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PLANT INSTRUMENTATION AND CONTROL SYSTEMS

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SECTION 7 PLANT INSTRUMENTATION AND CONTROL SYSTEMS

7.1 SUMMARY DESCRIPTION

This section presents the various plant instrumentation and control systems with discussion focusing on the design bases, system descriptions, and system evaluation. It is shown that the intent of the applicable criteria and codes at the time of construction, such as the GDCs referenced in Sections 1.2 and 1.5 and IEEE-279 (Reference 2), recognized 99182
by regulatory agencies (principally the NRC) concerned with the safe generation of nuclear power are reasonably met and that there is reasonable assurance that these systems will facilitate the production of power in a manner that insures no undue risk to the health and safety of the public.

In general the quality assurance procedures for original equipment fabrication, shipment, field storage, field installation and system component/checkout and records, pertaining to each of these, were consistent with the quality assurance requirements of the FSAR Chapter 13 (later changed to the Operational Quality Assurance Program (OQAP)). Equipment was receipt inspected and stored by NSP in accordance with the receipt inspection procedure. Installation was in accordance with the applicable procedures. System component checks were made in accordance with written procedures which cover calibration of electrical test instruments, drawing control, acceptance testing, equipment calibration, wire checking and functional testing. These actions were documented.

These instrumentation and control systems were subdivided for design and presentation purposes along the lines that represent the common division of these systems in existing facilities which adhere to the accepted practice of control and protection separation.

Section 7.2, Regulating Systems, describes how the reactor responds to plant power requirements in a stable, reliable, and safe manner. These systems ensure that plant startup, shutdown, and power operational load changes occur without plant parameters exceeding the control domain and entering the domain which requires the functioning of the Protection System or the Engineered Safety Features Instrumentation.

Section 7.3, Nuclear Instrumentation, describes the techniques utilized primarily for reactor protection, for monitoring neutron flux and generating appropriate trip and alarm functions for various phases of reactor operating and shutdown conditions.

Section 7.4, Plant Protection Systems, presents those features which act to limit the consequences of faults of moderate frequency, such as loss of feedwater flow, with the plant capable of returning to operation after corrective action. The Plant Protection System features provide a safety margin in which moderate frequency conditions developed can be resolved without more severe conditions developing. The systems are designed to permit periodic on-line testing to demonstrate the operability of the reactor protection system.

The generation of the tripping functions necessary to actuate the Engineered Safety Features are also discussed in Section 7.4. Engineered Safety Features Instrumentation presents those features which act to limit the consequences of potentially severe (infrequent) faults such as a loss of reactor coolant from a small rupture which exceeds normal charging system makeup and requires actuation of the safety injection system. The Engineered Safety Features Instrumentation also acts to mitigate failures that have the potential for significant release of radioactive material and extended plant outage.

Section 7.5, Plant Radiation Monitoring System, presents those features which provide information on potential radiological health hazards, resulting from plant malfunctions for the purpose of preventing or minimizing the effects of an inadvertent release of radioactivity to the environment.

Section 7.6, Incore Instrumentation, presents a system designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. The information obtained from the incore instrumentation system can be used to confirm the reactor core design parameters and calculated hot channel factors. The system performs no operational plant control function.

Section 7.7, Process Computer, discusses the digital computer system installed for each unit. This computer system performs on-line calculations for monitoring the operation and performance of the plant.

Section 7.8, Operating Control Station, discusses the control room controls and instrumentation necessary for safe operation of the plant, including the reactor and the turbine generator, under normal and accident conditions. Process variables which are required on a continuous basis for the startup, power operation and shutdown of the plant are indicated, recorded, and/or controlled from a controlled access area.

Section 7.9 Seismic Design, Testing and Monitoring discusses the seismic design and testing criteria and qualification for the reactor protection and engineered safety features components. Features of the seismic monitoring system are also discussed.

Section 7.10 Post Accident Monitoring Instrumentation, discusses the requirements for instruments that are required to operate during and following an accident. The operability of the monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident.

Section 7.11, ATWS Mitigating System Actuation Circuitry/Diverse Scram System, discusses the AMSAC/DSS system installed for Prairie Island Unit 1 and Unit 2. This system trips the turbine and starts AFW in addition to inserting the Control Rods in response to ATWS conditions.

In summary, the information presented in this section is intended to provide assurance that the plant instrumentation and control system have been designed, constructed, tested, and will be operated in accordance with their intended functions.

7.2 REGULATING SYSTEMS

7.2.1 Design Basis

The reactor automatic control system is designed to reduce transients for the design load perturbations, so that reactor trips will not occur for these load changes.

Overall reactivity control is achieved by the combination of chemical shim and Rod Control Cluster (RCC) assemblies. Long-term regulation of core reactivity is accomplished by adjusting the concentration of boric acid in the reactor coolant (chemical shim). Short-term reactivity control for power changes or reactor trip is accomplished by moving RCC assemblies. 00-274

The function of the Reactor Control System is to provide automatic control of core reactivity by movement of the RCC assemblies during power operation of the reactor. The system uses input signals including neutron flux; coolant temperature and turbine load. The Chemical and Volume Control System (Section 10.2.3) supplements the reactor control system by the addition and removal of varying amounts of boric acid solution to return the RCC assemblies to a desired operating position for an evenly distributed axial power distribution. 00-274 00-274

When the reactor is critical, the best indications of reactivity status change in the core are a change in the position of the control group or average coolant temperature in relation to turbine power. Any unexpected change in the position of the control group 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 to the above mentioned indication, there is provision for direct indication of reactor coolant boron concentration. Also periodic samples of coolant boron concentration are taken. The variation in concentration over core life provides a further check on the reactivity status of the reactor including core depletion as compared to the core design. 00-274

The Reactor Control System is designed to enable the reactor to follow unplanned load changes automatically when the plant output is above approximately 15% of nominal power. Control rod positioning may be performed automatically when plant output is above this value, and manually at any time. 00-274

The control system enables the nuclear plant to accept a step load change of 10% and a ramp load change of 5% per minute within the load range of 15% to 100% without reactor trip, subject to possible xenon limitations. The steam dump system and automatic rod control permits the plant to accept a 47.5% nominal full load rejection without reactor trip. 01-076

The control system is designed to restore coolant average temperature to within the programmed temperature limits, following any of the above changes in load. After the plant has stabilized, the operator must adjust the chemical shim and control rods to return axial power distribution (ΔI) to the target band as defined by the Technical Specifications. 00-274 The operating goal is to return ΔI as close as is practicable to an assigned target value within the target band to assure the most stable operation. (Ref. 74)

The maximum allowable rod insertion for any given power level is based upon the nuclear design of the core fuel load. This direct relationship between control rod position and reactor power distribution establishes the lower insertion limit. There are two ERCS driven alarm setpoints to provide warning to take corrective action in the event a control group 00-274 approaches or reaches its lower limit. See section 7.2.2.2.2 for additional information.

Rod withdrawal stops and turbine runbacks based upon intermediate and power range nuclear flux and overpower ΔT and overtemperature ΔT channels are provided to prevent a reactor trip which could result from control rod withdrawal initiated by a malfunction of the reactor control system or by operator action.

The pressurizer water level is programmed to be a function of the auctioneered high 00-274 coolant average temperature. This is to minimize the requirements on the Chemical and Volume Control and Waste Disposal System resulting from coolant density changes during loading and unloading from full power to zero power.

Following a reactor and turbine trip, sensible heat stored in the reactor coolant and decay 00-274 heat in the core is removed without actuating the steam generator safety valves by means of a steam dump system. Reactor Coolant System temperature is reduced to the no load condition. This no load coolant temperature is maintained by the steam dump system.

The Control System provides operation as a stable system over the full range of automatic control throughout core life without requiring routine operator adjustments of set points.

7.2.2 <u>Description</u>

The Power Regulating System can be broken down into subsystems as follows:

a. Rod Control System

1. Rod Drive Programmer

a) Full Length Rod Control 00-274

2. Rod Position Indication

a) Individual (Actual rod position)

b) Bank (Demand rod position)

b. Steam Dump Control

c. Feedwater Control

d. Pressure Control

e. Pressurizer Level Control

f. Automatic Turbine Load Runback

A simplified block diagram of the Reactor Control System is shown in Figure 7.2-1.

7.2.2.1 Rod Control

There are 29 total Rod Control Cluster (RCC) assemblies. RCC assemblies are divided into: (a) Two shutdown banks with 4 assemblies in each bank; (b) four control banks containing 8, 4, 5 and 4 assemblies respectively. Figure 7.2-2 shows the location of the full length RCC assemblies in the core. The four control banks are the only rods that can be manipulated under automatic control. Some banks are divided into groups to obtain smaller incremental reactivity changes. All RCC assemblies in a group are electrically paralleled to step simultaneously. 00-274

The drive mechanisms used in conjunction with RCC assemblies are capable of permitting free fall of the assemblies.

The automatic rod control system maintains the coolant average temperature by adjusting the RCC assembly positions.

The Reactor Control System is capable of restoring programmed average temperature following a change in load. The coolant average temperature increases linearly from zero power to full power.

00-274

The coolant temperatures are measured by the hot and cold leg bypass loop Resistance Temperature Detectors. These temperature measurements are averaged for each loop. The highest of the four measured average temperatures is the control signal. This signal is sent to the T_{avg} controller through a lead/lag compensation unit where it is compared with the reference temperature set by the turbine power. This controller commands the direction and speed of control group rod motion. A power load mismatch signal is also employed as a control signal to improve the plant performance. The power load mismatch compensation serves to speed up system response and to reduce transient peaks.

The control RCC assemblies are divided into four banks with 1 or 2 groups per bank. Each group in a bank is driven by the same variable speed rod drive control unit which moves the groups sequentially one step at a time. The sequence of motion is reversible; that is, a withdrawal sequence is the reverse of the insertion sequence. The variable speed sequential rod control affords the ability to insert a small amount of reactivity at low speed to accomplish fine control of reactor coolant average temperature about a small temperature deadband.

Manual control is provided to move a control bank in or out at a pre-selected fixed speed.

Proper sequencing of the RCC assemblies is assured by fixed programming equipment in the Rod Control System. Startup of the plant is accomplished by first manually withdrawing the shutdown rods to the full out position. This action requires that the operator select the SHUTDOWN BANK position on a control board mounted selector switch and then position the IN-HOLD-OUT lever (which is spring return to the HOLD position) to the OUT position.

The control banks are then withdrawn manually by the operator by first selecting the MANUAL position on the control board mounted selector switch and then positioning the IN-HOLD-OUT lever to the OUT position. In the MANUAL selector switch position, the rods are withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

The RCC assemblies are manually adjusted to control axial power distribution as power is changed (Ref. 74). Boron concentration is changed to compensate for any additional core 274
reactivity changes which are not compensated for by the RCC assemblies. Boron concentration is also changed to compensate for fuel depletion and xenon changes.

When the reactor power reaches approximately 15%, the operator may select the AUTOMATIC position, which bypasses the IN-HOLD-OUT lever, and gives rod motion control to the Reactor Control System. An interlock blocks automatic rod withdrawal when turbine impulse pressure is less than 15% power. In the AUTOMATIC position, the rods are again withdrawn (or inserted) in a predetermined programmed sequence by the automatic programming equipment.

Programming is set so that as the first bank out reaches a preset position above the centerline of the core, the second bank begins to move out simultaneously with the first bank. This staggered withdrawal sequence continues until the plant reaches the desired power level. The programmed staggered insertion sequence is the opposite of the withdrawal sequence, i.e., the last control bank out is the first control bank in.

With the simplicity of the rod program, the minimal amount of operator action, and two separate position indications available to the operator, there is very little possibility that rearrangement of the control rod sequencing could occur. A further description of the full length rod control system is presented in Reference 11.

7.2.2.1.1 Shutdown Groups Control

The shutdown groups, together with the control groups, are capable of shutting the reactor down. They are used in conjunction with the adjustment of chemical shim and the control groups to provide a shutdown margin of at least one percent following reactor trip with the most reactive control rod in the fully withdrawn position.

The shutdown groups can only be controlled manually and are withdrawn at a constant speed. Any reactor trip signal causes them to fall into the core. They are fully withdrawn during power operation and are withdrawn first during startup. Criticality is approached with the control groups after withdrawal of the shutdown groups.

7.2.2.1.2 Control Rod Misalignment

A number of situations may be postulated with control rods or groups of shutdown rods significantly inserted at full power which would violate design limits. Some may be postulated which would violate the safety limits. There are no interlocks provided to prevent control rods or groups of shutdown rods from being inserted during operation.

The basis for the design rests on administrative control of the control rods and by supplying the operator with information from a variety of sources. Administrative control is stipulated in the technical specifications by control rod insertion limits which require the shutdown groups to be out at full power. The Rod Position Indication System provides the operator with continuous indication of rod positions. The technical specifications require the operator to verify rod positions should the indication system not be fully operable. Inserted control rods or shutdown groups could possibly be detected by other available systems. The axial offset, and in the case of asymmetric rod insertions the radial tilt, provide indication to the operator of an anomaly such as mispositioned control groups or shutdown groups.

Shutdown rods are withdrawn prior to criticality so that the sequence of withdrawal is not significant to safety. The required sequence of the final control groups is specified in the Core Operating Limits Report (COLR) and is programmed when the automatic or manual mode is selected. The program is not used when in bank select mode. 00-274

7.2.2.1.3 Rod Withdrawal Stops

Rod withdrawal stops are utilized to preclude the need for a reactor trip or prevent an abnormal condition from increasing in magnitude and causing a reactor trip.

The list of rod stops is given below.

	Rod Stop	Actuation Signal	Rod Motion to be blocked
1.	Nuclear Overpower	1/4 high power range neutron flux or 1/2 high intermediate range neutron flux	Automatic and Manual Withdrawal
2.	High ΔT	2/4 overpower ΔT or 2/4 over temperature ΔT (initiation turbine load rejection)	Automatic and Manual Withdrawal
3.	Low Power (P2)	Low MWe load signal (below 15%) for low turbine impulse pressure	Automatic Withdrawal
4.	High Bank D Rod Position*	Control Bank D reaches 220 steps withdrawn from the core	Automatic Withdrawal

* This rod stop is identified for completeness only. It is considered an administrative rod stop only.

7.2.2.1.4 Full Length RCC Assembly Position Indication

Two separate systems are provided to sense and display control rod position as described below:

a. Individual Rod Position Indication (IRPI) System - An analog signal of actual position is produced for each RCC assembly by a position transmitter. The output of the IRPI is a meter in the control room and also a signal to the ERCS.

   An electrical coil stack linear variable differential transformer is placed above the stepping mechanisms of the control rod magnetic jacks external to the pressure housing. When the associated control rod is at the bottom of the core, the magnetic coupling between primary and secondary windings is small and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is derived.

   Direct, continuous readout of every RCC assembly position is presented to the operator by individual meter indications, without need for operator action to determine rod position.

Rod Bottom Lights - The IRPI coil stacks also produce a rod bottom signal when the associated control rod is at the bottom of the core. Lights are provided for rod bottom positions for each rod. The lights are operated by bistable devices in the analog system. The output is a light for each rod below its IRPI meter informing the operator the rod is below 20 steps withdrawn.

Search Coils - The search coils are an extra coil located at the bottom of the IRPI stack. These coils are not physically connected to the IRPI system, but could be placed in service under certain conditions. When connected to appropriate instruments, the search coils would check for a rod bottom condition.

b. Group Position Indication (Group Demand Counter) - This system counts pulses generated in the rod drive control system. One counter is associated with each group of RCC assemblies. Readout of the digital system is in the form of add-subtract counters reading the number of steps of rod withdrawal (demand position) with one display for each group. These readouts are mounted on the control panel. Counters also provide an audible signal of rod motion as an operator aid.

The group position and individual rod position systems are separate systems; each serves as backup for the other. Operating procedures require the reactor operator to compare the group and individual readings upon receiving a rod deviation alarm. Therefore, a single failure in rod position indication does not in itself lead the operator to take erroneous action in the operation of the reactor. A detailed description of the control rod drive power supply is presented in Reference 11.

The rod position indicator channel is sufficiently accurate to detect a rod ±7.5 inches away from its demand position in the center region of the core. A misalignment less than 15 inches in the center region of the core does not lead to over-limit power peaking factors. In the peripheral core regions (less than or equal to 30 steps or greater than or equal to 215 steps) a misalignment less than 22.5 inches will not lead to over-limit power peaking factors due to small control rod reactivity worth in this region of the core.

If one or more rod position indicator channels should be out of service, detailed operating instructions shall be followed to assure the alignment of the non-indicated assemblies.

These operating instructions require use of the moveable incore detector system at prescribed time intervals and following significant motion of the non-indicated assemblies.

7.2.2.2 Control Rod Monitoring Systems

7.2.2.2.1 Rod Deviation Monitoring System

The demanded group position and individual rod position signals are displayed on the control board. They are also monitored by the plant computer. Whenever an individual rod position signal deviates from the bank demand signal by more than 12 steps from the group demand counter, when the demand counter is between 30 and 215 or by 24 steps when the demand counter is less than 30 or greater than 215, an audible computer alarm 00-274
and a visual printout as to which rod is misaligned is provided. The rod deviation comparator is designed so that the alarm is actuated before rod deviation, which would allow the core design hot channel factors to be exceeded, with appropriate allowance for instrument error. Actual position information is displayed on the control board as well as being monitored by the plant computer. 00-274

Safety is not adversely affected if the rod deviation monitoring system is inoperative because of unavailability of the plant computer or otherwise. The means of detecting rod deviation is available from the Rod Position Monitoring System. 00-274

The control board position indicator gives the plant operator the actual position of the rod in steps. The indicators are grouped by banks (e.g., Control Bank A, Control Bank B) 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. Requirements for logging of rod positions, in the event that the rod position deviation monitor is inoperable are presented in the Technical Specifications.

It is noted that misaligned Rod Control Cluster Assemblies are also detected by asymmetric power distribution as seen in the excore neutron detectors or the moveable incore detector system.

As discussed in detail in WCAP-7669 "Topical Report, Nuclear Instrumentation System," (Reference 12), isolated signals derived from the out of core neutron detectors 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 indicators, the operator can determine the deviating control rod and take corrective action.

7.2.2.2.2 Control Bank Rod Insertion Monitor

The rod insertion limits are administratively controlled and are alarmed by the rod insertion limit function on ERCS. In the event the program or ERCS is inoperable, rod insertion limits are administratively controlled by operating procedures. There are two control board alarms to provide warning to take corrective action in the event a control group approaches its insertion limit. One alarm is the low-low limit. The other alarm is the low limit which is set approximately 20 steps above the low-low limit.

Rod insertion limits were initially established by: 00-274 00-265

a. Establishing the allowed rod reactivity insertion at full power consistent with purposes given below.

b. Establishing the differential reactivity worth of the control rods when moved in normal sequence.

c. Establishing the change in reactivity with power level and, 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.

The rod insertion limits are re-evaluated as part of the Core Reload Safety Evaluation for each recycled core. The established limits are part of the initial assumptions for the Reload Safety Evaluation. Maintaining the rods above their insertion limits is necessary for the reactor to be bounded by the Reload Safety Evaluation transient and accident analysis. All key nuclear parameters of the reload core are measured as part of the initial and periodic physics testing program. This will ensure that the reload core is bounded by the Reload Safety Evaluation. 00-265

The established rod insertion limits for each unit are contained in the Core Operating Limits Report (COLR). 00-274

The purpose of the control bank rod insertion monitor is to give warning to the operator of a decrease in shutdown margin. In addition, the insertion monitor provides a limit on the maximum inserted rod worth in the unlikely event of a hypothetical rod ejection, and limits rod insertion such that acceptable nuclear peaking factors are maintained. Since the amount of shutdown reactivity required for the design shutdown margin following a reactor trip increases with increasing power, the allowable rod insertion limits must be decreased (the rods must be withdrawn further) with increasing power. The ΔT between the hot leg and cold leg, which is a direct function of power, is an input to the insertion monitor. The rod insertion monitor calculation for each rod bank is as follows:

$Z_{LL} = A(\Delta T) + B$

where Z_{LL} = maximum permissible insertion limit for affected control bank

(ΔT) = Average ΔT for two loops (with two detector pairs per loop)

A,B = constants chosen to maintain $Z_{LL} \geq$ actual limit in the COLR. 00-274 00-265

The actual control rod bank position (Z) is compared to Z_{LL} as follows:

If $Z - Z_{LL} \leq D$ a low alarm is actuated

If $Z \leq Z_{LL}$ a low-low alarm is actuated

Actuation of the low or low-low alarm alerts the operator of an approach to a reduced shutdown reactivity situation. Administrative procedures require the operator to initiate boration with the Chemical and Volume Control System. The value for "D" is chosen to provide the operator with a warning that the limit is being approached. Figure 7.4-5 shows a schematic representation of the control bank rod insertion monitor. In addition, to the rod insertion monitor for the control banks, an ERCS alarm is provided to warn the operator if any shutdown bank leaves the fully withdrawn position. 00-274

The rod insertion limits serve the following purposes:

a. To assure trip effectiveness by assuring that only a limited fraction of the total rod worth is inserted into the core at full power. A larger insertion is allowed at part power because less rod worth is then required to provide reactor trip.

b. To assure that core hot channel factor limits are not exceeded at full power due to rod insertion. The peaking factor associated with the Control Rod Misalignment Analysis in general is based on Control Bank D rods being fully inserted to the insertion limit except one rod assembly being fully withdrawn. 00-265

c. To limit the potential consequences of a hypothetical rod ejection accident.

