to Regulatory Guide 1.97 Table 2 - PWR Variables

[1]Where a variable is listed for more than one purpose, the instrumentation requirements may be integrated and only one measurement provided.

[2]The maximum value may be revised upward to satisfy ATWS requirements.

[3]A minimum of four measurements per quadrant is required for operation. Sufficient number should be installed to account for attrition. (Replacement instrumentation should meet the 2300°F range provision.)

[4]Design pressure is that value corresponding to ASME code values that are obtained at or below code-allowables values for material design stress.

[5]Sampling or monitoring of radioactive liquids and gases should be performed in a manner that ensures procurement of representative samples. For gases, the criteria of ANSI N13.1 should be applied. For liquids, provisions should be made for sampling from well-mixed turbulent zones, and sampling lines should be designed to minimize plateout or deposition. For safe and convenient sampling, the provisions should include:

a. Shielding to maintain radiation doses ALARA

b. Sample containers with container-sampling port connector compatibility

c. Capability of sampling under primary system pressure and negative pressures

d. Handling and transport capability

e. Prearrangement for analysis and interpretation

[6]Minimum of two monitors at widely separated locations.

[7]Detectors should respond to gamma radiation photons within any energy range from 60 keV to 3 MeV with an energy response accuracy of ±20 percent at any specific photon energy from 0.1 MeV to 3 MeV. Overall system accuracy should be within a factor of two over the entire range.

[8]Monitors should be capable of detecting and measuring radioactive gaseous effluent concentrations with compositions ranging from fresh equilibrium noble gas fission product mixtures to 10-day-old mixtures, with overall system accuracies within a factor of

(Sheet 65)

two. Effluent concentrations may be expressed in terms of Xe-133 equivalents or in terms of any noble gas nuclide(s). It is not expected that a single monitoring device will have sufficient range to encompass the entire range provided in this regulatory guide and that multiple components or systems will be needed. Existing equipment may be used to monitor any portion of the stated range within the equipment design rating.

[9]Provisions should be made to monitor all identified pathways for release of gaseous radioactive materials to the environs in conformance with General Design Criterion 64. Monitoring of individual effluent streams is only required where such streams are released directly into the environment. If two or more streams are combined prior to release from a common discharge point, monitoring of the combined stream is considered to meet the intent of the regulatory guide, provided such monitoring has a range adequate to measure worst-case releases.

[10]Design flow is the maximum flow anticipated in normal operation.

[11]Status indication of all standby power ac buses, dc buses, inverter output buses, and pneumatic supplies.

[12]Effluent monitors for PWR steam safety valve discharges and atmospheric steam dump valve discharges should be capable of approximately linear response to gamma radiation photons with energies from approximately 0.5 MeV to 3 MeV. Overall system accuracy should be within a factor of two. Calibration sources should fall within the range of approximately 0.5 MeV to 1.5 MeV (e.g., CS-137, Mn-54, Na-22, and Co-60). Effluent concentrations should be expressed in terms of any gamma-emitting noble gas nuclide within the specified energy range. Calculational methods should be provided for estimating concurrent releases of low-energy noble gases that cannot be detected or measured by the methods or techniques employed for monitoring.

[13]To provide information regarding release of radioactive halogens and particulates. Continuous collection of representative samples followed by onsite laboratory measurements of samples for radiohalogens and particulates. The design envelope for shielding, handling, and analytical purposes should assume 30 minutes of integrated sampling time at sampler design flow, an average concentration of 10^2 μCi/cc of particulate radioiodines and particulates other than radioiodines, and an average gamma photon energy of 0.5 MeV per disintegration.

[14]For estimating release rates of radioactive materials released during an accident.

[15]To monitor radiation and airborne radioactivity concentrations in many areas throughout the facility and the site environs where it is impractical to install stationary monitors capable of covering both normal and accident levels.

(Sheet 66)

[16]Guidance on meteorological measurements is being developed in a Proposed Revision 1 to Regulatory Guide 1.23, "Meteorological Programs in Support of Nuclear Power Plants."

[17]The time for taking and analyzing samples should be 3 hours or less from the time the decision is made to sample, except for chloride which should be within 24 hours.

[18]An installed capability should be provided for obtaining containment sump, ECCS pump room sumps, and other similar auxiliary building sump liquid samples.

[19]Applies only to primary coolant, not to sump.