7.2.2.3 Steam Dump Control

The function of the Steam Dump Control System is to: 00-265

1. Permit the plant to accept a sudden large load decrease of up to 47.5% of nominal full load, when used in conjunction with control rods, without incurring a reactor trip. 00-265

2. Remove stored energy and residual heat following a reactor trip without actuation of the steam generator safety valves. 00-265

3. Permit a controlled cooldown to cold shutdown. 00-265

4. Maintain the plant in hot standby condition.

The four functions are implemented by means of two different modes of control:

- The T_{avg} Control mode - covers functions 1 and 2, is selected by placing the Steam Dump selector switch to the T_{avg} position. 65

- The Pressure Control mode - covers functions 3 and 4, is selected by placing the Steam Dump selector switch to the Steam Pressure position. (Reference 63)

See section 11.4 for Steam Dump valve capabilities.

7.2.2.3.1 T_{avg} Control Mode

This circuit prevents large increases in reactor coolant temperature following a large, sudden load decrease. This is accomplished by generation of an error signal. The error signal is generated by comparing a compensated T_{avg} signal with the T_{ref} signal. Following a sudden load decrease or a turbine trip, T_{ref} is immediately decreased and T_{avg} tends to increase, thus generating the error signal. The error signal creates a steam dump demand modulate signal in the load rejection steam dump controller. The T_{avg} signal and the T_{ref} signal are identical to those used in Rod Control System. 00-265

The five steam dump valves are separated into two groups, the condenser dump valve and the atmospheric dump valves. If the temperature error signal exceeds the HI setpoint, the first group (condenser dump valve) is tripped open. If the temperature error signal exceeds the HI-HI setpoint, the second group (atmospheric dump valves) are tripped open. If neither of these setpoints are exceeded, the valves are opened according to the modulate signal created from the temperature error signal. 00-265

After reduction of the error below each trip-open setpoint, the appropriate valves return to modulating control. Final restoration of the compensated T_{avg} signal to equilibrium with the T_{ref} signal, that is, returns to within the deadband, is accomplished with rod control. This completely closes all the dump valves. Normal operation occurs within a built in deadband between the two signals so that no error signal is developed. 00-265

7.2.2.3.1.1 Small Load Perturbations

To prevent actuation of steam dump on small load perturbations (e.g., less than the 10% step load decrease and the sustained ramp load decrease of 5%), an independent load rejection sensing circuit is provided. The circuit senses the rate of decrease in turbine load as detected by the turbine impulse chamber pressure, and provides an availability signal when the rate of load rejection exceeds a preset value. The availability signal provides air supply to the steam dump valves. 00-265

7.2.2.3.1.2 Turbine Trip Override

Following a turbine trip, as monitored by the turbine trip signal, the load rejection steam dump controller is defeated and the turbine trip steam dump controller becomes active. The error signal described in 7.2.2.3.1 is the same except that the trip signal has been set at the no-load reactor coolant average temperature. The steam dump is controlled by the signal out of the turbine trip steam dump controller which creates a steam dump demand signal proportional to the error signal. The error signal also determines whether a valve group is to be tripped open or modulated open. In either case, they are modulated after reduction of the error below the trip-open setpoint. 00-265

7.2.2.3.2 Pressure Control Mode

When starting up, shutting down, or holding the plant in a hot shutdown condition, the operator may switch to the main steam header pressure controller. This controller which has proportional, rate and reset action, maintains the steam header pressure at the adjustable pressure setpoint by automatic control of the steam dump valves. 00-265

If condenser vacuum is lost or both circulating water pumps are lost, the steam dump to the condenser valve is blocked.

7.2.2.4 Feedwater Control

The steam generators are equipped with a microprocessor based feedwater control system which maintains a programmed water level in each steam generator as a function of load on the secondary side of the steam generator. The system has two modes, Low Power and High Power, with an automatic transition between modes as necessary for plant operation. For a given steam generator, a signal to regulate the two parallel feedwater regulating valves, the main and the bypass, is generated (Figure 7.2-3) based on the following inputs:

- Wide Range Steam Generator Level (Low Power mode only)
- Narrow Range Steam Generator Level
- Feedwater Temperature
- Feedwater Supply Header Pressure
- Steam Generator Pressure
- Turbine Impulse Pressure
- Steam Flow (High Power mode only)
- Feedwater Flow (High Power mode only)

In order to ensure the overall reactor control system would maintain the control and load rejection capabilities verified by plant startup testing, the control system response was modeled and tested via computer simulation by the vendor. Key attributes of the modeled response were then used as acceptance criteria in plant operational tests for specific test perturbations. Meeting the test criteria ensured that original test conclusions regarding system capabilities were not invalidated.

Continued delivery of feedwater to the steam generators is required as a sink for the heat stored and generated in the reactor coolant following a reactor trip and turbine trip. Continued feedwater delivery is assumed by feedwater pump and/or auxiliary feedwater system. An override signal closes the main feedwater valves upon reactor trip when the coolant average temperature is below a given temperature or closes both valves (main and bypass) when the respective steam generator level rises to a given value (which initiates turbine trip) or upon safety injection signal. Manual override of the feedwater control systems is also provided.

Prolonged operation of the Steam Generator Level Control portion of the Reactor Control system in local or remote manual control is acceptable provided automatic safety signals will perform their intended functions. When in manual control, both the main and bypass Feedwater Regulating valves are required to close upon receipt of an SI or Hi-Hi Steam Generator level signal. Also, the main Feedwater Regulating valves are required to close upon receipt of a Reactor Trip signal coincident with a Low T_{avg} signal.

7.2.2.5 Pressure Control

The reactor coolant system pressure is maintained at a constant value by using either the heaters (in the water region) or the spray (in the steam region) of the pressurizer. The electrical immersion heaters are located near the bottom of the pressurizer. A portion of the heater groups are proportionally controlled to correct small pressure variations. These variations are due to heat losses, including heat losses due to a small continuous spray. The remaining (backup) heaters are turned on either when the pressurizer pressure controller signal is below a given value or when pressurizer level is above a given level.

The spray nozzles are located at the top of the pressurizer. The spray valves are opened when the pressure controller signal is above a given set point. The spray rate increases proportionally with increasing pressure 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.

Two power operated relief valves limit system pressure during large load reduction transients and must be fully open in 2.0 seconds or less. The design setpoint for PORV actuation is identified in Table 4.1-2.

Two spring loaded safety valves limit system pressure following a complete loss of load without assuming a direct reactor trip or turbine by-pass.

7.2.2.6 Pressurizer Level Control

A programmed pressurizer water level as a function of auctioneered average reactor coolant temperature is provided in conjunction with the programmed coolant temperature. This minimizes the demands upon the Chemical and Volume Control System and the Waste Disposal System imposed by coolant density changes during power increases and decreases. The pressurizer water level decreases as the load is reduced from full load. This is the 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 permit manual control of pressurizer level during startup and shutdown operations, the charging-pump speed can be manually regulated from the main control room.

7.2.2.7 Automatic Turbine Load Runback

A turbine load runback is initiated by an approach to overpower or overtemperature conditions. This will prevent high power operation, which might lead to minimum DNBR less than the applicable limit. See section 7.4.1.2.3.10 for details on development of overpower and overtemperature conditions.

The turbine load runback interlocks cause the turbine control logic to reduce turbine load via the reference counter at a rate of 200% per minute for 1.5 seconds followed by a 28.5 second pause (a 5% load reference decrease). During the pause, the reference counter is maintained at the runback count. If the condition causing the runback persists beyond the initial 30 second period, the interlock will initiate another 5% turbine load reference reduction.

The reduction in turbine load varies depending upon the turbine control mode and power level at the time the turbine runback occurred.

7.2.3 Performance Analysis

7.2.3.1 Plant Stability

The Rod Control System is designed to limit the amplitude and the frequency of continuous oscillation of coolant average temperature about the control system setpoint within acceptable values. Because stability is more difficult to maintain at low power under automatic control, automatic control is prevented below 15% of full power.

7.2.3.2 Step Load Changes Without Turbine Bypass

A typical automatic power control requirement is to restore equilibrium conditions, without a plant trip, following a plus or minus 10% step change in load demand, over the 15% to 100% power range, subject to possible xenon limitations. 01-076

The design must necessarily be based on conservative conditions and a greater transient capability than is expected for actual operating conditions.

The function of the control system is to avoid reactor trip through keeping the reactor coolant average temperature deviation during the transient within a given value and to restore average temperature to the programmed set point within a given time. Excessive pressurizer pressure variations are prevented by using spray and heaters in the pressurizer.

The margin between overtemperature ΔT setpoint and the measured ΔT is of primary concern for the step load changes. This margin is influenced by neutron flux, pressurizer pressure, reactor coolant average temperature, and temperature rise across the core.

7.2.3.3 Ramp Loading and Unloading

Ramp loading and unloading is provided under automatic or manual operator control. The function of the control system is to maintain the coolant average temperature and pressure within operating limits. Should a transient occur during manual load changes, rod control should be returned to automatic as soon as is practicable in order to meet design load change capabilities. Failure to return to automatic rod control, during a transient, will lead to a Reactor Protection System actuation. 00-274

Under automatic rod control the minimum control rod speed provides a sufficient reactivity rate to compensate for the reactivity changes resulting from the moderator and fuel temperature changes during nominal load changes. The speed is slow enough to provide minimal overshoot for correcting small temperature deviations, yet fast enough to limit excessive RCS temperature, RCS pressure, and secondary steam pressure deviations for 5% ramp rates thus ensuring a stable plant response. The ramp rate loading and unloading is limited to 5% per minute within the load range of 15% to 100% of nominal power, subject to possible xenon limitations. 01-076 00-265 01-076

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 heaters limit the resulting system pressure decrease. The pressurizer level is programmed such that the water level is above the setpoint at which the heaters cut out during the loading and unloading transient.

The primary concern for the loading rate is to limit the overshoot in coolant temperature so that a margin is provided for the overtemperature ΔT setpoint.

7.2.3.4 Loss of Load With Turbine Bypass

The system can accept a step load loss of up to 47.5% of nominal full load without actuating any reactor trip. The automatic steam dump system together with the rod control system is able to accommodate this load rejection and to reduce the effects of the transient imposed upon the reactor coolant system. The reactor power is reduced at a rate consistent with the capability of the rod control system. Reduction of the reactor power is automatic down to 15 percent of full power. Manual control must be used when the power is below this value. 01-030

The pressurizer relief valves might be actuated for the most adverse conditions, e.g., the most negative Doppler coefficient, minimum incremental rod worth and smallest moderator coefficient. The relieving capacity of the power operated relief valves is adequate to limit the system pressure to prevent an actuation of high pressure reactor trip for the above conditions.

7.2.3.5 Turbine Generator Trip With Reactor Trip

Whenever the turbine generator unit trips at an operating level above 10% power (P9), the reactor also trips. The plant is operated with a programmed average temperature as a function of load, with the full load average temperature significantly greater than the saturation temperature corresponding to the steam generator pressure at the safety valve set point. 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 steam temperature, a heat sink is required to remove heat stored in the reactor coolant to prevent actuation of steam generator safety valves for this trip from full power. The heat sink is provided by the combination of controlled steam generator PORV release, by the steam dump, and by makeup of cold feedwater to the steam generators.

The steam dump system is controlled from the average reactor coolant temperature signal whose set point values are reset upon trip to the no load value. Actuation of the steam dump is rapid to prevent actuation of the steam generator safety valves and steam generator PORV. A direct feedback of temperature acts to modulate the valves to minimize the total amount of steam which is bypassed.

Following the turbine trip, the steam voids in the steam generators will collapse and the feedwater regulating valves provide sufficient feedwater flow to restore water level in the downcomer. The feedwater flow is cut off when the coolant average temperature decreases below a given temperature value (or when the steam generator water level reaches a given high level). This later condition also initiates turbine trip.

Feedwater makeup is controlled manually to restore and maintain steam generator level while maintaining the reactor coolant temperature at the desired value. Residual heat removal is maintained by the steam dump pressure controller (manually selected) which controls the amount of steam dumped. This controller operates the same dump valves 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 level of pressurizer heater. But, if heaters become uncovered following the trip, the Chemical and Volume Control System will provide full charging flow to restore water level in the pressurizer. The low level letdown isolation function turns the heater off and isolates the letdown. After pressurizer level is recovered, heaters are turned on to restore pressurizer pressure to normal. The Safety Injection Pumps can also be used to perform this function.

Following the trip, the steam dump and feedwater control systems are designed to prevent the average coolant temperature from falling below the temperature required to ensure adequate reactivity shutdown margin.

7.3 NUCLEAR INSTRUMENTATION

7.3.1 Design Basis

Fission Process Monitors and Controls

GDC-13 Means shall be provided for monitoring or otherwise measuring and maintaining control over the fission process throughout core life under all conditions that can reasonably be anticipated to cause variations in reactivity of the core.

The design bases for the Nuclear Instrumentation, which is utilized; (1) for reactor protection and (2) for control functions, are discussed in Sections 2 and 5 of Reference 12.

7.3.2 Description

The detailed description of the Nuclear Instrumentation System is covered in Sections 3 and 5 of Reference 12.

7.3.3 Performance Analysis

See Sections 1 and 4 of Reference 12 for design evaluation considerations.

The redundant nuclear instrument channels are powered from the four separate instrument buses shown in Figures 8.5-1a, 8.5-1b, 8.5-2a and 8.5-2b. Loss of any one vital instrument bus will not cause a reactor trip in the power range, if the measured flux is greater than the P10 setpoint such that source and intermediate range Hi flux reactor trips are blocked.

The nuclear instrument channel bi-stable setpoint repeatability is within ± 1% of full power. This repeatability value includes errors due to non-linearity, hysteresis, repeatability and long-term drift. Setpoints also account for instrument uncertainties as defined by the PINGP setpoint methodology. 00259

7.3.4 Calibration of Excore Detectors To Incore Flux Measurements

A description of the tests and measurement requirements to obtain the necessary data required to calibrate the excore detectors to the incore distribution, and the excore detector calibration procedure with typical examples of operating plant data are presented in this section.

7.3.4.1 Tests and Measurements Requirements

The tests required during the startup program to obtain the data required to calibrate the excore detectors with the incore power distribution are listed below. When equilibrium conditions have been obtained, the formal data acquisition for the excore detector calibration is performed. Tests which are performed with a primary objective other than excore/incore calibration are also utilized. The data obtained during the following tests include full core moveable detector flux maps, excore detector response, and heat balance data.

7.3.4.2 Summary of Typical Test Conditions from Which Excore/Incore Calibration Data is Obtained

Power Level	Reactor Conditions	Rod Bank Configuration
Maximum Authorized Power	Equilibrium Xenon	Bank D 218 steps*
Maximum Authorized Power	Fuel Conditioned	As needed for -4% of target Delta I
Maximum Authorized Power	Fuel Conditioned	As needed for +4% of target Delta I

NOTE: Maximum Authorized Power is normally 100% unless a power derate is necessary for core peaking factors.

* Bank D rods are normally at 218 steps per plant procedures. Incore flux data will be adjusted by computer codes for actual rod position.

In addition to the above data, heat balance and excore detector response is obtained at various power levels throughout the startup program.

7.3.4.3 Excore Instrumentation Calibration

In this section the procedure is presented for the calibration of the reactor's core power f(ΔI) contribution to the overpower and overtemperature ΔT setpoints.

The calibration requires the use of excore detector data, plant heat balance data and incore moveable detector flux maps. The correlation's made between this data will be presented following a brief description of the system and the setpoints.

The power range circuit (Figure 7.3-1) incorporates the output current of the excore detectors into several functions. Reactor core thermal power level (as a percent of full power) is determined from the linear relationship of core power to the detector current sum for a particular channel, i.e., top and bottom detector. (In Figure 7.3-1, amplifier NM-310 provides a calibrated voltage proportional to the current sum.)

The power indication is used both operationally and in core protection. A reactor trip occurs when 2 of the 4 excore power indications exceeds the trip setpoint. This is called the Power Range High Neutron Flux Reactor trip. See section 7.4.1.2.3.2 for details.

The second major function of the excore detectors is to provide axial offset protection through the f(ΔI) contribution to the overpower and overtemperature ΔT setpoints. See section 7.4.1.2.3.8 and 7.4.1.2.3.9 for details.

The distinction between ΔI and axial offset should be made at this point. Axial offset, which is a measure of the distribution of core power between the top and bottom halves of the core, is defined as

$$\text{A.O.} = \text{axial offset} = \frac{\int^{Top} p(z)dz - \int^{Bot} p(z)dz}{\int^{Top} p(z)dz + \int^{Bot} p(z)dz} \times 100\%$$

A.O. is therefore independent of core power level. ΔI, on the other hand, gives an indication of the power split, but also proportional to core power.

$$\Delta I \;\alpha\; \int^{Top} p(z)dz - \int^{Bot} p(z)dz$$

Therefore, ΔI is proportional to the product of core power and A.O.

$$\Delta I \;\alpha\; \left[\text{A.O.}\right] \left[\int^{Top} p(z)dz + \int^{Bot} p(z)dz\right]$$

The ΔI contribution for overpower and overtemperature ΔT is provided through isolation amplifiers.

Therefore, f(ΔI) is a function of the indicated difference between top and bottom detectors of the power range nuclear ion chamber, with gains to be selected based on measured instrument response during plant startup tests, such that where q_t and q_b are the percent power in the top and bottom halves of the core, respectively, and $q_t + q_b$ is total core power in percent of rated power. The contribution of the f(ΔI) term in the Overtemperature ΔT and the Overpower ΔT is defined in the following terms.

If $q_t - q_b$ is within the range of -12% to +9%, the f(ΔI) is equal to 0. For each percent above +9% the ΔT trip setpoint is reduced by an equivalent of 2.5% of Rated Thermal

Power. For each percent below -12% the ΔT trip setpoint is reduced by an equivalent of 1.5% of Rated Thermal Power.

7.3.4.4 Incore Versus Excore Offset

One of the basic and fundamental assumptions made in axial offset usage is that the excore detector axial offset, can be directly related to the actual incore average axial offset. Therefore, prior to any applications of the excore detector axial offset it must first be established that there does exist a simple linear relationship between the average incore and corresponding excore axial offset values. This requires flux maps obtained during steady-state reactor power operation and corresponding excore detector currents. The power level is not important for this correlation since axial offset is independent of power. However, the power level does become important later when converting axial offset to ΔI and every time a full core flux map is obtained an accurate heat balance across the steam generators should also be obtained.

The results of the flux map and excore detector measurements listed previously are used to plot incore axial offset versus excore axial offset for each channel. Typical results are shown in Figure 7.3-2. Observation of the results should verify that there does exist a simple linear relationship between the average incore axial offset and the corresponding excore detector axial offset. Linearity is required since there is no provision to account for a nonlinear relationship between incore offset and excore axial offset.

Since all of the functional relationships of F(N)q as related to axial offset, are related to the average incore axial offset, there must exist a simple linear relationship between average incore and excore axial offset in order for the protection equation to provide adequate protection.

7.3.4.5 Excore Detector Current Versus Power

Having established a linear relationship in axial offset the next requirement is to establish the actual output of each individual detector at full power with an axial offset of 0%. This is required in order to adjust the process equipment and corresponding meters to insure that the amplifier operating bands cover the anticipated reactor core operating band. The criteria for setting the scales is given as follows. The gains are to be selected based upon measured instrument response during plant startup tests such that for $C_1I(Top) - C_2I(Bot)$[1] within $\pm\Delta I$ at 100% power, $f(\Delta I) = 0$, where $\pm\Delta I$ is specified by the setpoint study for each respective core. The $f(\Delta I)$ equipment responds to a range covering from 0 to 120% power. Since the linear operating range of the ΔT process equipment is from 0 to 10 volts, the required individual detector signal voltage must be set such that 100% is then 10/120 or 8.33 volts. 00259

In order to set this voltage one must know the value of each excore detector section current output when the core is operating at 100% power with an axial offset of 0%. However, prior to operating at 100% power it is required to have the setpoints set properly

[1] C_1 and C_2 are constants applied to the individual detector section currents in order to give the required calibrated signal voltage. Where $C_1I(Top) = V(Top)$ and $C_2I(Bot) = V(Bot)$.

to insure adequate protection. Thus a slight dilemma exists. On one hand, 100% power operation is required in order to set the equipment and on the other hand operation at 100% power cannot be accomplished until the equipment is set properly. This dilemma can easily be circumvented in the following manner. One can extrapolate the excore detector currents from lower power levels to the full power level (100%).

This is accomplished by normalizing all excore detector currents to the full power value of the sum of the two detectors as determined from a plot of power (MWT) versus the sum of the current output from each pair of excore detectors. The sum of the two detector currents when scaled by the summing amplifier (NM-310) determines the power level in the power range circuit. Using this technique all excore values can be related to the expected current output at full power operation. Typical results are shown in Figure 7.3-3. Observation of these figures show an excellent linear relationship between the core power level in MWT as determined from accurate heat balance measurements across the steam generators and the total detector current from each long ion chamber assembly. Note that this data does not require obtaining incore flux maps.

7.3.4.6 Incore Axial Offset Versus Excore Detector Current

Once the full power detector currents are established one can then normalize all data obtained to the equivalent full power condition. These values can then be plotted versus the corresponding average incore axial offset from the reduced results of detailed incore flux maps. Since axial offset is independent of power it is not necessary to reprocess the flux maps to full power operation.

In addition to knowing the excore detector currents at full power, the corresponding value at an axial offset of 0% is also required. This precise condition is extremely difficult to achieve and hold on an operating plant. However, if the required measurements have a wide range of axial offset values passing through zero on the negative and positive sides, it is a simple matter to interpolate to the value at zero axial offset. Typical results are shown in Figure 7.3-2. The required individual excore detector currents for a 0% axial offset at 100% power operation are then those values established at the intersection of the 0% axial offset line. In addition the other required detector output values are established for A.O.= $\pm \Delta I$ at 100% power (as specified by the setpoint study) to define the deadband and A.O.= $\pm$ 30% which in conjunction with the previous value defines the ramp of the $f(\Delta I)$ penalty.

7.3.4.7 Excore Detector Voltage Settings

The relationship of detector current to voltage can be determined by comparing the full power zero axial offset currents to the required process output voltage.

The calibration voltages are maintained current by the plant surveillance testing program. These voltages provide the values necessary to define the deadband width and the ΔT penalty rate for the ΔI term.

7.3.4.8 <u>One-Point Excore Detector Calibration</u> 002

Most excore detector axial offset calibrations are now performed using a single flux map combined with historical data of detection response. This one-point methodology is based on the following theory. (References 34 and 35).

Excore detector current can be represented by a straight line fit versus incore axial offset as:

$$I_K = \frac{P_{core}}{100} * (B_{0k} + B_{1k} * AO)$$

where P_{core} = Core Power (%)
B_{0k}, B_{1k} are curve fit constants 00259
K = T for Top detector
B for Bottom detector
AO = Incore axial offset

For each of the four detectors, a term ΔC_1 is defined as

$$\Delta C_1 = C_{1T} - C_{1B}$$

where $C_{1T} = B_{1T}/B_{0T}$ and $C_{1B} = B_{1B}/B_{0B}$
B_{1T} is the slope of the top excore detector current reading vs AO
B_{1B} is the slope of the bottom excore detector current reading vs AO
B_{0T} is the top excore detector current reading at AO=0 00259
B_{0B} is the bottom excore detector current reading at AO=0
ΔC_1 then becomes equal to the difference in ratios of the slope of excore current response to changes in the incore axial offset to the excore current reading at AO=0 for the top and bottom excore detectors.

Based on historical data, ΔC_1 can be represented as a linear function of F, the core mid-plane axial power value.

The excore axial offset calibration procedure is then performed as follows:

Step 1: A full core flux map is taken to determine the incore axial offset (AO), and core mid-plane axial power (F), at the same time measurements are made of total core power (P_{core}), and detector current (I_k).

Step 2: ΔC_1 is determined using F and the curve fit of historical data of ΔC_1 versus F.

Step 3: B_O and B_I is computed for each detector using the above relationships.

Step 4: The NIS is calibrated using the B_O values calculated above.

7.4 PLANT PROTECTION SYSTEMS

7.4.1 Reactor Protection System

7.4.1.1 Design Basis

The protection system consists of the equipment associated with both the reactor protection system and the engineered safety features. The quantity and types of instrumentation provided ensures safe and orderly operation of all systems and processes over the full operating range of the plant (Reference 13).

7.4.1.1.1 Reactor Protection System

GDC-14 Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

If the Reactor Protection System receives signals which are indicative of an approach to unsafe operating conditions, the system actuates alarms and/or opens the reactor trip breakers.

The basic reactor operating design defines an allowable operating region of power, pressure and coolant temperature conditions. This allowable range is defined by the primary tripping functions: the overpower ΔT trip, the overtemperature ΔT trip and the nuclear overpower trip. The operating region below these trip settings is designed so that no combination of power, temperatures, and pressure could result in a DNBR less than the applicable limit for any credible operational transient. Tripping functions in addition to those stated above, are provided to back up the primary tripping functions for specific abnormal conditions. A complete list of tripping functions may be found in Table 7.4-1.

See section 7.2 for details on reactor control features which are initiated prior to challenging reactor protection system features.

7.4.1.1.2 Engineered Safety Features Actuation Systems

GDC-15 Protection systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features.

Instrumentation provided for the Engineered Safety Features (ESF) is designed to prevent or limit fission product release from the core and to limit energy release, to signal containment isolation, and to initiate the engineered safety features equipment.

The engineered safety features systems are actuated by redundant logic and coincidence networks similar to those used for reactor protection. Each network actuates a device that operates the associated engineered safety features equipment, motor starters and valve operators. The channels are designed to combine redundant sensors, independent channel circuitry, and coincident trip logic. Where possible, different but related parameter measurements are utilized. This ensures a safe and reliable system in which a single failure will not defeat the intended function. The action initiating sensors, bistables and logic are shown in Figure 7.4-16. The Engineered Safety Features Actuation System actuates engineered safety features functions such as the Safety Injection System. Containment Isolation System, the Containment Air Cooling System, the Containment Spray System, reactor trip, feedwater isolation, etc.

7.4.1.1.3 Protection Systems Reliability and Demonstration of Functional Operability

GDC-19 Protection systems shall be designed for high functional reliability and in-service testability necessary to avoid undue risk to the health and safety of the public.

Protection channels required for full power operation are designed with sufficient redundancy to allow individual channel calibration and test to be made by use of signal substitution techniques during power operation without negating the reactor protection.

Superimposing of test signals is utilized during the testing of the Nuclear Instrumentation System.

Removal of one trip channel is accomplished by placing that channel in the tripped mode. For example, a two-out-of-three channel becomes a one-out-of-two channel. Testing will not cause a trip unless a trip condition exists in a concurrent channel.

GDC-25 Means shall be included for suitable testing of the active components of protection systems while the reactor is in operation to determine if failure or loss of redundancy has occurred.

The signal conditioning equipment of each analog protection channel in service at power is capable of being calibrated and tested independently by simulated analog input signals to verify its operation without tripping the reactor. The testing scheme includes checking through the trip logic to the trip breakers. Thus, the operability of each trip channel can be determined conveniently and without ambiguity. Functional operation of the power sources for the protection system is discussed in Section 8.

7.4.1.1.4 Protection System Failure Analysis Design

GDC-26 The protection systems shall be designed to fail into a safe state or into a state established as tolerable on a defined basis if conditions such as disconnection of the system, loss of energy (e.g., electrical power, instrument air), or adverse environments (e.g., extreme heat or cold, fire, steam, or water) are experienced.

Each reactor trip channel is designed on the “de-energize to operate” principle; a loss of instrument power to that channel causes the system to go into its trip mode.

Reactor trip is implemented by simultaneously interrupting power to the magnetic latch mechanisms on all drives allowing the full length rod clusters to insert by free fall. The reactor protection system is thus inherently safe in the event of a loss of power. This equipment is selected to withstand the most adverse environmental conditions to which it will be subjected; this also includes post-accident environment.

7.4.1.1.5 Redundancy of Reactivity Control

GDC-27 Two independent control systems, preferably of different principles, shall be provided.

The reactivity control system employing Rod Control Cluster (RCC) assemblies is discussed in Section 7.2 and the control system employing the Chemical and Volume Control System is discussed in section 3 and section 10.

7.4.1.1.6 Reactivity Control Systems Malfunction

GDC-31 The reactor protection system shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits.

Reactor shutdown with Rod Control Cluster (RCC) assemblies is completely independent of the normal control functions since the trip breakers interrupt the power to the full length rod mechanism regardless of existing control signals. Effects of continuous withdrawal of a RCC assembly and of deboration are described in Section 14.

7.4.1.1.7 Protection Actions

The Reactor Protection System is designed to automatically trip the reactor as itemized in Table 7.4-1.

For anticipated abnormal conditions, the protection system, in conjunction with inherent plant characteristics, and the Engineered Safety Features are designed to assure that: (a) limits for energy release to the containment are not exceeded; and (b) radiation exposure does not exceed 10CFR100 guidelines.

7.4.1.1.8 Protection Systems Redundancy and Independence

GDC-20 Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service of any component or channel of such a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served.

The Protection System consists of two discrete portions of circuitry: an analog portion consisting of two to four redundant channels which monitor various plant parameters in systems such as the Reactor Coolant System, Neutron Flux System, Pressurizer System, Steam System, containment pressure, etc.; and a digital portion consisting of two redundant logic channels (trains which receive inputs from the analog protection channels and performs the needed logic to initiate reactor trips, engineered safety features, etc.). Each digital channel is capable of actuating a separate and independent trip breaker in the case of the Reactor Protection System or the appropriate equipment required in the case of the Engineered Safety Features Systems. The intent is that "any single failure within the Protection System shall not prevent proper protection system operation when required".

Protection and operational reliability is achieved by providing redundant instrumentation channels for each protective function. These redundant channels are electrically isolated and physically separated. The channel design incorporates separate sensors, separate power supplies, separate rack and panel mounted equipment and separate relays for the actuation of the protective function. For protective functions where two-out-of-three or two-out-of-four redundant-coincident actuation is provided, a single channel failure will not impair the protective function nor will it cause an unnecessary unit shutdown.

The channelized concept is applied to both the analog and logic portions of the system. 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 voltage, the most likely mode of failure, in a channel or logic train will result in a signal calling for a trip. Design considerations for common mode failures are discussed in Reference 5.

The Engineered Safety Features Actuation System meets the single failure criterion as defined in IEEE Standard 279-1971. The analysis was included in a report titled "ECCS Actuation System " (Reference 6) and additional information was provided in References 7, 8 and 9. The NRC's evaluation and acceptance are discussed in Reference 10.

In certain applications, it is considered advantageous to employ control signals derived from individual protection channels through isolation amplifiers contained in the protection channel. In these cases, analog signals derived from protection channels for non-protective functions are obtained through isolation amplifiers located in the analog protection racks. (By definition, non-protective functions include those signals used for control, remote process indication, computer monitoring, etc.) The isolation amplifiers are designed such that a short circuit, open circuit, or the application of 118 VAC or 140 VDC on the isolated output portion of the circuit (i.e., nonprotective side of the circuit) will not upset the input (protection) side of the circuit. One type of an isolation amplifier is discussed in Reference 3; another type in Reference 4. Since the signals obtained through isolation amplifiers are never returned to the protection racks, any postulated failure in the control system will not prevent proper operation of the protection channel.

7.4.1.1.9 Protection Against Multiple Disability for Protection Systems

GDC-23 The effects of adverse conditions to which redundant channels or protection systems might be exposed in common, either under normal conditions or those of an accident, shall not result in loss of the protection function or shall be tolerable on some other basis.

Separation of redundant analog channels originates at the process sensors and continues along the field wiring and through containment penetrations to the analog protection racks. Physical separation is used to the maximum practical extent 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 channel. Redundant analog equipment is separated by locating modules in different protection rack sets. Each redundant protection channel set is energized from a separate instrument bus.

7.4.1.1.10 Single Failure Criterion

The protection system is designed to provide redundant (one out of two, two out of three or two out of four) instrumentation channels for each protective function and one out of two logic train circuits.

7.4.1.2 Reactor Protection System Description

Section 14 defines the region of acceptable operation with respect to analyzed transients and accidents, and the mitigation of those events. The function of the Reactor Protection System is to ensure safe operation within those boundaries by monitoring critical plant parameters such as RCS temperature, reactor power, pressurizer pressure, steam generator water level, and other plant parameters. Indications of a plant parameter moving to close to these boundaries brings about a reactor trip.

Adequate margins exist between the nominal steady state operating point and required trip points to preclude a spurious trip during design transients.

A block diagram of the Reactor Protection System showing various reactor trip functions and interlocks is shown in Figure 7.4-3.

7.4.1.2.1 Protection System Identification

All non-rack mounted protective equipment and components are provided with an identification tag or name plate which specifies that item's function and channel. Small electrical components such as relays have name plates on the enclosure which houses them. All cables are numbered with identification tags. These numbers are cross-referenced with cable schedule which specifies cable routing and function.

In addition, all associated reactor protection and engineered safety feature cables are identified by a color code, which is defined in Section 8.7 under "Cables and Raceways".

This color code distinguishes between redundant channels of reactor protection systems and redundant trains of engineered safety feature systems. Instruments and components are also tagged with color coded nameplates, and associated color coded cables are color marked immediately adjacent to instrument and components termination points.

For protection racks which house the protection rack mounted equipment, a color coded nameplate on the rack is used to differentiate between protective and non-protective sets. This provides immediate and unambiguous identification of protection sets.

7.4.1.2.2 Primary Power Source

The primary power sources for the Reactor Protection System and Engineered Safety Features Actuation System are described in Section 8.6 - Instrumentation and Control AC Power Supply Systems. This is the source of electrical power for the detecting instrumentation up to and including the bistable output devices.

The primary power sources for the Reactor Trip Logic and Engineered Safety Features Actuation Logic are described in section 8.5 - DC Power Supply Systems.

7.4.1.2.3 Protective Actions

7.4.1.2.3.1 Reactor Trip Description

Rapid reactivity shutdown is provided by the insertion of full length RCC assemblies by free fall. The full length control rod drive mechanisms must be energized for the full length RCC assemblies to remain withdrawn from the core. Control rod insertion occurs upon loss of power to the full length control rod drive mechanisms.

Duplicate series-connected circuit breakers, the reactor trip breakers, supply all power to the full length control rod drive mechanisms. These breakers are designed to interrupt power to the full length control rod drive mechanisms upon receipt of trip signals from the reactor protection system. Two devices in each breaker receive signals from the reactor protection system, either of which will trip the reactor trip breakers; an undervoltage trip device and a shunt trip device. The undervoltage trip device which is normally energized, becomes de-energized upon receipt of a trip signal and trips the breaker. Trip signals from the reactor protection system also energize the normally de-energized shunt trip device which in turn trips the breaker.

This design provides a passive trip device which will trip the reactor on loss of breaker control power or the receipt of a trip signal and a positive acting device which provides a backup if the passive device fails to trip the reactor trip breakers upon receipt of a trip signal. For each reactor trip, passive or active, a turbine trip is also initiated.

Certain reactor trip channels are automatically bypassed at low power where they are not required for safety. Nuclear source range and intermediate range trips are specifically provided for protection at low power or subcritical operation. For higher power operations they are bypassed by manual action.

During power operation, a sufficient amount of rapid shutdown capability in the form of control rods is administratively maintained by means of the control rod insertion limit monitors. Administrative control requires that all shutdown group rods be in the fully withdrawn position during power operation, except during testing.

A list of reactor trips, means of actuation and the coincident circuit requirements is given in Table 7.4-1. The interlock circuits, referred to in Table 7.4-1 (e.g. P7), are listed in Table 7.4-3.

Means are provided for manual initiation of protection system action. Failure in the automatic system does not prevent the manual actuation of protection functions. Manual actuation is designed to require the operation of a minimum of equipment. The manual actuating devices are independent of the automatic trip circuitry. Either of two manual trip devices located in the control room can initiate a reactor trip.

For monitoring nuclear flux, multiple trip settings are used. When it is necessary to change to a more restrictive trip setting to provide adequate protection for a particular mode of operation or set of operating conditions, the design provides positive means of assuring that the more restrictive trip setting is used. The devices used to prevent improper use of less restrictive trip settings are considered a part of the protection system and are designed in accordance with the criteria presented in this section.

7.4.1.2.3.2 Power Range High Neutron Flux Reactor Trip

The high trip setting provides protection during normal power operation. This circuit trips the reactor when two of the four power range channels read above the trip setpoint. There are two independent trip settings, a high and a low setting. The low setting which provides protection during startup can be manually bypassed when two out of four power range channels read above approximately 10 percent full power (P10). Three-out-of-four channels below approximately 10 percent full power automatically reinstates the low setting trip function. The high setting is always active.

7.4.1.2.3.3 Intermediate Range High Neutron Flux Reactor Trip

This trip provides protection during reactor startup. This circuit trips the reactor when one out of two intermediate range channels reads above the trip setpoint. The trip can be manually bypassed if two-out-of-four power range channels are above approximately 10 percent full power (P10). Three out of four channels below the P10 value automatically reinstates the trip function. The intermediate range channels (including detectors) are separate from the power range channels.

7.4.1.2.3.4 Source Range High Neutron Flux Reactor Trip

This trip provides protection during reactor startup. This circuit trips the reactor when one of the two source range channels reads above the trip setpoint. This trip can be manually bypassed when one out of two intermediate range channels reads above the P6 setpoint value. This trip is automatically reinstated when the power range is below P10 and when both intermediate range channels decrease below the value P6. This trip is also automatically bypassed by two out of four high power range signals (P10). The trip point is set between the source range cutoff power level and the maximum source range power level. The P10 automatic bypass point is many decades above the source range cutoff power level (S.R. offscale high); its purpose is to preserve the detectors.

7.4.1.2.3.5 Power Range High Flux Rate Trip

Two sustained rate protective trip functions have been incorporated in the Reactor Protection System. As implemented, these protective channels do not require differentiator circuits and are not highly sensitive to process or electronic noise. Furthermore, trip initiation requires two out of four logic so that spurious actuation of any single channel will not normally trip the reactor (see Figure 7.4-4).

This basic circuit has been used in Westinghouse reactors for many years in the “dropped rod alarm” feature which has proven to be trouble free. Setpoints for the new trip functions are comparable to those in the “dropped rod alarm” feature.

The High Flux Rate Trip is functionally similar to the dropped rod sensor discussed in WCAP 7380-L, “Topical Report, Nuclear Instrumentation System”. The rate sensor assembly is an operational amplifier unit which incorporates an adjustable lag network at one input and a nondelayed signal on the other. The unit compares the actual power signal with the delayed power signal received through the lag network and amplifies the difference. This amplified differential signal is delivered to two bistable units which trip when the level of this signal exceeds a preset amount.

Tripping of either unit indicates a power level change over the lag period which would be indicative of either dropped rods or an ejected rod. These bistable units are a latching type, ensuring that the necessary action will be initiated and carried to completion. Specifically, the units control two out of four logic matrices (see Figure 7.4-4) to provide a reactor trip and a control board annunciation signal. A reset switch on the associated power range drawer must be operated manually to remove the latching function and reset the bistables.

Operability of the trip functions associated with dropped rod and ejected rod protection is verified by introduction of a signal step change using the channel drawer test circuits. The time delay setting of the rate module is predetermined by analysis to correspond to high positive or negative power rates associated with the above events and tested during initial startup testing.

7.4.1.2.3.6 Positive Sustained Rate Trip

The positive portion of the high flux rate trip provides an added measure of protection against hypothetical Rod Ejection Accident and Uncontrolled RCCA Withdrawal at Power transient. The rate trip function assures an immediate reactor trip independent of the initial operating state of the reactor. In addition, the rate trip function provides diversity in support of the high flux level trip functions for the rod ejection events that would give the worst consequences, full power and zero power ejections. 00-334

The Positive Rate Trip trips the reactor when an abnormal rate of increase in nuclear power occurs in two out of four power range channels and is always active.

With credit for the rate trip and for the high level trip, it is possible to show that substantial margin exists between the true operating condition of the reactor and the limiting condition (the condition that would lead to local core damage in the unlikely event of the Rod Ejection Accident).

7.4.1.2.3.7 Negative Sustained Rate Trip

The negative portion of the high flux rate reactor trip function provides protection for the core (protection against low DNBR) in the event that two or more Rod Cluster Control Assemblies (RCCA's) fall into the core. This circuit trips the reactor when an abnormal rate of decrease in nuclear power occurs in two-out-of-four power range channels and is always active. This reactor protection actuation may occur when a single RCCA falls into the core, but certain RCCAs may only cause a skewed power shape.

The strong tendency of a PWR to follow its load will tend to overcome the change in core state; ie., due to dropped RCCAs, and return to the power level matching the perceived heat load. If the moderator coefficient of reactivity is weak (high boron concentration) the reactor may trip due to low primary pressure. If the moderator coefficient of reactivity is strong (low boron concentration) the reactor may not trip on low pressure, and the system will achieve a new equilibrium at a slightly lower temperature and pressure at essentially the original power level. The Reactor Protection System will ensure that the plant does not experience an unacceptable DNB ratio due to the abnormal power distribution in the reactor.

If a single RCCA is dropped, the typical result is a negative flux rate reactor trip. However, as indicated in section 14.4.3.2, the analysis for this event specifies that some single RCCA drops may not result in a safe condition. If a reactor trip does not occur, there is no operator action required to keep the plant in a safe condition. However, due to operational complexities, as indicated in SE 567, it is desirable to place the plant in a known safe condition. Therefore, as an alternative to recovering a dropped RCCA, the operator may manually perform a reactor trip, if an automatic reactor trip does not occur. Alarms alert the operator to the dropped RCCA.

7.4.1.2.3.8 Overtemperature ΔT Reactor Trip

The purpose of this trip is to protect the core against DNB for any combination of power, pressure, temperature, and axial core power distribution. Two out of four trip logic is used, with two channels per reactor coolant loop. For each channel, the indicated ΔT is used as a relative measure of reactor power and is compared with a continuously calculated setpoint. When the reactor coolant loop compensated ΔT is greater than or equal to the calculated setpoint, the affected channel is tripped. This is expressed by the following equation.

$$\Delta T_t \leq \Delta T_0 \left[K_1 - K_2 (T - 567.3) \frac{(1+t_1 s)}{(1+t_2 s)} + K_3 (P - 2235) - f(\Delta I) \right]$$

where

ΔT_o	= Indicated ΔT at Rated Thermal Power
T	= Average Temperature, °F
P	= Pressurizer pressure, psig
K_1	= ≤1.11
K_2	= 0.0090
K_3	= 0.000566
t_1	= 30 sec
t_2	= 4 sec

The f(ΔI) term protects against axial maldistributions of core power and is discussed in more detail in section 7.3.4.3.

The lead-lag dynamics in the overtemperature ΔT setpoint equation are introduced in order to compensate for delays inherent in the temperature measurements. These lags are due to the transport time through the core and coolant piping to the temperature detector (RTD) and the lags in the instrumentation. The difference between the lead time constant t_1 and the lag time constant t_2 is based upon the total lags in measuring T_{avg} and ΔT.

These time constants are then adjusted in order to obtain satisfactory margin in DNB in a rod withdrawal accident at power.

A reduction in the lead time constant of one second results in a reduction in the minimum DNB attained in the rod withdrawal accident of about 2%.

The accuracy in setting a time constant is better than 10%. However, accuracy in making the settings is not essential since, in the calibration, the lead is set on the high side which adds conservatism.

7.4.1.2.3.9 Overpower ΔT Reactor Trip

The purpose of this trip is to protect against excessive power level (fuel rod rating protection). This circuit trips the reactor on coincidence of two out of four signals, with two sets of temperature measurements per loop.

The setpoint for this reactor trip is continuously calculated for each channel by solving standard equations of the following form as described in Figure 3.1-2 in Reference 13.

$$\Delta T_{setpoint} = K_4 - K_5 \left[\frac{t_3 s}{t_3 s + 1} \right] T_{avg} - K_6 \left[T_{avg} - 567.3 \right] - f(\Delta I)$$

where

T_{avg} = operating average temperature

K_4 = ≤ 1.10

K_5 = 0.0275 for increasing T_{avg}; 0 for decreasing T_{avg}

K_6 = 0.002 for $T_{avg} > 567.3$; 0 for $T_{avg} < 567.3$

t_3 = 10 sec

The f(ΔI) term protects against axial maldistributions of core power and is discussed in more detail in section 7.3.4.3.

The rate dynamics time constant in the overpower ΔT setpoint equation, t_3, is also chosen to compensate for delays inherent in the temperature measurements.

The circuit for overpower protection is similar to the overtemperature circuit, trip point being determined from

$$\Delta T_p = \Delta T_o \left[K_4 \frac{(K_5)(t_3 s)(T)}{(1 + t_3 s)} \right] - K_6 \left[T_{avg} - 567.3 \right] - f(\Delta I)$$

where

ΔT_o = Indicated ΔT at Rated Thermal Power

T = Average Temperature, °F

K_4, K_5, K_6, t_3 and, f(ΔI) are as above.

A rod stop and turbine runback are initiated on approach to overpower ΔT trip actuation.

The overpower ΔT trip is designed to limit peak channel heat flux to 112% of its design value. Below the nominal design average temperature of 567.3°F, the ΔT overpower trip line is a constant since the average temperature dependent term is zero limited. This constant part of the trip line is below the 112% overpower line. However, no undue conservatism is added since the overpower line becomes flatter in the low temperature region.

For Tavg/ΔT Control and Protection System diagram, see Figure 7.4-5.

7.4.1.2.3.10 Overtemperature and Overpower ΔT Trip Lines

The absolute value of ΔT versus plant rated temperature and power is not important as far as reactor protection is concerned because the Overtemperature ΔT and Overpower ΔT trip setpoints are based upon percentages of the indicated ΔT at rated temperature and power rather than on the absolute value of ΔT. For this reason, the linearity of the ΔT signals as a function of RCS temperature and reactor power is of importance rather than the absolute value of the ΔT.

For axial offsets greater than 9% for positive tilt, 12% for negative, the ΔT Overpower and Overtemperature trip setpoints are automatically reduced by 1-1/2% for negative, 2-1/2% for positive, for each percent increase in imbalance. This reduction is applied to both ΔT trips.

Both circuits provide a turbine runback at a specified level below the trip point. Rod withdrawal block accompanies the turbine runback, and the runback follows a preprogrammed function until core ΔT is less than the runback limit.

If the flow decreases, the margin to DNB is reduced and the power must be decreased. However, for the same power to flow ration, ΔT will be larger. Therefore, the permissible ΔT increases somewhat at reduced flow. Note that flow is not variable; it can only change due to a change in the mechanical condition of the reactor coolant loops or core.

The Reactor Coolant Low Flow Reactor Trips and their sources are described in detail in Section 7.4.1.2.3.14.

7.4.1.2.3.11 Pressurizer Low Pressure Reactor Trip

The purpose of this trip is to protect against excessive core steam voids and to limit the necessary range of protection provided by the overtemperature ΔT trip.

The circuit trips the reactor on coincidence of two out of four low pressurizer pressure signals. Each channel is lead-lag compensated. This trip is blocked when three out of four power range channels and two out of two turbine first stage pressure channels read below approximately 10% power (P7).

7.4.1.2.3.12 Pressurizer High Pressure Reactor Trip

The purpose of this trip is to limit the range of required protection from the overtemperature ΔT trip and to protect against Reactor Coolant System overpressure. The reactor is tripped on coincidence of two out of three high pressurizer pressure signals.

7.4.1.2.3.13 Pressurizer High Water Level Reactor Trip

This trip is provided as a backup to the pressurizer high pressure reactor trip. The coincidence of two out of three high pressurizer water level signals trips the reactor. This trip is blocked when three out of four power range channels and two out of two turbine first stage pressure channels read below approximately 10% power (P7).

7.4.1.2.3.14Reactor Coolant Low Flow Reactor Trips

These trip protect the core from DNB for a low coolant flow or a loss of coolant flow. The means of sensing low coolant flow are as follows:

a. Low Primary Coolant Flow Reactor Trip

   The low coolant flow signal is actuated by the coincidence of two out of three low flow signals from either reactor coolant loop. The loss of flow in a single loop causes a reactor trip if operating above P8. The loss of flow in both loops causes a reactor trip if operating above P7. Note: P7 and P8 are set at approximately the same point (approximately 10% power).

b. Reactor Coolant Pump Breakers Open Reactor Trip

   Opening of the reactor coolant pump breakers results in a reactor trip by acting directly in the reactor trip circuits. Above the P7 setpoint the reactor is tripped on both open breaker signals. Above P8 the reactor is tripped on one. See note in paragraph (a) above. Each reactor coolant pump breaker generates a trip signal.

   The Reactor Coolant Pump breaker open signal is a non-safety related reactor trip maintained to provide diversity for protection from loss of flow accidents. Redundant signals are provided. The circuitry is configured such that a non-safety related malfunction cannot prevent a safety related protective action.

   Testing of the RCP breaker open signal is accomplished when the reactor coolant pumps are not required.

c. Reactor Coolant Pump Bus Underfrequency Reactor Trips

   Redundancy is provided by two underfrequency sensors per RCP bus. An underfrequency signal from both buses trips both Reactor Coolant Pumps. This results in a reactor trip as described in the preceding paragraph (b).

The underfrequency trip is a non-safety related protection feature maintained to provide diversity for the protection from loss of flow accidents. The circuitry is configured such that a non-safety related malfunction cannot prevent a safety related protective action.

Test points and signal injection points are provided to allow the testing of the Reactor Coolant Pump Bus Underfrequency Reactor trip. Testing has confirmed that this circuit path does not delay the reactor trip by more than 0.1 second.

d. Reactor Coolant Pump Bus Undervoltage Reactor Trip

Redundancy is provided by two voltage sensors per RCP bus. Above the P7 setpoint an undervoltage signal from both buses trips the reactor. In addition, this trip also auto-starts the Turbine Driven Auxiliary Feedwater Pump. See section 11.9.2.2 for details.

The undervoltage trip is a non-safety related protection feature maintained to provide diversity for the protection from loss of flow accidents. The circuitry is configured such that a non-safety related malfunction cannot prevent a safety related protective action. SE 168 justified a time delay of 1 sec. (60 cycles) for detection of an undervoltage condition prior to performing the undervoltage trip. The purpose of this time delay is to stabilize the NSP grid and reduce the probability of a system-wide blackout, and thus a station blackout. For analysis purposes, this time delay extended the overall trip time to a conservative 2.1 seconds from the initial loss of RCP power to the initiation of RCCA motion.

Test points and signal injection points are provided to allow the testing of the Reactor Coolant Pump Bus Undervoltage Reactor trip.

7.4.1.2.3.15 Safety Injection System (SIS) Actuation Reactor Trip

A reactor trip occurs when the safety injection system is actuated by signals listed in Table 7.4-1, item 9.

7.4.1.2.3.16 Turbine Generator Trip, Reactor Trip

The reactor trip on turbine trip, a non-safety related protection feature, is maintained to provide diversity to protect the reactor against loss of heat sink. The circuitry is configured such that a non-safety related malfunction cannot prevent a safety related protective action. A turbine trip is sensed by two out of three autostop oil pressure switches sensing low pressure or two out of two turbine stop valves closed. A turbine trip causes a direct reactor trip when operation above the 10% power level is measured by P9 permissive. This setting is required in accordance with the commitment to NUREG-0737 item II.K.3.10. The current setting reflects the load rejection capability of the Rod Control System as discussed in section 4.1.4.4.

The turbine control system automatically trips the turbine generator under a number of conditions. Details on these trips are discussed in Section 11.

7.4.1.2.3.17 Low-Low Steam Generator Water Level Reactor Trip

The purpose of this trip is to protect the reactor from a loss of heat sink. The trip is actuated on two out of three low-low water level signals in either steam generator. The same trip also starts the Auxiliary Feedwater pumps. See section 11.9.2.2 for details on Auxiliary Feedwater functions.

7.4.1.2.4 Electrical Isolation

The design criterion used to assure electrical isolation is that no analog signal which is required for initiation of reactor protection or engineered safety feature actuation is allowed to leave a set of protection channels. Where a protection signal is required for other than protective functions, an isolation amplifier (part of the protection set) is used to transmit the signal. The isolation amplifier prevents the perturbation of the protection channel signal (input) due to any disturbance of the isolated signal (output) which normally could occur near any termination of the output wiring external to the protection racks. A description of the nuclear instrumentation isolation amplifiers that are used in this plant is given in Reference 3. A description of the process control system isolating device is available in Reference 4.

7.4.1.2.5 Information Readout and Indication of Bypass

The protection system provides and displays information pertinent to system status and plant safety as well as various test conditions when some part of the system has been bypassed or taken out of service. Trips are indicated and identified down to the channel level.

7.4.1.2.6 Completion of Protection Action

Where operating (i.e. non-test conditions) 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 protection function are part of the protection system and are designed in accordance with the criteria of this section.

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

7.4.1.2.7 Indication

All transmitted signals (flow, pressure, temperature, etc.) which can lead to a reactor trip are either indicated or recorded in the control room for every channel.

All nuclear flux power range currents (top detector, bottom detector) and individual algebraic difference of calibrated bottom and top detector currents are indicated and/or recorded. The average nuclear power is also indicated and/or recorded.

7.4.1.2.8 Alarms

Alarms are also used to alert the operator of deviation from normal operating conditions so that he may take corrective action to avoid a reactor trip.

Further, actuation of any abnormal rod stop or trip of any reactor trip channel will actuate an alarm. Alarms and/or annunciators also alert the operator when a protection channel is placed in the test condition.

7.4.1.2.9 Derivation of System Inputs

Process Control and Protection inputs are a direct measurement of pertinent plant variables affecting plant operation and safety. The plant variables are:

a. Temperature, measured by sensors immersed in the fluid.

b. Flow, measured by ΔP (differential pressure) across elbows, venturi, orifices, etc. or inline devices such as rotameters, target meters, turbine meters, etc.

c. Pressure measured by direct communication to the tank, pressure vessel, pipe, etc. via stainless steel heavy-walled impulse lines.

d. Liquid level, measured by ΔP across a fixed reference leg and the measured liquid.

e. Nuclear power is measured by neutron detectors located in close proximity to the outside of the reactor vessel and measure the core leakage flux which is an indication of core power.

f. Other variables such as voltage, frequency, breaker position, valve position, turbine power, etc., are used to develop other protection logic and permissives.

7.4.1.2.10 Systems Repairs

The protection systems are designed with sufficient redundancy to perform online repairs per the Technical Specification, which defines minimum requirements for continued operation.

7.4.1.3 Performance Analysis

The safety related portions of the reactor protection system meet the performance analysis criteria as set forth in the following.

7.4.1.3.1 Quality of Components and Modules

The quality of the components and modules is such that low failure rates will result in minimum maintenance requirements. To achieve this goal, quality is considered and controlled from the original design to the final installation and testing.

In response to Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events", life cycle tests were performed on the reactor trip breaker shunt and undervoltage trip attachments to demonstrate that the attachments are suitable for reactor trip switchgear service and have adequate design margins (Reference 17). The results of the testing showed that the shunt trip attachment has adequate margin and is suitable as a backup to the undervoltage trip attachment for reactor trip switchgear service in compliance with Generic Letter 83-28. The testing also confirmed the suitability of the undervoltage trip attachment for reactor trip switchgear service.

Items 4.2.3 and 4.2.4 of Generic Letter 83-28 specify that the reactor trip breaker preventative maintenance and surveillance program should include life testing of the reactor trip breakers and periodic replacement of breakers or components consistent with the demonstrated life cycles. In response to Item 4.2.3, "Life Testing of Trip Breakers", the reactor trip breaker Life Cycle Testing Program discussed above and in Reference 17 was performed by the Westinghouse Owners Group. The results of that program were utilized in the development of the response to Item 4.2.4, "Periodic Replacement of Breakers or Components Consistent with Demonstrated Life Cycles", provided to the NRC by Reference 53.

Supplement 1 to Generic Letter 83-28, issued October 7, 1992, informed licensees that the actions of 4.2.3 and 4.2.4 as originally described in the enclosure to Generic Letter 83-28 were no longer needed. In light of reactor trip breaker operating experience since the issuance of Generic Letter 83-28, the NRC staff concluded that the actions already completed pursuant to Generic Letter 83-28 have been effective in improving reactor trip breaker reliability to open, and that further actions to address the end-of-life degradation in breaker reliability are not justified. Additionally, the NRC staff noted that since issuing Generic Letter 83-28, the NRC had promulgated the requirements for reducing the risk from ATWS events in 10 CFR Part 50, Section 50.62. The modifications associated with this regulation further reduce the risk resulting from the failure of reactor trip breakers.

Based on Supplement 1 to Generic Letter 83-28, and the operating experience with the Prairie Island reactor trip breaker shunt and undervoltage trip attachments, the 30 year replacement interval committed to in Reference 53 has been eliminated. The shunt and undervoltage trip attachments will be replaced as periodic preventative maintenance, inspection and surveillance testing dictate.

As originally committed in Reference 53, the remaining reactor trip breaker components, not specifically addressed by the Westinghouse Owners Group Life Cycle Testing Program, will also be replaced as periodic preventative maintenance, inspection and surveillance testing dictate.

7.4.1.3.2 Equipment Qualification

Proprietary type tests are performed on protection system equipment, to assure it will perform as needed to achieve system requirements under normal and transient conditions as required.

Details of environmental testing of engineered safety features related equipment in containment which are required to operate in the post-LOCA environment are described in Section 8.9.

In response to Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events", the reactor trip breaker shunt trip device and auto shunt trip panels were environmentally and seismically tested to demonstrate their capability to perform as specified (Reference 18). A shunt trip device was also aged and seismically tested to demonstrate that all performance requirements could be achieved (Reference 19).

7.4.1.3.3 Channel Integrity

Protection system channels are designed such that adverse conditions, related to the environment, energy supply, malfunctions and accidents, as applicable, do not negate the safety of the plant.

7.4.1.3.4 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 independence of redundant channels.

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

7.4.1.3.5 Separation of Redundant Protection Channels

The Reactor Protection System is designed to achieve separation between redundant protection channels. The channel design is applied to the analog and the logic portions of the protection system, and the functions are illustrated by Figure 7.4-7. Although the illustration is for four channel redundancy and for two-out-of-four coincident logic, the design is applicable to two and three channel redundancy. Separation of redundant analog channels originates at the process sensors and continues along the field wiring and through containment penetrations for each redundant channel. Analog equipment is separated by locating redundant components in different protection racks. Each protection channel set is energized from a separate a.c. instrument bus. Logic equipment separation is achieved by providing separate racks, each associated with individual trip breakers. Physical separation is provided between these racks. The reactor trip bistables are mounted in the analog protection racks and are the final operational component in an analog protection channel. Figure 7.4-7 depicts the functions of each bistable indicating that each one drives two relays, "C" and "D" which have normally open contacts. The contacts from the "C" relays are interconnected to form the required actuation two out of four coincident logic for tripping one breaker. The transition from instrument channel identity to logic identity is made at the logic relay coil/relay contact interface. As such, there is both electrical and physical separation between the analog and the logic portions of the protection system. The above logic network is duplicated for the other trip breaker using the contacts from "D" relays. Therefore, the two redundant reactor trip logic channels will be physically and electrically separated from one another. The Reactor Protection System is comprised of identifiable channels which are physically electrically, and functionally separated from one another. See section 8.7 for details on electrical separation requirements.

7.4.1.3.6 Loss of Power

A loss of power in the Reactor Protection System causes the affected channel to trip. All reactor protection circuits are deenergized to cause a trip, with the exception of the shunt trip. Availability of control power to the engineered safety features trip channels is continuously monitored. The Engineered Safety Features bistables are deenergized to actuate, except for containment spray which is energized to actuate.

7.4.1.3.7 Diversity

The design philosophy is to make maximum use of a wide variety of measurements. The protection system continuously monitors numerous diverse system variables. The extent of this diversity has been evaluated for a wide variety of postulated accidents and is discussed in Reference 13. Generally, two or more diverse protection functions would terminate an accident before intolerable consequences could occur.

Protective diversity is achieved in either of two ways: equipment diversity, by providing different types of instrumentation to monitor the same variable, or functional diversity, by monitoring different plant variables. Functional diversity entails some degree of equipment diversity, primarily with respect to sensors and setpoints. More importantly, however, functional diversity is not dependent on the calculated response of any one variable during an accident. As a converse of this, functional diversity is more complex to demonstrate since the response of several variables must be analyzed for each type of accident evaluated. The diversity rational includes the use of non-safety as well as safety related equipment.

7.4.1.3.8 Reactor Protection System and DNB

The following is a description of how the reactor protection system prevents DNB.

The plant variables affecting the DNB ratio are:

Thermal Power

Coolant flow

Coolant temperature

Coolant pressure

Core power distribution

Figure 7.4-5 illustrates Tavg/ΔT protection channels. Variations in both flow and power are monitored by the overpower and overtemperature ΔT trips since a decrease in flow would have the same effect on the measured loop ΔT signal as an increase in power. Periodic measurements using the incore instrumentation system are used to verify that the actual core power distribution is within design limits.

Reactor trips for a fixed high pressurizer pressure and for a fixed low pressurizer pressure are provided to limit the pressure range over which core protection depends on the overpower and overtemperature ΔT trips.

Reactor trips on nuclear overpower and low reactor coolant flow are provided for direct, immediate protection against rapid changes in these parameters. However for cases in which the calculated DNBR approaches the applicable limit, a reactor trip on overtemperature ΔT would also be actuated.

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The ΔT trip functions are based on the differences between measured hot leg and cold leg temperatures. These differences are proportional to core power. The ΔT trip functions are provided with a nuclear differential flux signal from the upper and lower ion chambers to reflect a measure of axial power distribution. This aids in preventing an adverse axial flux distribution which could lead to exceeding allowable core conditions.

The postulated abnormal conditions, the exact combination of conditions (reactor coolant pressure, core temperature, core power, instrumentation uncertainties, etc.) and its effects on DNBR are covered in each of the various accidents and transients analyzed in Section 14. 01-079

7.4.1.3.9 Specific Control and Protection Interactions

7.4.1.3.9.1 Nuclear Flux

Four power range nuclear flux channels are provided for overpower protection. Isolated outputs from all four channels are averaged for automatic rod control. If any channel fails in such a way as to produce a low output, that channel would be incapable of proper overpower protection. In principle, the same failure may cause rod withdrawal and hence, overpower. Two out of four overpower trip logic ensures that even with a failed channel a two out of three logic remains available to provide an overpower trip.

In addition, the control system responds only to rapid changes in indicated nuclear flux; slow changes or drifts are compensated by the temperature control signals. Finally, an overpower signal from any nuclear channel blocks automatic rod withdrawal. The setpoint for this rod withdrawal stop is below the reactor trip setpoint.

7.4.1.3.9.2 Coolant Temperature

Hot leg and cold leg temperature measurements are made for each reactor coolant loop to provide protection. In addition, by use of isolation amplifiers located in the protection rack, the temperature signals are used for control. The average temperature measurements and temperature difference measurements for each loop are used for protection with two channels per loop and two out of four reactor trip logic. The reactor control system uses the highest auctioneered of the four isolated average temperature measurements.

$$\text{Average Temp} = T_{avg} = \frac{T_{Hot} + T_{Cold}}{2}$$

$$\text{Temp. Difference} = \Delta T = T_{Hot} - T_{Cold}$$

The main requirement for reactor protection is that the temperature difference between the hot leg and cold leg vary linearly with power. All ΔT setpoints are in terms of full power ΔT; thus, absolute ΔT measurements are not required.

Reactor Protection logic using reactor coolant loop temperatures is two out of four with two channels per reactor coolant loop. This complies with all applicable IEEE 279 criteria.

Reactor control is based upon signals derived from protection system channels through isolation amplifiers so that no feedback effect can perturb the protection channels.

Since control is based on the highest average temperature from the four average temperature measurements, 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).

A common low flow alarm with an individual flow indicator for each reactor coolant loop bypass flow is provided on the main control board. The alarm and flow indicators provide the operator with immediate indication of a low flow condition in the bypass loops associated with any reactor coolant loop. The setting of the RTD bypass loop flow status light and alarm is between 50 and 300 gpm and is accurate to within $\pm 10\%$ of full range.

In addition, channel deviation signals in the control system give an alarm if any temperature channel deviates significantly from the other. Automatic and manual rod withdrawal blocks also occur if any one out of four nuclear channels indicates an overpower condition or if any two out of four temperature channels indicate an overtemperature or overpower condition. Two out of four trip logic is used to ensure that an Overtemperature or Overpower ΔT trip occurs, if needed, even with an independent failure in another channel. Finally, as shown in Section 14, the combination of trips on nuclear overpower, high pressurizer water level, and high pressurizer pressure also serve to limit an excursion for any credible rate of reactivity insertion. See section 4.6.1.5 for reactor coolant bypass loop temperature measurement development.

7.4.1.3.9.3 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 (See Figure 7.4-8). Isolated output signals from these channels are used for pressure control. These are used to control pressurizer spray and heaters and power operated relief valves. Pressurizer pressure is sensed by fast response pressure transmitters with a time response of better than 0.2 seconds.

Interlocking of two separate pressure channels prevents a single channel failure causing relief valve actuation, but a spurious high pressure signal from one channel may actuate a spray valve. Additional redundancy is provided in the protection system to ensure low pressure protection, i.e., two out of four low pressure reactor trip logic. Safety injection is actuated on two out of three pressurizer low pressure.

The pressurizer heaters are incapable of overpressurizing the Reactor Coolant System. Maximum steam generation rate with heaters is about 8,200 lb/hr, compared with a total capacity of two orders of magnitude greater for the two safety valves and for the two power operated relief valves as shown in Table 4.1-4. Therefore, overpressure protection is not required for a pressure control failure, however, two out of three high pressure trip logic is used.

Either of the two relief valves can easily maintain pressure below the high pressure trip point. The two relief valves are each manually controlled by a switch in the control room or automatically by two pressure channels one of which is independent of the pressure channel used for the pressurizer heaters. Since pressure changes as a result of pressurizer heater operation are slow, ample time and pressure alarms are available for operator action.

7.4.1.3.9.4 Pressurizer Level

Three pressurizer level channels are used for reactor trip (two out of three for high level). Isolated signals from these channels are used for level control, increasing or decreasing the pressurizer water level as required. 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). (See Figure 7.4-9a).

The design of the pressurizer water level instrumentation is a slight modification of the usual tank level arrangement using differential pressure between an upper and a lower tap. (See Figure 7.4-9b). The modification consists of the use of a sealed reference leg instead of the conventional open column of water.

Experience has shown that hydrogen gas can accumulate in the upper part of the condensate pot on conventional open reference leg systems in pressurizer level service. At Reactor Coolant System (RCS) operating pressures, high concentrations of dissolved hydrogen in the reference leg water are possible. On sudden depressurization accidents, it has been hypothesized that rapid effervescence of the dissolved hydrogen could blow water out of the reference leg and cause a large level error, measuring higher than actual level. To eliminate the possibility of such effects, a bellows is used in a pot at the top of the reference legs to prevent dissolving of hydrogen gas into the reference leg water.

The reference leg operating temperature remains at the local ambient temperature. This temperature varies somewhat over the length of the reference leg piping under normal operating conditions but does not exceed approximately 140°F. During a blowdown to atmospheric pressure, any reference leg boil off is confined to the condensate steam interface in the condensate pot at the top of the temperature barrier leg with only negligible effects on the accuracy of the level sensors. Flashing or effervescence within the reference leg itself does not occur. Therefore, the instrumentation provided senses low pressurizer level. The pressurizer liquid level measuring system was tested to verify that this system is capable of withstanding rapid depressurization and provides proper information within 1 second after depressurization. The system test was arranged to have a liquid level measuring system which consisted of a D/P electronic transmitter, a liquid level filled sensor bellows and capillary tubing assembly, which served as the reference leg connected to the high pressure side of the D/P cell. The level measuring system was connected to a half filled vessel of liquid and gas at a static pressure of 2250 psig. The pressure was rapidly released from 2250 psig to atmosphere from the test vessel. After depressurization tests, no damage occurred to the level measuring system and the test results verified the capability of this system to withstand rapid depressurization.

Calibration of the sealed reference leg system is done in place by application of known pressure to the low pressure side of the transmitter and measurement of the height of the reference column. The effects of static pressure variations are predictable. The largest effect is due to the density change in the saturated fluid in the pressurizer itself. The effect is typical of level measurements in all tanks with two phase fluid and is not peculiar to the sealed reference leg technique. In the sealed reference leg, there is a slight compression of the fill water with increasing pressure, but this is taken up by the flexible bellows. A leak of the fill water in the sealed reference leg can be detected by comparison of redundant channel readings on line and by physical inspection of the reference leg off line with the channel out of service. Leaks of the reference leg to atmosphere are immediately detectable by offscale indications on the control board. Further detection of leakage is provided by ERCS alarms for level deviation between redundant channels.

A reactor trip on pressurizer high level is provided to prevent filling the pressurizer in the event of a rapid thermal expansion of the reactor coolant. A rapid change from high rates of steam relief to water relief could be damaging to the safety valves, relief piping, and pressure relief tank. However, a level control failure cannot actuate the safety valves because the high pressure reactor trip is set below the safety valve set pressure. With the slow rate of charging available, overshoot in pressure before the trip is effective is much less than the difference between reactor trip and safety valve set pressures. Therefore, a control failure does not require protection system action. In addition, alarms occur in ample time for corrective manual action.

7.4.1.3.9.5 Steam Generator Water Level

Before describing control and protection interaction for these channels, it is beneficial to review the protection system basis for this instrumentation. (See Figure 7.4-10).

The basic function of the reactor protection circuits associated with 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 with no protective action, the steam generators would boil dry and cause an overtemperature-overpressure excursion in the reactor coolant. Reactor trips on temperature, pressure, and pressurizer water level will trip the unit before there is any damage to the core or Reactor Coolant System. Redundant auxiliary feedwater pumps are provided to remove heat and thus prevent residual heat, after trip, from causing thermal expansion and discharge of the reactor coolant through the pressurizer relief valves. Reactor trips act before the steam generators are dry to reduce the required capacity and starting time requirements of these pumps and to minimize the thermal transient on the Reactor Coolant System and steam generators. Independent trip circuits are provided for each steam generator for the following reasons:

a. Should severe mechanical damage occur to the feedwater line to one steam generator, it is difficult to ensure the functional integrity of level and flow instrumentation for that unit. For instance, a major pipe break between the feedwater flow element and the steam generator would cause high flow through the flow element. The rapid depressurization of the steam generator would drastically affect the relation between downcomer water level and steam generator water inventory.

b. It is desirable to minimize thermal transients on a steam generator for credible loss of feedwater accidents.

Automatic signal validation is used for control system inputs, which prevents any single protection system failure from affecting the control system. This validation is used to satisfy IEEE 279-1971, Section 4.7.3 criteria regarding protection/control interaction. The validation is known as Median Signal Select and includes deviation and signal value limit alarm flags.

Changes to any aspect of the signal validation associated with narrow range steam generator level must be verified operable by testing consistent with the testing performed on the original Median Signal Select.

As part of the resolution of USI A-47, "Safety Implications of Control Systems", the NRC Staff investigated control system failures that have occurred, or are postulated to occur, in nuclear power plants. The NRC Staff concluded that plant transients resulting from control system failures can be mitigated by the operator, provided that the control system failures do not also compromise operation of the minimum number of protection system channels required to trip the reactor and initiate safety systems. A number of plant specific designs were identified that required additional protection from such transients that could lead to steam generator overfill.

Steam generator overfill can affect the safety of the plant in several ways. The more severe scenarios could potentially lead to a steamline break or steam generator tube rupture. The basis for this concern is the following: (1) the increased dead weight and potential seismic loads placed on the main steamline and its supports should the main steamline be flooded; (2) the loads placed on the main steamlines as a result of the potential for rapid collapse of steam voids resulting in water hammer; (3) the potential for secondary safety valves sticking open following discharge of water or two phase flow; and (4) the potential inoperability of the main steamline isolation valves, main turbine stop valves or atmospheric dump valves from the effects of water or two phase flow.

Specifically, as a result of the resolution of USI A-47, the NRC Staff concluded that all PWR plants should provide automatic steam generator overfill protection and that plant procedures and technical specifications should include provisions to verify periodically the operability of the overfill protection and to assure that automatic overfill protection is available to mitigate main feedwater overfeed events during reactor power operation.

Generic Letter 89-19, "Request for Action Related to Resolution of Unresolved Safety Issue A-47 "Safety Implication of Control Systems in LWR Nuclear Power Plants" Pursuant to 10 CFR 50.54(f)", was issued on September 20, 1989 by the NRC Staff in response to the steam generator overfill concerns raised by the resolution of USI A-47. Generic Letter 89-19 recommended that all Westinghouse plant designs provide automatic steam generator overfill protection to mitigate main feedwater overfeed events. The Generic Letter further recommended that plant procedures and technical specifications for all Westinghouse plants include provisions to periodically verify the operability of the main feedwater overfill protection and ensure that the automatic overfill protection is operable during reactor power operation.

The original design for steam generator overfill protection is initiated on a steam generator high water level signal based on a two out of three initiating logic which is safety grade but uses one out of the three channels for both control and protection. The feedwater control system was upgraded in 1989 for Unit 2 and 1990 for Unit 1. The control system now uses all three narrow range steam generator level channels for protection and control, with the implementation of a Median Signal Select on steam generator level control channels to provide signal validation. This prevents protection/control interaction upon failure a single level channel and is used to satisfy IEEE 279-1971, section 4.7.3 criteria for reactor protection.

Actuation of steam generator overfill protection isolates feedwater to the steam generators by tripping the main feedwater pumps and closing the feedwater main and bypass control valves.

Generic Letter 89-19 concluded that the type of steam generator overfill protection utilized is acceptable if:

a. The feedwater control system is not powered from the same source as overfill protection.

b. Overfill protection and feedwater control are not located within the same cabinets.

c. Overfill protection and feedwater control signals are routed such that a fire is not likely to affect both systems.

d. Plant procedures and Technical Specifications include requirements to periodically verify operability of overfill protection.

Each of these criterion was individually addressed in the response to Generic Letter 89-19 (Reference 36). The response was provided in the context of the original design and then the added benefit of the upgraded feedwater control system, with Median Signal Select, was discussed.

With respect to the system power requirements, overfill protection is provided through trip bistables in the reactor protection analog instrumentation racks, which are powered from the four 120 VAC instrument buses. The feedwater control system is powered from redundant 120 VAC power supplies. The failure of a single 120 VAC instrument bus will have no effect on automatic feedwater control.

The overfill protection and feedwater control systems are physically located in separate cabinets.

No control signal cables are routed with protection cables. This is the case for the feedwater control and overfill protection systems; thus the likelihood of a fire affecting both systems is minimized.

In response to Generic Letter 89-19, a License Amendment Request was submitted (Reference 37) to incorporate feedwater isolation limiting conditions for operations and steam generator high level surveillance requirements into the Prairie Island Technical

Specifications. The requested Technical Specification changes were approved by Reference 38.

The feedwater isolation surveillance procedures were also revised to verify that control valves move from full open to full closed in 5 seconds or less upon deenergizing either air supply solenoid valve.

Generic Letter 89-19 was closed out by the NRC Staff in Reference 39.

7.4.1.3.10 Steam Line Pressure

Three pressure channels per steam line are used for steam break protection (two out of three low pressure signals for any steam line actuates safety injection). One of these channels is used to control the power operated relief valve on the steam line. These valves are typically rated at 10% of the safety valve capacity. A spurious high pressure signal from the channel used for control will open the relief valve and cause a reduction in pressure. This is a slow rate of steam release equivalent to approximately 2-3% power at 100% power steam pressure or approximately 7% power at zero power steam pressure. Spurious opening of a relief valve is bounded by the small steam line break analyzed in Section 14. In that analysis the safety injection signal was generated by the pressurizer instrumentation and not the steam line pressure instrumentation. Therefore, control failure does not create a need for the protection, and two-out-of-three logic is acceptable.

7.4.1.3.11 Normal Operating Environment

Temperature in the control room and adjoining equipment room is maintained for personnel comfort at 70°F $\pm$ 15°F. Protective equipment in this space is designed to operate within design tolerance over this temperature range.

Design specifications for this equipment specify no loss of protective function over the temperature range from 40°F to 120°F. Thus there is a wide margin between design limits and the normal operating environment for control room equipment.

Within containment, the normal operating temperature for protective equipment except excore neutron detectors is maintained below 120°F. Protective instrumentation is designed for continuous operation within design tolerance in this environment. Excore neutron detectors are designed for continuous operation within design tolerance in this environment. Excore neutron detectors are designed for continuous operation at 135°F, and the normal operating temperature is maintained below this value. Thermocouples mounted adjacent to each detector well provide a temperature input of the detector environment and is displayed, logged, and alarmed by ERCS. The detectors are able to withstand operation at 175°F for short durations (8 hours). Process instrumentation in containment which is vital to plant protection is designed to survive the post accident environment long enough to perform their protective function.

Qualification testing has been performed on various safety systems such as process instrumentation, nuclear instrumentation, and relay racks. Details of the Environmental Qualification Program are discussed in Section 8.9.

7.4.1.3.12 Response to Salem ATWS Event

In response to the ATWS events that occurred at the Salem Plant on February 22 and 25, 1983, Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events", was issued. The actions required by Generic Letter 83-28 were developed by the NRC Staff based on information contained in NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant". The specified actions fell into four areas: posttrip reviews, equipment classification and vendor interface, postmaintenance testing and reactor trip system reliability improvements.

The response to Generic Letter is provided in Reference 20. A summary of the Generic Letter 83-28 action items and the dates corresponding to the issuance of the NRC evaluation of each item is provided in Table 7.4.6. The NRC has verified the proper implementation of the equipment classification, vendor interface, post maintenance testing and reactor trip system reliability portions of Generic Letter 83-28 by an inspection summarized in Reference 32. The ATWS Mitigation System Actuating Circuitry (AMSAC) System installed in response to 10 CFR Part 50 Section 50.62 is described in Section 7.11.

7.4.1.4 Inspection and Testing

A plan for periodic component and system testing and material examinations was prepared for use throughout plant life.

7.4.1.4.1 Channel Bypass or Removal from Operation

The system is designed to permit any one analog channel through its bistable to be maintained, tested, and calibrated during power operation without system trip. Channel bypass and/or removal from operation facilitates these procedures.

During such testing operations the active parts of the system using two out of four logic meet the single failure criterion, when the channel under test is either tripped or makes use of superimposed test signals which do not negate the detector signal.

EXCEPTION: "One out of two" systems are permitted to violate the single failure criterion during channel bypass provided that acceptable reliability of operation can be otherwise demonstrated, and bypass time interval is short. See Section 7.4.1.4.5.

7.4.1.4.2 Additional Considerations for Test and Calibration

The bistable portions of the protective system (e.g., relays, bistables, etc.) provide trip signals after signals from analog portions of the system reach preset values. Capability is provided for calibrating and testing the performance of the bistable portion of protective channels and various combinations of the logic networks during reactor operation.

The analog portion of a protective channel (e.g., sensor and amplifier) provides an analog signal of the reactor or plant parameter. The methods for checking the analog portion of a protective channel during reactor operation include: a) varying the monitored parameter, b) simulating typical signals, and c) comparison checks between identical channels or between channels which bear a known relationship to each other.

The design provides for controlled access to all trip settings, module calibration adjustments, test points, and signal injection points.

7.4.1.4.3 Reactor Trip Signal Testing

In the source and intermediate ranges where the trip logic is one out of two for each range, bypasses are provided for testing.

Nuclear instrument power range channels are tested by superimposing a test signal on the normal sensor signal so that the reactor trip protection is not bypassed. Based upon coincident two out of four logic, this does not trip the reactor; however, a trip will occur if a reactor trip is required.

Provision is made for the insertion of test signals in each analog loop. This enables testing and calibration of meters and bistables. Transmitters and sensors are checked against each other using plant read-out equipment during normal power operation.

7.4.1.4.4 Process Analog Protection Channel Testing

Provisions are made to manually place the output of the analog bistable protection channel in a tripped condition for "at power" testing.

The basic arrangement of elements comprising a representative analog protection channel is shown in Figure 7.4-11. These elements include a sensor or transmitter, power supply, bistable, bistable trip switch and proving lamp, test operate switch, test annunciator, test signal injection jack, and test points. A portion of the logic system is also included to illustrate the overlap between the typical analog channel and the corresponding logic circuits. The analog system symbols are given in Figure 7.4-12.

Each process protection rack includes a test panel containing those switches, test jacks and related equipment needed to test the channels contained in the rack. A hinge cover encloses a portion of the test panel. Opening the cover or placing the test operate switch in the "TEST" position automatically initiates an alarm. The test panel cover is designed such that it cannot be closed unless the test signal plugs (described below) are removed.

Closing the test panel cover mechanically returns the test switches to the "OPERATE" position.

Testing of process analog protection channels requires that the bistable output relays of the channel under test be placed in the tripped mode prior to proceeding with the analog channel tests. Thus, for the channel under test, the relay elements in the two out of three or two out of four coincident matrices will be in the tripped mode during the entire test of that channel. It is observed that the remaining channels of the two out of three or the two out of four protective functions meet the single failure criterion when a channel is bypassed or tripped. Placing the bistable trip switch in the tripped mode deenergizes (trips) the bistable output relays and connects a proving lamp to the bistable output circuit. This permits the electrical operation of the bistable to be observed and the bistable set point relative to the channel analog signal to be verified. Upon completion of test of the analog channel, the bistable trip switches must be manually reset to their operate mode. Closing the cover of the test panel will not transfer the bistable trip switches from their tripped to their operate position.

Process analog channel testing is accomplished by simulating a process measurement signal, varying the simulated signal over its signal span and checking the correlation of bistable set points, channel readouts and other loop elements with precision portable readout equipment. (See Figure 7.4-11.) Test jacks are provided in the test panel for injection of the simulated process signal into each process analog protection channel. Test points are provided in the channel to facilitate an independent means for precision measurement and correlation of the test signal. This procedure does not require any tools nor does it involve in any way the removal or disconnection of wires in the channel under test. In general, the analog channel circuits are arranged so the channel power supply is loaded and is providing sensing circuit power during channel test. Load capability of the channel power supply is thereby verified by channel test.

7.4.1.4.5 Nuclear Instrumentation Channel Testing

Nuclear instrumentation system (NIS) channels are tested by superimposing the test signal on the actual detector signal being received by the channel. The output of the bistable is not placed in a tripped condition prior to testing. A valid trip signal would then be added to the existing test signal, and thereby cause channel trip at a somewhat lower percent of actual reactor power. Protection bistable operation is tested by increasing the test signal (level signal) to the bistable trip level and verifying operation at control board alarms and/or at the NIS racks.

An NIS channel which can cause a reactor trip through one out 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. The power range channels do not require bypass of the reactor trip function for test, since two out of four protection logic is used. In all cases the bypass condition and the channel test condition are alarmed on the NIS drawer and at the main control board. An interlock feature between the bypass switch and channel test switch on each channel keeps the test signal from being activated until the bypass function has been inserted. Administrative control is required to ensure that only one protection channel is placed in the bypass condition at any one time. The power range reactor trips are not affected by the bypass function described above. Therefore, the power range trips will be active if required. The channel test circuit is designed so that it cannot reduce the channel signal level below the signal being received from the NIS detector.

7.4.1.4.6 Logic Channel Testing

The general design functions of the logic systems are described below. The trip logic channels for a typical two out of three and a two out of four trip function are represented in Figure 7.4-13. Contacts from the "A" and "B" relays are arranged in a two-out-of-three trip matrix and contacts from the "C" and "D" relays (not same as shown in Figure 7.4-7) are in a 2 out of 4 matrix. This figure is not to show specific actual hardware implementation but to illustrate a typical switching function that causes a breaker trip via the undervoltage coil of the breaker. This approach is consistent with a deenergize to trip preferred failure mode. For increased reliability, a similar logic matrix energizes the shunt trip device, an energize to trip coil of the breaker. The logic system testing includes exercising the reactor trip breakers to demonstrate system integrity. Bypass breakers are provided for this purpose. During normal operation, these bypass breakers are open. To prevent simultaneous closure of both bypass breakers, an electrical interlock is used. Indication of a closed condition of either bypass breaker is provided locally, on the test panel, and on the main control panel.

As shown in Figure 7.4-13, the trip signal from the logic network is simultaneously applied to the main trip breaker associated with the specific logic chain as well as the bypass breaker associated with the alternate trip breaker. Should a valid trip signal occur while AB-1 is by-passing TB-1, TB-2 will be opened through its associated logic train. The trip signal applied to TB-2 is simultaneously applied to AB-1 thereby opening the bypass around TB- 1. TB-1 would either have been opened manually as part of the test or would be opened through its associated logic train which would be operational or tripped during a test.

Lights and an event recorder are provided at the respective Trip Logic Panels to indicate the operation of the logic relays, and logic network trip signals to the undervoltage and/or shunt trip devices of the breakers.

The following procedure illustrates the typical method used for testing Trip Breaker No. 1 and its associated logic network.

a. Rack-in and close AB-1.

b. Select function to be tested.

c. Sequentially deenergize the trip relays (A1, A2, A3) for each logic combination (1-2, 1-3, 2-3) using test pushbuttons. Verify that the logic network deenergizes the undervoltage coil and energizes the shunt trip coil on TB-1 for each logic combination.

d. Repeat “C” for each function.

e. Reset TB-1.

f. Trip and rack out AB-1.

In order to minimize the possibility of operational errors (such as tripping the reactor inadvertently or only partially checking all logic combinations), each logic network includes a logic channel test panel. This panel includes those switches, indicators and recorders needed to perform the logic system test. The arrangement is illustrated in Figure 7.4-14. The test switches used to de-energize the trip bistable relays operate through interposing relays as shown in Figures 7.4-11 and 7.4-13. This approach avoids violating the isolation philosophy used in the analog channel design. Thus, although test switches for redundant channels are conveniently grouped on a single panel to facilitate testing, physical and electrical isolation of redundant protection channels are maintained by the inclusion of the interposing relay which is actuated by the logic test switches.

7.4.2 Engineered Safety Features Instrumentation

7.4.2.1 Design Basis

The engineered safety features instrumentation measures temperatures, pressure, flows, and levels in the reactor coolant system, steam system, reactor containment and auxiliary systems, actuates the engineered safety features, and monitors their operation. Process variables required on a continuous basis for the startup, operation, and shutdown of the unit are indicated, recorded and/or controlled from the control room. The quantity and types of process instrumentation provided ensures safe and orderly operation of all systems and processes over the full operating range of the plant.

Certain controls and indicators which require a minimum of operator attention, or are only in use intermittently, are located on local control panels near the equipment to be controlled. Monitoring of the alarms of such control systems is provided in the control room.

Instrumentation and controls provided for the protective systems are designed to trip the reactor, when necessary, to prevent or limit fission produce release from the core and to limit energy release; to signal containment isolation; and to control the operation of engineered safety features equipment.

The engineered safety features systems are actuated by the engineered safety features actuation channels. Each coincidence network actuates an engineered safety features actuation device that operates the associated engineered safety features equipment, motor starters and valve operators. The channels are designed to combine redundant sensors, and independent channel circuitry, coincident trip logic and different parameter measurements so that a safe and reliable system is provided in which a single failure will not defeat the channel function. The action initiating sensors, bistables and logic are shown in the figures included in the detailed Engineered Safety Features Instrumentation

Description given in Section 7.4.2.2.1. The Engineered Safety Features Instrumentation System actuates the equipment and/or Systems listed in Section 7.4.2.2.

The same channel isolation and separation criteria as described for the reactor protection circuits are applied to the engineered safety features actuation circuits.

The passive accumulators of the Safety Injection System do not require signal or power sources to perform their function. The actuation of the active portion of the Safety Injection System is from signals described in Table 7.4-1.

The containment air fan coil units are normally in use during plant operation. These units are in the automatic sequence which actuates the engineered safety features upon receiving the necessary signals indicating an accident condition.

The process instrumentation required for Engineered Safety Features actuation is given in Table 7.4-4.

The logic diagram for containment spray actuation as well as for safety injection, steam line isolation and containment isolation, is shown in Figure 7.4-15. A single containment isolation signal will close off the required lines. Reactor coolant pump process lines for cooling and seal water are not isolated.

The containment isolation signals provide the means of initiation of isolation of the various pipes passing through the containment walls as required to prevent the release of radioactivity to the outside environment in the event of a loss of coolant accident.

The engineered safety features actuation circuits are designed on the principle that the safeguard bistables (See Figure 7.4-16) are de-energized to actuate with the exception that the containment pressure bistables for spray actuation are energized to operate in order to avoid spray operation on inadvertent power failure.

The availability of control power to the engineered safety features trip signals is continuously indicated by means of indicating lights on the engineered safety features panels. Loss of control power for the engineered safety features actuation signals is annunciated in the control room.

The Engineered Safety Features Actuation System is designed to meet the single failure criterion.

7.4.2.2 Description

The Engineered Safety Features (ESF) actuation system automatically initiates the following ESF actuation signals when any of the following conditions exist:

a. Safety Injection Signal (SIS)

   1. Pressurizer low pressure (2-out-of-3); this can be manually blocked when the pressurizer pressure (2-out-of-3) is below preset value.

   2. High containment vessel pressure (2-out-of-3);

   3. Low steam line pressure per loop (2-out-of-3); this can be manually blocked when the pressurizer pressure (2-out-of-3) is below a given set point.

b. Steam Line Isolation Signal

   1. Coincidence of SIS and Hi-Hi steam flow (1-out-of-2) isolates the affected steam line.

   2. Coincidence of SIS and Lo-Lo T_{avg} (2-out-of-4) and Hi steam flow (1-out-of-2) isolates the affected steam line.

   3. Hi-Hi containment pressure (2-out-of-3); isolates both steam lines.

c. Containment Spray Signal

   1. Six hi-hi containment pressure containment spray signals (three from SIS and three from Steam Line Isolation) are divided into three sets of two signals each. Coincidence of one out of two in three out of three (1/2 in 3/3) sets actuates the Containment Spray Signal.

d. Containment Isolation Signal

   1. Occurs when an SIS is present.

e. Containment Ventilation Isolation Signal

   1. Occurs when an SIS is present.

   2. Manual initiation of a Containment Spray Signal.

   3. Manual initiation of a Containment Isolation Signal.

   4. High Radiation (1-out-of-2) in Containment Purge System

f. Feedwater Isolation Signal

1. Occurs when an SIS is present.
2. Hi-Hi Steam Generator Level (2-out-of-3 in any steam generator).
3. Coincidence of Reactor Trip and Lo T_{avg} (2-out-of-4).

g. Auxiliary Feedwater Signal

1. Occurs when an SIS is present.
2. Lo-Lo Steam Generator Water Level (2-out-of-3 in any steam generator).
3. Undervoltage on RC Pump Bus (1-out-of-2 per bus on both buses). Starts only the Turbine Driven Auxiliary Feedwater Pump.
4. Trip of Both Main Feedwater Pumps

Each signal can also be generated manually. The manual or automatic ESF signal furnishes signal input required for:

Reactor Trip

Start of emergency diesel generators

Start of Safety Injection system

Start of a Cooling Water pump

Start of Containment Fan Cooler (in slow speed)

Start of Residual Heat Removal system

Start of Shield Building Ventilation system

Start of Auxiliary Building Special Ventilation system

Start of Control Room Special Ventilation system

Start of Component Cooling Water system

Transfer of Containment Fan Coolers from chilled water to cooling water

Isolation of the CRDM cooling coil units

Start of Control Room Chilled Water Pump

Close the Control Room Chilled Water Crossover Valves

Trip the Condensate Pumps

Figure 7.4-16 shows the sensors, bistables and logic matrix for the Engineered Safety Features.

The instrumentation used to monitor the effectiveness of the Engineered Safety Features system is discusses in section 7.10.

7.4.2.2.1 ESF Input Instrumentation

Instrumentation which is used to develop ESFAS signals are discussed in various sections of the USAR. The table below is a cross-reference for these locations.

Containment Pressure	7.4.2.2.1.1
Feedwater Pump Trip	11.9.2.1
High Radiation	7.5.2.2, 7.5.2.3, 7.5.2.4
Pressurizer Pressure	7.4.1.3.9.3
RCP Bus Undervoltage	7.4.1.2.3.14
RCS Average Temperature	7.4.1.3.9.2
Reactor Trip	7.4.1.2.3.1
Steam Flow	7.4.2.2.1.2
Steam Generator Water Level	7.4.1.3.9.5
Steam Line Pressure	7.4.1.3.10

Table 7.4-4 provides further information on the process instrumentation which provides signals to the Engineered Safety Features actuation circuitry.

7.4.2.2.1.1 Containment Pressure

Six channels, monitoring containment pressure, derived from four pressure taps, reflect the effectiveness of the containment and cooling systems and other engineered safety features. High pressure indicates high temperatures and reduced pressure indicates reduced temperatures. Indicators and alarms are provided in the control room to inform the operator of system status and to guide actions taken during recovery operations. Containment pressure indication will be used to distinguish between various incidents.

Redundant containment pressure signals are provided to isolate the containment. Each of the three pairs of differential pressure transmitters external to the containment in the auxiliary building have their own connection to the containment. Remote indicating facilities, and alarm signals are provided from each transmitter.

Actuation setpoints are provided in the following manner. SI actuation occurs on the lowest setpoint using a unique set of three bistables, and Steam Line isolation occurs on a higher setpoint using a unique set of three bistables. Containment Spray actuation occurs using a second setpoint on each of the SI and Steam Line Isolation bistables. The containment spray setpoint is the highest setpoint on each of the six bistables.

The containment pressure setpoint was the subject of TMI action plan item II.E.4.2(5) (NUREG 0737). The action plan item requested that the containment pressure setpoint that initiates containment isolation for nonessential penetrations be reduced to the minimum, compatible with normal operation. NSP's responses (References 59, 60 and 61) justifying a 4 PSIG set point, were found to be acceptable by the NRC (Reference 62).

7.4.2.2.1.2 Steam Flow

Four fully qualified 1E channels of Steam Flow provide engineered safeguards functions, reactor control functions, indication and recording of steam flow information.

The Steam flow instrumentation provides steam line break protection under two settings. First, 1 out of 2 Hi-Hi steam flow signals on a single steam line coincident with a Safety Injection Signal (SIS) will isolate the effected steam line. Second, 1 out of 2 Hi steam flow signals on a single steam line coincident with a SIS and 2 out of 4 Lo-Lo T_{avg} signals will isolate the effected steam line.

For reactor control the steam line flow signal is used in conjunction with other signals to generate the feedwater control signal. This signal is used to regulate the feedwater regulating valves and the feedwater bypass valves. See section 7.2.2.4 for information on the feedwater control system.

Indication of steam flow channel actuation occurs via annunciators and status lights. ERCS records indication of steam flow channel actuation and values. Each control signal is compensated for steam pressure and is displayed on a CB meter; the control system validated average compensated steam flow is displayed on each steam flow/feed recorder.

7.4.2.2.2 ESF Actuation Indication

Instrumentation which monitors the effectiveness of ESF Actuation is addressed under section 7.10.

7.4.2.3 Instrumentation Used During Loss of Coolant Accident

Instruments which are designed to function for various periods of time at the onset of a major or loss of coolant accident are those which govern the operation of Engineered Safety Features. Electrical equipment for the Engineered Safety Features is located inside the containment and in the auxiliary building. Table 7.4-5 is a listing of the equipment inside the containment which is required for post-LOCA operation and the duration required.

Pressurizer pressure transmitters may be required to actuate ESF for an accident in containment. The transmitters are located inside the containment because an equivalent signal cannot be obtained from a sensor location more isolated from the reactor.

It should be emphasized, however, that for the large loss of coolant incidents the initial suppression of the transient is independent of any detection or actuation signal because the water level will be restored to the core by the passive accumulator system.

All pumps used for safety injection and containment spray are located outside the containment. The operation of the equipment can be verified by instrumentation which will not be affected by the accident.

Refueling water tank instrumentation also provides information for evaluating the conditions necessary to initiate the recirculation mode of operation. See Section 6 for further details.

The refueling water storage tank level instrumentation provides additional information to determine the relative size of a reactor coolant leak.

Considerations have been given to all the instrumentation and information that will be necessary for the recovery time following a loss of coolant incident. Instrumentation external to the reactor containment such as radioactivity monitoring equipment will not be affected by this postulated incident and will be available to the operator.

7.4.2.4 Performance Analysis

The Engineered Safety Features Actuation System meets the same specifications and performance requirements as the Reactor Protection System. See section 7.4.1.3 for more information on ESF performance features.

Redundant instrumentation is provided for all inputs to the protective systems and vital control circuits. Where wide process variable ranges and precise control are required, both wide range and narrow range instrumentation is provided.

All electrical and electronic monitoring instrumentation required for safe and reliable operation is supplied from the vital instrumentation buses.

Any accident requiring emergency core cooling would involve low pressurizer pressure. Emergency core cooling is accomplished by the SIS actuation from the reactor coolant system variables. Actuation is initiated by low pressurizer pressure.

A safety injection block switch is provided to permit the reactor coolant system to be depressurized and its water level lowered for maintenance and refueling operations without actuation of the Safety Injection System. This manual block switch is interlocked with pressurizer pressure in such a way that the blocking action is automatically removed above a preset pressure as operating pressure is approached. If two-out-ot-three pressure signals are above this preset pressure, blocking action cannot be initiated. The block condition is annunciated in the control room.

For starting pump and fan motors, the slave relays, when energized, cause closing coils on the motor starters or circuit breakers to be energized. When motor starters are used, the starter operating coil is supplied by power from the same source as the subject motor.

When circuit breakers are used for motor control, the circuit breakers close and trip coils are supplied by power from a 125 volt dc battery bus as outlined in Section 8.

Air actuated solenoid piloted containment vent and purge isolation valves are spring loaded to close upon loss of air pressure.

7.4.2.5 Inspection and Testing

The analog instrumentation associated with the Engineered Safety Features Actuation System is tested in the same manner as the reactor protection system described in Section 7.4.1.4.4. The logic channel testing is also similar to that of the reactor protection system as described in Section 7.4.1.4.6.

In general, Engineered Safety Features master relays (actuated by the logic) are tested at power while the slave relays are blocked. Actuating coils of the slave relays are checked for continuity. However, not all ESF circuits are designed and tested in this manner.

During plant shutdown, the master relays are actuated, actuating the slaves, which are allowed to start the safety injection sequence. The test is terminated when associated valves are properly aligned and associated pumps are started.

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7.5 PLANT RADIATION MONITORING SYSTEM

7.5.1 General Summary and Description

The Radiation Monitoring System is designed to reliably provide the information required to meet the following four functions:

a. Warn operating personnel of potential radiological health hazards which have developed.

b. Give early warning of certain plant malfunctions which might lead to a radiological health hazard or plant damage.

c. Prevent or minimize the effects of inadvertent release of radioactivity to the environment by consequence limiting automatic responses.

d. Provide routine monitoring of controlled offsite plant releases.

The ranges and sensitivities of the individual channels are consistent with meeting the requirements of 10CFR20, 10CFR50 and 10CFR70. The channel electronics are of fail safe design such that a channel failure will cause an alarm. Channel failures are alarmed and indicated at the corresponding Radiation Monitoring System Panels, on a common alarm on the Miscellaneous Plant Annunciator Panel, or on ERCS.

Radiation monitoring instruments are of nonsaturating design that preclude fall off in indication in high radiation fields. Where required, uninterruptable power is provided from safeguards sources. Redundant to each other, channels are isolated electrically and physically. Redundant channels have independent power sources. Each channel is subject to a minimum 10 hour electrical burn in period by the supplier. 00-290

00-290

The components of the Radiation Monitoring System are designed according to the following environmental conditions:

a. Temperature - as described in Table 7.5-1. 00-290

b. Humidity - 0 to 95% relative humidity

c. Pressure - Detectors and sampling units are designed to function under process stream pressures during both normal and accident conditions. Monitors in the control room are designed for normal atmospheric pressure. 00-290

d. Radiation - Process and area radiation monitors are of a nonsaturating design so that they "peg" full scale if exposed to radiation levels at over full scale intensities. Critical process monitors are located in areas where the normal and post-accident background radiation levels will not affect their usefulness.

A primary calibration was performed on a one time basis in the vendor's "Design Verification Tests", which utilized typical isotopes of interest to determine proper detector response. Further primary calibrations were not required since the geometry could not be significantly altered within the sampler. Calibration of samplers was then performed based on a known correlation between the detector responses and a secondary standard.

Secondary standard calibrations were performed with a radiation source of known activity. This single point calibration confirmed the channel sensitivity. The secondary standard calibration was performed by removing the detector and placing the check source on the sensitive area of the detector.

The Radiation Monitoring System is divided into the following subsystems:

a. The Process Radiation Monitoring System monitors various fluid and air streams for indication of increasing radiation levels. (see Section 7.5.2) 00-290

b. The Area Radiation Monitoring System monitors in various areas of the plant. (see Section 7.5.3) 00-290

c. The Environmental Radiation Monitoring System monitors radiation in various areas surrounding the plant (see Section 2.7).

7.5.1.1 Monitoring Radioactivity Releases

GDC-17 Means shall be provided for monitoring the containment atmosphere and the facility effluent discharge paths for radioactivity released from normal operations, from anticipated transients, and from accident conditions. An environmental monitoring program shall be maintained to confirm that radioactivity releases to the environs of the plant have not been excessive.

The containment atmosphere, the shield building vent, the auxiliary building vent, the control room ventilation system, the spent fuel pool exhaust, the RHR cubicle ventilation exhaust, the Radwaste Building ventilation exhaust, the condenser air ejector exhaust, the circulating water discharge, the containment fan coolers cooling water discharge (after receipt of an SI signal), blowdown from the steam generators, the component cooling water, and the Waste Disposal System liquid effluent are monitored for radioactivity conditions. High radiation in any of these is indicated and alarmed in the control room.

All gaseous effluent from possible sources of accidental radioactive release external to the reactor containment (e.g., the spent fuel pool and waste handling equipment), except Radwaste Building ventilation, will be exhausted from an auxiliary building vent which is monitored. All accidental spills of liquids are contained within the Reactor Auxiliary Building and collected in a sump. Any contaminated liquid effluent released to the condenser circulating water is monitored. For any leakage from the reactor containment under accident conditions, the plant radiation monitoring system supplemented by portable survey equipment provides adequate monitoring of radioactivity release.

7.5.1.2 Monitoring Fuel and Waste Storage Areas

GDC-18 Monitoring and alarm instrumentation shall be provided for fuel and waste storage and associated handling areas for conditions that might result in loss of capability to remove decay heat and to detect excessive radiation levels.

Monitoring and alarm instrumentation is provided for fuel and waste storage and handling areas to detect deviation from normal water level, inadequate cooling and excessive radiation levels. Radiation monitors are provided to maintain surveillance over the release of radioactive gases and liquids, and the permanent record of activity releases is provided by radiochemical analysis of known quantities of waste.

A controlled ventilation system moves air from the atmosphere of the fuel storage and waste treating areas of the auxiliary building and discharges it to the atmosphere via an auxiliary building vent. Radiation monitors on these effluent paths are in continuous service and will actuate high radiation alarms on the control board annunciator, as described in Section 7.5.2. 00-290

7.5.1.3 Protection Against Radioactivity Release from Spent Fuel and Waste Storage Areas

GDC-69 Provisions shall be made in the design of fuel and waste storage facilities such that no undue risk to the health and safety of the public could result from an accidental release of radioactivity.

All waste handling and storage facilities are contained and equipment is designed so that accidental releases directly to the atmosphere are monitored and will not exceed the guidelines of 10CFR100, as discussed in Sections 9 and 14.

7.5.2 Process Radiation Monitoring System

Process monitor detectors are located in the process stream such that they are not subjected to temperatures in excess of maximum specified detector operating temperatures. 00-290

The process monitor channels are designed to provide information on:

a. Radioactivity concentration levels present in the various systems.

b. Leakage across boundaries of closed systems. 00-290

c. Radioactivity concentrations in liquid and gaseous effluent paths that lead to release from the plant site.

Where required, radiation monitoring channels are capable of initiating alarms and actuating control equipment to assure confinement of radioactive materials if pre-established limits are exceeded. 00-2

Check, test, and calibration frequencies for the process radiation monitoring system channels are specified in the Offsite Dose Calculation Manual. 00-290

7.5.2.1 General

This system consists of channels which monitor radiation levels in various plant operating systems. The output from each channel detector is transmitted to the Radiation Monitoring System cabinets located in the control room area where the radiation level is indicated by a meter and recorded by ERCS. High radiation level alarms are annunciated in the control room and identified on the Radiation Monitoring System panel. Table 7.5-1 provides further details concerning the detector type, range of operation and sensitivity of each monitor. 00-290

Each channel contains a completely integrated modular assembly, which includes the following:

a. Level Amplifier/Discriminator

   Amplifies and discriminates the detector output pulse to provide a discriminated and shaped pulse output to the log level amplifier.

b. Log Level Amplifier

   Accepts the shaped pulse of the level amplifier output, performs a log integration, (converts total pulse rate to a logarithmic analog signal) and amplifies the resulting output for suitable indication and recording.

c. Power Supplies

   Individual power supplies are contained in each drawer for furnishing the positive and negative voltages for the transistor circuits, relays and alarm lights and for providing the high voltage for the detector.

d. Test-Calibration Circuitry

   Selected monitors have circuits which provide a precalibrated pulsed and/or analog signal to perform channel test. An annunciator light on the main control board indicates when any channel is in the test calibrate mode. 00-290

e. Radiation Level Meter

   This meter, mounted on the assembly drawer, has a scale calibrated logarithmically in counts per minute in various ranges. Specific monitors have both a wide and narrow range meter to provide better readability.

f. Indicating Lights

These lights indicate high radiation alarm levels and circuit failure. An annunciator on the main control board is actuated on high radiation signal and another annunciator is actuated on circuit failure.

g. Alarm Circuits

Three alarm circuits are provided, one to alarm on high radiation (actuation point may be set at any level over the range of the instruments), one to alarm on loss of signal (circuit failure). Selected monitors also have an alarm for sampling systems malfunctions. 00-290

h. The Process Radiation Monitoring system consists of the following radiation monitoring channels (the prefix numbers, where used with channel identification, indicate monitors associated with Unit No. 1 or No. 2).

7.5.2.1.1 Effluent Monitoring

The plant release paths for liquid and gaseous effluents together with their associated monitoring instrumentation are provided in the following tabulation:

Discharge Path	Radiation Monitors
Auxiliary Building Vent Unit 1 and Unit 2	Auxiliary Building Vent Monitors A & B, Channels 1R-30, 2R-30, 1R-37 and 2R-37.[1]
Shield Building Vent	1. Shield Building Vent Monitors, Channels 1R-22 and 2R-22. [1] 2. Containment or Containment Purge Vent-Air Particulate Monitors, Channels 1R-11 and 2R-11. 3. Containment or Containment Purge Vent-Radioactivity Gas Monitors, Channel 1R-12 and 2R-12. 4. High Range Shield Building Vent Monitors Channels 1R-50 and 2R-50
Waste Disposal System Liquid Effluent Discharge Line	Waste Disposal System Liquid Effluent Monitor, Channel R-18
Steam Generator Secondary Side	1. Steam Generator Blowdown System Liquid Sample Monitors, Channels 1R-19 and 2R-19. 2. Condenser Air Ejector Gas Monitor, Channels 1R-15 and 2R-15. [2]
Radwaste Treatment Building Vent	Radwaste Treatment Building Vent Monitor, Channel R-35.
Spent Fuel Pool Normal Ventilation System Weather Cap	Spent Fuel Pool Air Monitors A&B, Channels R-25 and R-31.

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1 Includes particulate and charcoal integral sampling system.

2 In addition to the Monitors listed, secondary samples are taken routinely for analysis in the counting room. The condenser air ejector discharges to the Auxiliary Building Ventilation Systems and also is monitored by the Aux Bldg Stack Monitors and Shield Building Stack Monitors.

Section 9.1 provides a detailed discussion of the collection and processing capability of the waste disposal system. All releases resulting from routine plant operations are made on a batch basis. These include containment purge, gas decay tank purge, and liquid waste disposal system releases. The potential also exists for very low level releases of gaseous and liquid contaminants resulting from minor leakage paths (e.g. reactor coolant processing equipment; steam generator tube leaks). The following operational procedures are observed to assure the proper detection, measurement, and control of the plant effluent releases.

The release of liquid wastes is managed on a batch basis. The waste is collected in tanks. The tank is isolated and sampled after a reasonable amount has been collected. The batch will be either processed, recycled, or discharged based on the results of the lab analysis of the sample. If the batch is to be discharged, the in-line radiation monitor is a backup to the lab analysis. The waste discharge rate is controlled according to the lab analysis and dilution available. The flows are adjusted to result in the average activity limits in the diluted stream. The radiation monitor is set at an activity level which would result in the instantaneous limit in the diluted stream. If the higher limit is reached the monitor automatically initiates closure of the discharge valve in the waste stream.

The discharge limits are those stated in 10CFR20 and Appendix I to 10CFR50. The samples are analyzed frequently at the start of plant operation to identify the isotopic content and then periodically to verify that the constituents have not changed. Information on the isotopic content of the waste stream is forecast by the ODCM.

a. Non-Batch Releases

1. Gaseous

These releases are monitored by the Auxiliary Building Vent Gas Monitors Both of these channels have a functional alarm level set per the ODCM. A routine laboratory analysis is made of the gaseous, halogen, and particulate constituents in the release stream. Integrating samplers are provided to enhance the detection sensitivity.

Possible sources that could contribute to these discharge paths are Steam Generator Blowdown, containment purge, leakage from gaseous storage, condenser offgas, and atmospheric steam dump during plant transients. Monitoring of these paths is considered throughout Sections 7.5.1 and 7.5.2.

2. Liquid

   These releases are monitored by either the Steam Generator Blowdown Liquid Monitor or the Circulating Water Discharge Monitor. The Steam Generator Blowdown Liquid Monitor functional alarm level is set by the ODCM. Routine laboratory analyses are performed that will account for at least 90% of the gross activity and provide the short-lived to long-lived activity ratio.

   The Steam Generator Blowdown Monitor provides for automatic discharge valve closure on high alarm as described in Section 7.5.2.13.

7.5.2.2 <u>Containment or Containment Purge Vent - Air Particulate Monitor (1R-11 and 2R-11)</u>

These monitors are provided to measure air particulate gamma radioactivity in the containment and to ensure that the release rate through the containment purge vent during purging is maintained below specified limits. In the containment sampling mode, it also provides quality information on incipient primary system leaks.

This channel takes a continuous air sample from either the containment atmosphere, or the containment purge vent ductwork through a closed, sealed system monitored by a filter paper and detector assembly. The filter paper collects 99% of all particulate matter greater than 1 micron in size on its constantly moving surface, and is viewed by a detector. The filter paper is not charcoal impregnated and is not designed to detect gaseous forms of radioactivity. The sample is returned to the vent after it passes through the series connected (R-12) gas monitor. 00-290

The detector assembly is in a completely enclosed housing. The pulse signal is transmitted to the Radiation Monitoring System panels in the control room. Lead shielding is provided to reduce the background level to where it does not interfere with the detector's sensitivity. 00-290

The filter paper mechanism, an electro-mechanical assembly which controls the filter paper movement, is provided as an integral part of the detector unit. The filter paper has a nominal 25 day minimum supply at normal speed. 00-290

See section 7.5.2.3 for more information on these monitors. 00-290

7.5.2.3 Containment or Containment Purge Vent Radioactivity Gas Monitor (1R-12 and 2R-12)

These monitors are provided to measure gaseous radioactivity in the containment, and to ensure that the radiation release rate during purging is maintained below specified limits. High gas radiation level initiates closure of the containment purge supply and exhaust duct valves for containment purge and inservice purge systems.

00-290

This channel takes the continuous air sample from the containment atmosphere or the purge vent after it passes through the air particulate monitor, and draws the sample through a closed, sealed system to the gas monitor assembly. The sample is constantly mixed in the fixed, shielded volume, where it is viewed by a detector. The sample is then returned to the Auxiliary Building Ventilation system. 00-290

The detector assembly is in a completely enclosed housing containing a β - γ sensitive Geiger-Mueller tube mounted in a constant volume gas container. Lead shielding is provided to reduce the background level to a point where it does not interfere with the detector's sensitivity. The detector output is transmitted to the Radiation Monitoring System panels in the control room.

The installed air particle monitor (R-11) and the radioactivity gas monitor (R-12) are designed to detect the minimum concentrations of the isotopes of interest and, in monitoring gross activity, they are designed to generate an alarm under abnormal conditions. Isotopic identification and concentrations are determined by grab sample analysis. If either R-11 or R-12 measures activity greater than the setpoints, then a containment vent isolation signal is initiated. This closes the Containment Purge Supply and Exhaust Dampers.

The containment radioactive gas monitor is inherently less sensitive than the containment air particulate monitor, and would function in the event that significant reactor coolant gaseous activity exists from fuel cladding defects. Assuming a reactor coolant activity of 0.3 $\mu c/cc$, the occurrence of a leak of two to four gpm would double the zero leakage background in less than an hours time. In these circumstances this instrument is a useful backup to the air particulate monitor. 00-290

The Containment Air Particulate and Radioactivity Gas Monitors (R-11 and R-12) have assemblies common to both channels. They are described as follows:

a. The flow control assembly includes a pump unit and selector valves that provide a representative sample (or a "clean" sample) to the detector.

b. The pump unit consists of:

   1. A pump to obtain the air sample.

   2. A flowmeter to indicate the flow rate.

   3. A flow control valve to provide flow adjustment.

   4. A flow alarm assembly to provide low and high flow alarm signals.

c. Selector valves are provided to direct the desired sample to the detector for monitoring and to block flow when the channel is in maintenance or "purging" condition.

d. A pressure sensor is provided to protect the system from high pressure transients. This unit automatically closes the inlet and outlet valves upon a high pressure condition.

e. Purging is accomplished with a valve control arrangement whereby the normal sample flow is blocked and the detector purged with a "clean" sample. This facilitates detector calibration by establishing the background level and aids in verifying sample activity level.

f. The flow control panel in the control room radiation monitoring racks permits remote operation of the flow control assembly. By operating a sample selector switch on the control panel, either the containment or the containment purge vent sample may be monitored.

g. A sample flow rate indicator is calibrated linearly from 0 to 14 cubic feet per minute.

Alarm lights are actuated by the following:

a. Flow alarm assembly (low or high flow)

b. The pressure sensor assembly (high pressure)

c. The filter paper sensor (paper drive malfunction)

d. The pump power control switch (pump motor on)

7.5.2.4 Shield Building Vent Gas Monitor (1R-22 & 2R-22)

In addition to the flexibility of utilizing R-11 and R-12 for monitoring the Shield Building Vent, another channel is also provided. An isokinetic nozzle is provided for sample collection. This channel consists of a particulate filter, charcoal filter and off-line type radioactivity gas monitor mounted in series. This channel continuously monitors the filtered effluent in the Shield Building Vent for activity. The gaseous detector is a large area type mounted in an off-line sampler. 00-290 The sample tank design provides a cyclonic air flow around the detector axis to preclude stagnancy within the sensing volume. The detector output is transmitted to the Radiation Monitoring System panels in the control room.

The particulate and charcoal filter are used to determine the activity of particulates and halogens in the effluent stream. 00-290 This radiation monitoring equipment is not suitable for determining on-line post-accident effectiveness of the HEPA and charcoal filters.

Post accident ventilation of the Auxiliary Building is made via the Auxiliary Building special ventilation system to the Shield Building vent. An additional sample line has been routed to the Turbine Building equipped with a particulate and silver zeolite filter and also with a sample chamber (7.5.2.18).

When a high radiation condition is detected, a containment vent isolation signal is initiated which closes the containment purge supply and exhaust valve for the containment purge and inservice purge systems. 00-290

7.5.2.5 Auxiliary Building Vent Gas Monitor (1R-30, 2R-30, 1R-37, 2R-37)

The auxiliary building vent gas monitor detects radioactivity passing through the auxiliary building vent. It is essentially identical to that discussed for channel R-22.

A high level alarm initiates isolation of the Auxiliary Building Normal Exhaust, ensures the gas decay tank vent valve closes if it is open, and actuates the Auxiliary Building Special Ventilation.

00-290

7.5.2.6 Condenser Air Ejector Gas Monitor (1R-15 and 2R-15)

This channel monitors the discharge from the condenser air ejector exhaust header of the condensers for gaseous radioactivity which is indicative of a primary to secondary system leak. The gas discharge is routed to the Auxiliary Building Normal or Special Ventilation Systems.

A beta and gamma sensitive detector is used to monitor the gaseous radioactivity concentration. 00-290 The detector is inserted in an in-line fixed volume container which includes adequate shielding to reduce the background radiation so that it does not interfere with the detectors maximum sensitivity. 00-290

The detector output is transmitted to the Radiation Monitoring System panels in the control room. The activity is indicated by a meter and recorded by ERCS. High-activity alarm indications are displayed on the control board annunciator in addition to the Radiation Monitoring panels.

7.5.2.7 Control Room Ventilation Monitor (R-23 and R-24)

This system consists of two identical channels that monitor the control room supply air for an indication of airborne activity entering the control room. A high level alarm is annunciated in the control room to alert operators of an abnormal condition. Each monitor also automatically starts its associated control room clean-up fan and isolates the control room from outside air. (See section 10.3.3 for details.) 00-290

Readout is in the control room on the radiation monitoring system panels including a rate meter. 00-290

7.5.2.8 Spent Fuel Pool Air Monitor (R-25 and R-31)

These channels monitor the pool sweep air handling system for any indication of fuel leakage gases or mechanical failures from handling operations during the storage period. A high sensitivity detector is located in the exhaust duct in proximity to the spent fuel pool.

A high level alarm annunciates in the pool area and control room, isolates the Spent Fuel Normal Ventilation Supply and Exhaust Dampers, shuts down the Containment In-service Purge System and actuates the Spent Fuel Special Ventilation System which exhausts the Spent Fuel Pool area air through a PAC filter.

The detector output is also transmitted to the radiation monitoring system panels in the control room. 00-290

7.5.2.9 Residual Heat Removal Cubicle Air Monitor (R-26 and R-27)

A radiation monitoring system capable of detecting a 1 gpm leak in the out of containment portion of the RHR system during a design basis accident is provided by the use of redundant monitors which sample the special ventilation system exhaust from the RHR cubicles. During conditions in which the auxiliary building special ventilation system is actuated, the ventilation ducts from the RHR cubicles are continuously monitored for any indication of system leaks.

A high sensitivity detector is mounted in an off-line sample volume chamber. A high level alarm is annunciated in the control room to alert operators of an abnormal condition.

7.5.2.10 Containment Fan Cooling Water Monitors (R-16 and R-38)

During a loss of coolant accident, these channels monitor the containment fan cooling water for radioactivity indicative of a leak from the containment atmosphere into the cooling water. A small bypass flow from each of the heat exchangers is mixed in a common header and monitored by a single detector mounted in a holdup tank assembly. For R-16 lead shielding is provided to reduce the background level so it does not interfere with the detector's sensitivity. Upon indication of a high radiation level, each heat exchanger is individually isolated to determine which unit is leaking. The leaking fan coil unit is left isolated from the cooling water line.

7.5.2.11 Component Cooling System Liquid Monitor (1R-39 and 2R-39)

These channels continuously monitor the Component Cooling System for radioactivity indicative of a leak of reactor coolant from the Reactor Coolant System and/or the Residual Heat Removal System as well as other sources. A detector is located in an offline well which is tied into the component cooling heat exchanger outlet header.

Output of the monitor is amplified by a preamplifier and transmitted to the Radiation Monitoring System panels in the control room. The activity is indicated on a meter and recorded on ERCS. High-activity alarm indications are displayed on the control board annunciator and the Radiation Monitoring System panels. A high-radiation level alarm signal initiates closure of the valve located in the component cooling surge tank vent line to prevent gaseous radiation release.

7.5.2.12 Waste Disposal System Liquid Effluent Monitor (R-18)

This channel continuously monitors all Waste Disposal System liquid releases from the plant. Automatic valve closure action is initiated by this monitor to prevent further release after a high radiation level is indicated and alarmed. A detector located in an inline sample tank assembly monitors these effluent discharges. Lead shielding is provided to reduce the background level so it does not interfere with the detector's sensitivity. Remote indication and annunciation are provided on the Waste Disposal System control board.

7.5.2.13 Steam Generator Blowdown System Liquid Monitor (1R-19 and 2R-19)

This channel monitors the liquid phase of the secondary side of the steam generator for radioactivity, which would indicate a primary to secondary system leak, providing backup information to the condenser air ejector gas monitor. The radiation monitor is located on the liquid discharge line from the blowdown flash tank downstream of the blowdown heat exchanger. Steam generator blowdown (SGBD) from both steam generators is mixed in the flash tank. Steam generator blowdown is continuously monitored by a detector in the radiation monitor assembly. If high activity is indicated from the blowdown radiation monitor, each steam generator can be individually sampled via the sample system to determine the source of the primary to secondary leak. This sampling sequence is achieved by manually selecting the desired unit to be monitored and allotting sufficient time for sample equilibrium to be established (approximately 1 minute). 00-290

The detector, which is mounted in a hermetically sealed unit, is used to monitor liquid effluent activity. Lead shielding is provided to reduce the background level so it does not interfere with detector sensitivity. The inline, fixed volume container is an integral part of the detector unit. 00-290

A high radiation signal from the blowdown radiation monitor closes the blowdown flash tank inlet control valves, closes the blowdown river discharge control valve, indicates high radiation in the main control room, and alarms at the auxiliary building operator station liquid waste panel.

00-290

7.5.2.14 Circulating Water Monitor (R-21)

This channel provides continuous final monitoring of the discharge canal effluent prior to river dispersal. It provides direct measurement of the diluted plant effluent concentration and serves as a redundant system measuring the various streams feeding the discharge canal, except for the Waste Liquid Discharge Header. The Waste Liquid Discharge Header is extended to the end of the discharge canal to a point just upstream of the river release sluice gates. This line effectively bypasses R-21, however, redundant monitoring is provided for all types of liquid releases as detailed in the following two paragraphs.

Steam generator blowdown releases are monitored by either 1R-19 or 2R-19 before entering the Waste Liquid Discharge Header. Also, periodic samples of SGB releases to the river are analyzed.

All other radioactive liquid waste water is sampled and analyzed before initiating any release to the river. During such releases, R-18 monitors radioactivity in the waste liquid discharge line before it leaves the Auxiliary Building. This monitor will stop the release if activity exceeds the expected range.

A hermetically sealed detector is inserted in the sample volume. Lead shielding is provided to reduce the background level so it does not interfere with the detector's sensitivity. A high level alarm is annunciated in the control room. 00-290

7.5.2.15 Radwaste Building Vent Monitor (R-35)

This channel monitors the beta-gamma activity in the effluent gases emitted through the exhaust stack. The gaseous detector is a large area type mounted in an off-line sampler. The sample tank design provides a cyclonic air flow around the detector axis to preclude stagnancy within the sensing volume. 00-290

A remote indicator panel mounted at the detector location indicates the radiation level and provides a high radiation alarm. 00-290

7.5.2.16 Waste Gas High Activity Loop Inventory Monitor (R-41)

This channel monitors the gamma activity of the High Activity Waste Gas Loop. The detector is inserted in an in-line fixed volume container which includes adequate shielding to reduce the background radiation so that it does not interfere with the detectors maximum sensitivity. A high level alarm annunciator is provided in the Control Room. 00-290

7.5.2.17 Deaerator Liquid Monitor (R-42)

This channel monitors the gamma activity of the Heating Boiler Deaerator liquid.

The Heating Boiler Deaerator serves as a collection point for all the Heating Steam Condensate. A detector is located in an offline well. Lead shielding is provided to reduce the background level so it does not interfere with the detector's sensitivity. A high radiation alarm from this channel is indicative of a Radioactive Waste Evaporator tube leak. 00-290

7.5.2.18 High Range Shield Building Vent Gas Monitor (1R-50, 2R-50)

The high range shield building vent stack monitors are located in the Turbine Building due to the possibility of high dose rates in the Auxiliary Building during a major plant accident.

Two sets of shielded particulate filters and iodine absorbers are used to collect representative samples. An isokinetic nozzle is provided for sample collection. One set of particulate filter and iodine absorber has a flow rate of between 1 to 3 cfm which is used during normal operation and during an accident when the particulate and iodine activity release levels are low. The second set of particulate filter and iodine absorbers has a flow rate of 10cc/min +/-25% and would be used during accidents when the particulate and iodine release activities are very high. 00-290 Silver zeolite is used as the iodine absorber because of its very low absorption rate for gases which would mask the detection capabilities of iodine.

The radio gas detectors for R-50 monitors view a very large sample chamber. The monitors are powered from the Safeguards Electrical System and readout and alarm in the Control Room. 00-290

7.5.2.19 Steam Line Radiation Monitors (1R-51, 2R-51, 1R-52, 2R-52)

The steam line radiation monitors are located in the Auxiliary Building of both units with one monitor on each steam loop. The monitors readout in the Event Monitoring room and have outputs to ERCS. The purpose of the steam line monitors and ERCS is to quantify steam activity release and release rates from the steam safeties, reliefs, dumps and auxiliary feed water pumps. The monitors and ERCS receive power from the ERCS uninterruptable power supply system. The ERCS provides alarm and trending functions for the monitors. The monitors are displayed as part of the SPDS.

These radiation monitors were not part of the original plant design and construction. Therefore, they do not conform to the channel descriptions found in section 7.5.2.1 of the USAR. These monitors were installed in response to RG 1.97 and conform to the applicable requirements discussed in section 7.10.2 of the USAR.

7.5.3 Area Radiation Monitoring System

The area monitoring channels are designed to provide information of a general operational nature useful in assessing radiation exposures to personnel. Fixed position detectors are located in areas that have a high radiation and/or occupancy potential during both normal and abnormal plant operations. Usually, an indicator-alarm station is mounted adjacent to an area monitor detector. In some cases, such as the new Fuel Pit Criticality Monitor, the detector is located in an inaccessible location. For these channels the indicator alarm assembly is installed in an accessible location as close as possible to the detector.

Components of this system which are located in containment are the detectors for low and high range area monitoring channels. The low range area monitors are not expected to operate following a major loss of coolant accident and are not designed for this purpose. The high range containment monitors are designed to operate following a major loss of coolant accident. See section 7.10.3.6.

7.5.3.1 General

00-290

This system consists of channels which monitor radiation levels of various areas of the plant. These areas are as follows:

Channel	Area Monitor
R-1	Control Room
R-2	Containment (each unit)
R-3	Radiochemistry Laboratory
R-4	Charging Pump Room (Unit 1)
R-5	Spent Fuel Area
R-6	Sampling Room
R-7	Incore Seal Table (each unit)
R-8	Waste Gas Valve Gallery
R-9	Reactor Coolant Letdown Line (each unit)
R-28	New Fuel Pit Criticality Monitor
R-29	Shipping and Receiving
R-32	Rad Waste Building 2nd Floor
R-33	Rad Waste Building Control Station
R-36	Charging Pump Room (Unit 2)
R-48	High Range Containment Area Monitor Train B (each unit)
R-49	High Range Containment Area Monitor Train A (each unit)
R-53	Safety Injection Pump Area Monitor
R-54	Containment Spray Pumps Area Monitors
R-55, R-56	Auxiliary Building 695 Level Area Monitors
R-57, R-58	Auxiliary Building 715 Level Area Monitors
R-59	Auxiliary Building 715 Letdown/Penetration Area Monitors
R-60	Auxiliary Building 735 Level Area Monitors
R-61	Loop A Steam Line Area Monitors
R-62, R-63	Auxiliary Building 755 Level Area Monitors
R-64	Turbine Building 735 Level Area Monitors
R-65	Operational Support Center Area Monitor
R-66	D-1 Diesel Generator Room Area Monitor
R-67	Instrument and Control Shop Area Monitor
R-68	Technical Support Center Area Monitor
R-69	Guardhouse Area Monitor
R-72	D-6 Cable Spreading Room Area Monitor
R-73	Bus 26 Switchgear Room Area Monitor
R-74	480V Bus 221 and 222 Switchgear Room Area Monitor

00-290

Table 7.5-1 provides further details concerning the detector type, range of operation and sensitivity of each monitor.

Each channel consists of the following features:

a. Amplifier

The detector output is amplified and the log count rate is determined by the integral amplifier at the detector.

b. Indication

The indicator module amplifies the radiation level signal, as computed by the log level amplifier, for indication and recording. The radiation level is indicated locally at the detector, and at the Radiation Monitor System panels in the Control Room or Drive Rooms.

A meter is mounted on the front of each indicator module and is calibrated logarithmically from 0.1 mrem/hr to 10 rem/hr for channels R-1 through R-9 and from 1 mrem/hr to 100 rem/hr for channel R-28. For channels R-53 through R-69, and R-72 through R-74, the readout units have a digital readout and an analog bar graph to provide indication from 0.1 mR/hr to 1×10^7 mR/hr.

A remote meter, with an equivalent range for each monitor is mounted at each detector assembly.

c. Alarms

High radiation alarms are displayed on the Radiation Monitoring panels in the control room at the detector location and on the main control panel. Verification of which channel has alarmed is made at the radiation monitoring system panels.

Radiation Monitoring System Panel alarms consist of a red indicator light for high radiation. The remote meter and alarm assembly contains a red indicator light and an audible alarm actuated on high radiation. Selected monitors have a yellow light to annunciate detector or circuit failure or loss of power.

d. Recording

Selected radiation monitors are available for viewing or trending on ERCS.

e. System Racks and Panels

All of the equipment for monitors R-1 through R-50 are centralized in four racks in the control room. High reliability and ease of maintenance are emphasized in the design of this system. Rapid replacement of units, assemblies and entire channels is possible. It is also possible to completely remove the various chassis from the cabinet, after disconnecting the cables from the rear of these units. 00-290

Monitors R-53 through R-69 and R-72 through R-74 are installed in racks in the Control Rod Drive Rooms.

7.5.3.2 Description

7.5.3.2.1 Reactor Coolant Letdown Line Monitors (1R-9, 2R-9) 00-290

The Reactor Coolant Letdown Line Monitor (R-9) is used for detection of fuel element failures. See section 10.2.3.3.7 for additional information on the fuel element failure detection system.

7.5.3.2.2 New Fuel Pit Criticality Monitor (R-28) 00-290

The new fuel pit criticality monitor (R-28) is an area radiation monitor. The gamma sensitive detector is located in a new fuel pit approximately 3′ below the refueling floor which places it slightly below the top of the stored fuel. The associated local meter is mounted on a wall of the fuel pool enclosure 7′ feet above the floor. The monitor is set to alarm in the range of 5 to 20 mrem/hr. Besides actuating an alarm in the Control Room, the new fuel pit criticality monitor actuates a special evacuation alarm in the fuel pit area. The monitor has been installed in accordance with the requirements of 10CFR70.24.a.2. 01-08000-290

7.5.3.2.3 High Range Containment Monitors (1R-48, 1R-49, 2R-48, 2R-49) 00-290

The high range containment radiation monitoring system (R-48, R-49) is designed to provide in containment high level monitoring capabilities during accident conditions. The system is Class 1E. The detector assembly is gamma sensitive and encased in stainless steel. The system, consists of a detector, readout module and cabling for each train, meets all requirements of NUREG-0578 Item 2.1.8.b and NUREG-0737 Item II.F.1.3. These monitors are designed to withstand containment test pressure. 01-080 00-290

7.5.3.2.4 Wide Range Area Monitors

The wide range area monitors, channels R-53 through R-69, and R-72 through R-74, are designed to provide radiation exposure rate indication inside buildings and areas where access is required to service equipment important to safety. These monitors were installed in response to Reg Guide 1.97. The channels consist of the detector, remote indicating alarm/pre-amp, readout units and interconnecting cabling. The detector is gamma sensitive.

7.5.3.3 Performance Analysis

Table 7.5-1 provides a listing of the Radiation Monitoring System channels, containing sensitivities and ranges. This table also indicates the detector condition during normal operation. Where fluid temperature is too high for the monitor, a cooling device with temperature indication is included. The different operating temperature ranges are within the design limits of the sensors.

The relation of the radiation monitoring channels to the systems with which they are associated is given in the sections describing those systems.

7.5.4 Health Physics and Laboratory Radiation Measuring Instrument

7.5.4.1 Design Basis

Portable radiation survey instruments are available for the measurement of the alpha, beta, gamma and neutron radiation expected in normal operation and emergencies. Appropriate instruments and auxiliary equipment are available to detect and measure radioactive contamination on surfaces, in air, and in liquids.

7.5.4.2 Personnel Monitoring

The official and permanent record of accumulated external radiation exposure received by individuals is obtained principally from the interpretation of the thermoluminescent dosimeter. A direct reading dosimeter and indirect reading dosimeter provides continuous indication of external radiation exposure.

All persons required by 10CFR20 to be monitored for radiation exposure are issued a thermoluminescent dosimeter and a direct reading dosimeter prior to entry into a Radiation Control area. The thermoluminescent dosimeters are replaced and processed at a predetermined interval. Special or additional monitoring devices are issued at the discretion of radiation protection personnel.

Whole body counting will be conducted for persons with suspected internal contamination or at the discretion of radiation protection personnel. Bioassays such as urine analysis are not planned to be conducted on a routine basis but rather only specific cases of special operations which may warrant such analysis. Records of personnel exposures are maintained and reported in accordance with the requirements of 10CFR20. Additionally, special reports of abnormal exposures incidents are submitted pursuant to 10CFR20.

As a general program of exposure control, the Radiation Protection Group conducts routine plant surveys for direct radiation levels, smearable contamination, and airborne levels. These routine and special surveys are used to establish radiation area information and the requirements of radiation work permits.

7.5.4.3 Radiation Instrumentation

Laboratory facilities are provided for the radiation protection and chemistry group. These facilities include laboratory, counting room, and radiation protection office. Adequate equipment is provided for radiochemistry analysis, contamination control, and air sample analysis. Portable radiation survey instruments, respiratory protection equipment, and contamination control equipment are maintained at these facilities for use by the Plant Staff.

The type of portable radiation survey instruments and the minimum number of each available for routine monitoring functions are listed in Table 7.5-3.

7.5.5 Performance Analysis

The whole body gamma dose in the control room under accident (LOCA) conditions is discussed in section 14.9.

To determine the possible dose that an operator could receive under accident conditions while operating a manual backup item (e.g., valve), it is estimated rather conservatively that it will require 15 minutes to operate the valve. In addition, it is assumed that an additional 15 minutes is required to get to and from the manual equipment. The total integrated whole body dose that an operator would receive while performing the above operation would be about 8 Rem and is well within the emergency exposure guidelines of NCRP Report 39.

This dose is calculated at one half hour following the accident and assumes that the equipment being operated or serviced is adjacent to the shield building. Doses in the vicinity of equipment located within the auxiliary building would be much less due to the shielding afforded by intervening walls and structures in the auxiliary building.

Following the initiation of the recirculation mode of operation during mitigation of a loss of coolant accident, it should not be necessary to enter the Auxiliary Building in the vicinity of the recirculation piping or components.

The halogen dose to operators in the control room during the course of a loss of coolant accident is minimized by providing a control room ventilation system that automatically isolates all incoming air and is capable of internal recirculation within the control room. In the event of high radiation levels in the control room or in the presence of an SI signal, makeup air from outside is automatically shut off, and absolute and charcoal filters are placed in service on the recirculating air stream. The control room ventilating fans and cleanup fans are supplied by emergency power.

As required by NUREG-0737, Item II.B.2 a design review of plant shielding requirements was conducted. The design review identified the vital areas of the plant that may unduly limit personnel occupancy during and after a design basis accident (DBA). The review also determine the dose rates to these areas from systems that may, as a result of an accident, contain highly radioactive materials.

7.5.6 Inspection and Testing

Periodic testing is performed on all monitors in the Radiation Monitoring System. Testing for response and alarms are made by using a point source. Monitors at effluent release points are calibrated and tested in accordance with the Offsite Dose Calculation Manual.

7.6 INCORE INSTRUMENTATION

7.6.1 Design Basis

The incore instrumentation is designed to yield information on the neutron flux distribution and fuel assembly outlet temperatures at selected core locations. Using the information thus obtained, it is possible to confirm the reactor core design parameters. The system provides means for acquiring data only, and performs no operational plant control.

7.6.2 Description

The incore instrumentation system consists of thermocouples, positioned to measure fuel assembly coolant outlet temperature at pre-selected location; and flux thimbles, which run the length of selected fuel assemblies to permit the measurement of the neutron flux distribution within the reactor core. The design calls for 39 thermocouples and 36 flux thimbles. The high pressure seals for the thermocouples and flux thimbles are shown in Figure 7.6-1. The location of the incore thermocouples is shown in Figure 7.6-4.

The data obtained from the incore temperature and flux distribution instrumentation system, in conjunction with previously determined analytical information, can be used to determine the fission power distribution in the core at any time throughout core life. This method is more precise than using calculational techniques alone. Once the fission power distribution has been established, the maximum power output is primarily determined by thermal power distribution and the thermal and hydraulic limitation which determine the maximum core capability.

The incore instrumentation provides information which may be used to calculate the coolant enthalpy distribution: the fuel burnup distribution; and to estimate the coolant flow distribution.

Both radial and azimuthal symmetry of power distributions may be evaluated by comparing the detector and thermocouple information from one quadrant with similar data obtained from the other three quadrants.

7.6.2.1 Thermocouples

The thermocouple system consists of chromel-alumel thermocouples 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 thermocouple extension cable running from the reactor head mating to the containment penetrations is provided in three sections with quick refueling disconnects. The cabling is a mineral insulated, metal sheathed, multi-conductor thermocouple cable which is both seismically and environmentally qualified.

Fully qualified thermocouple readings are monitored by Emergency Response Computer System and the Inadequate Core Cooling Monitor System. Information from the incore instrumentation is available even if the computer is not in service. The support of the thermocouple guide tubes in the upper core support assembly is described in Section 3.

Incore thermocouple data from the chromel-alumel thermocouples are available from two systems in the control room, the computer and a backup system for manual readout. Core radial power distributions are inferred from the thermocouple data. Periodic computations for relative power are performed in the computer. When properly normalized this system gives a continuous on-line monitor of core quadrant power sharing. The thermocouples were calibrated prior to installation in the new reactor upper internals using a type K thermocouple curve.

A minimum of 4 thermocouples must be operable in the center core region and 1 thermocouple must be operable in each quadrant of the outside core region and each core quadrant must have at least 2 thermocouples operable to ensure that sufficient radial temperature gradient monitoring is provided. See Figure 7.6-4. 01-034

7.6.2.1.1 Normalization Factors

The correction factor to be applied to the thermocouple data serves as a normalization to the radial power sharing. The expression for the Relative Fuel Power (RFP) is

$$RFP_i = \frac{M_i \Delta H_i}{\left[\dfrac{E_{out} - E_{in}}{1 - B} \right]}$$

Where M_i is a normalization factor for channel i, ΔH_i is the enthalpy rise in channel i, and (E(out)-E(in)/(1-B)) is the core average enthalpy rise divided by 1 minus the bypass fraction. The bypass fraction is included to account for that fraction of flow which does not pass through the core. This correction is necessary when the loop bypass RTDs are used to determine the core average enthalpy rise.

The normalization factors M^i are determined from the above equation where the RFP_i represents relative fuel assembly power normalized to 1.0 across the core. In this manner mixing between assemblies is accounted for, along with variations in thermocouple behavior. The assumption is made that one set of factors apply over the normal movement of power and control rods above 50% power. It is felt that ΔT magnitudes are small enough below this level to introduce excessive scatter in the results.

7.6.2.1.2 Power Distributions

The application of normalization factors to the thermocouple RFP values leads to a good prediction of the relative core quadrant power distribution. The results of a study of the positive effects of normalization is shown in Figure 7.6-2. The standard deviation is 3.43% for the example given. 01-037

7.6.2.2 Movable Miniature Neutron Flux Detectors

7.6.2.2.1 Mechanical Configuration

Miniature neutron flux detectors, suitable for the application remotely positioned in the core, provide remote readout for flux mapping. The basic system for the insertion of these detectors is shown in Figure 7.6-3. Retractable thimbles, into which the miniature detectors are driven, are pushed into the reactor core through conduits that extend from the bottom of the reactor vessel down through the concrete shield area, then to a thimble seal table.

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. 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 the refueling to avoid interference during fuel handling. A space above the seal line is provided for the retraction operation.

The drive system for the insertion of the miniature detectors consists of four combinations of drive assemblies, five-path rotary transfer devices, and ten-path rotary transfer devices, as shown in Figure 7.6-3. The drive system pushes hollow helical-wrap drive cables into the core. Miniature detectors are attached to the leading ends of the cables and small diameter sheathed coaxial cables threaded through the hollow centers back to the ends of the drive cables. Each drive assembly consists of a gear motor which pushes a helical-wrap drive cable and detector through a selected thimble path by means of a special drive box which includes a storage device that accommodates the total drive cable length. Further information on mechanical design and support is provided in Section 3.

7.6.2.2.2 Control and Readout Description

The control and readout system provides means to rapidly traverse the miniature neutron detectors to and from the reactor core at seventy-two feet per minute and to traverse the reactor core at twelve feet per minute. The control system consists of two sections: one physically mounted with the drive units, and the other contained in the control room. Each gear box drives an encoder for position indication. One five-path group path selector is provided for each drive unit to route the detector into one of the flux thimble groups or to storage. A ten-path rotary transfer assembly is used to route a detector into any one of up to ten thimbles. Manually operated isolation valves on each thimble allow free passage of the detector and drive cable when open. When closed, these valves prevent leakage from the core in case of a thimble rupture. Provision is made to separately route each detector into a common flux thimble to permit cross calibration of the detectors.

The control room contains the necessary equipment for control, position indication and flux recording. Panels are provided to indicate the position of the detectors, and for plotting the flux level versus the detector position. Additional panels are provided for such features as drive motor controls, core path selector switches, plotting and gain controls. A "flux-mapping" operation consists of selecting (by panel switches) flux thimbles in fuel assemblies at various core locations. The detectors are driven to the top of the core and stopped automatically. An x-y plot from each detector (position vs. flux level) is initiated with the slow withdrawal of the detectors through the core from top to a point below the bottom. All four detectors or any combination of them may be used simultaneously for flux plotting. 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.

7.6.2.2.3 <u>Inspection</u>

By design, the thimble tubes, over most of their length, serve as a portion of the reactor coolant system pressure boundary. Thus, wear of thimble tubes can result in degradation of the reactor coolant system pressure boundary and can also create a potentially non-isolable leak of reactor coolant. As discussed in Reference 40, thimble tubes are experiencing thinning as a result of flow-induced vibration. Thimble tube wear has been identified at several plants, and has generally been detected at locations associated with geometric discontinuities or area changes along the flow path (such as areas near the lower core plate, the core support forging, the lower tie plate, the upper tie plate and the vessel penetration). There have also been several instances of thimble tubes experiencing leaks.

As a result of concerns with the degradation of thimble tubes, the NRC Staff issued NRC Bulletin 88-09 (Reference 41). In NRC Bulletin 88-09, the NRC Staff concluded that the only effective method for determining thimble tube integrity was through plant specific inspections and periodic monitoring. As a result of that conclusion, NRC Bulletin 88-09 required all licensees having Westinghouse designed reactors utilizing bottom mounted instrumentation to implement a formal inspection program that periodically confirms the integrity of the incore neutron monitoring system thimble tubes.

The response to NRC Bulletin 88-09 (Reference 42), described the informal thimble tube inspection program that had in been place since early 1987. Reference 42 committed to formalize the thimble tube inspection program and acceptance criteria per the requirements of Bulletin 88-09 following completion of the Westinghouse Owners Group Bottom Mounted Instrumentation Program. The NRC Staff concluded that the response to NRC Bulletin 88-09 was adequate in Reference 43.

Due to delays in completion of the Westinghouse Owners Group Bottom Mounted Instrumentation Program, Reference 44 notified the NRC Staff that the thimble tube inspection program was being formalized prior to completion of the Westinghouse Owners Group effort. In lieu of Westinghouse Owners Group guidance, the wear criteria and inspection frequency being implemented were the same as the criteria described in Reference 42. Reference 44 also committed to review the results of the Westinghouse Owners Group Program following its completion, and incorporate the results of that study into the thimble tube inspection program as deemed necessary and prudent.

The Westinghouse Owners Group provided guidance on actions required for thimble wear in WCAP-12866, "Bottom Mounted Instrumentation Flux Thimble Wear", January 1991. The information in the WCAP was used to make changes in the formal inspection program based on industry trends developed through the use of both destructive and nondestructive testing. This change was documented in Safety Evaluation Number 335.

7.6.3 Performance Analysis

The thimbles are distributed nearly uniformly over the core, with about the same number of thimbles in each quadrant. 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). Assuming 75% of the thimbles are available, measured nuclear peaking factors will be increased by 5% for F_q and 4% for $F\Delta H$ to allow for measurement uncertainties. Additional measurement uncertainties are required for peaking factor measurements with fewer than 75% of the thimbles available. The minimum number of thimbles required to be operable in any core quadrant is 2. The additional measurement uncertainties for fewer than 75% of the thimbles available are determined, if needed, on a cycle specific basis. The DNB ratio calculated with the measured hot channel factor will be compared to the DNB ratio calculated from the design nuclear hot channel factors.

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7.7 COMPUTER SYSTEMS

7.7.1 Emergency Response Computer System-ERCS

The ERCS collects and processes selected field data for display to plant personnel. This data is displayed in a concise and consistent format on CRT monitors in the Control Room (CR), Technical Support Center (TSC), Emergency Operating Facility (EOF) and Headquarters Emergency Center (HQEC). This information, in its multiple forms is used to assist personnel in the proper implementation of Emergency Procedures during an accident condition covered by these procedures. The system also provides control room personnel with access to relevant information to assist them during operational transients. During normal operation the system provides assistance in determining the status and performance of the core and other plant systems.

The ERCS is designed with a fully redundant backup system for a high degree of availability. A block diagram of the system is presented in Figure 7.7-1.

The ERCS software is composed of the Plant Monitoring System (PMS), the Safety Assessment System (SAS) and the Nuclear Steam Supply System (NSSS) three distinct but fully integrated software packages. All ERCS software has been developed and is maintained under the control of a fully qualified Verification and Validation (V&V) program. 01-029

7.7.1.1 Design Basis

The design criteria for the system is based on the requirements of NUREG-0737, Supplement 1 regarding the need for a Safety Parameter Display System (SPDS) and the upgrading of Emergency Response Facilities. The requirements specified for the SPDS are met or exceeded by a system of displays provided by PMS. The parameters on these displays are provided by the SAS software. The requirements for the upgrading of the Emergency Response Facilities is met by providing ERCS driven CRT monitors in the CR, TSC, EOF and the HQEC.

Regulatory Guide 1.97 information is provided by the ERCS to all the CRT locations.

The Nuclear Steam Supply System (NSSS) application programs satisfy the Plant Process Computer System (PPCS) requirements.

7.7.1.2 Description

7.7.1.2.1 Hardware

The ERCS hardware configuration is designed for high availability. The design utilizes two identical computers for each unit, with automatic failover from primary to backup. Each computer system is fully redundant with it own Central Processing Unit (CPU), disk storage, data concentrator, and redundant input signal paths. An Uninterruptable Power Supply (UPS) and redundant power sources to plant located equipment is also provided.

The inputs to the ERCS, both analog and digital, are obtained from existing instrumentation and control systems. The field inputs are routed to Remote Multiplexor Units (RMUs) where initial signal conditioning is performed. The RMUs and the Fiber Optic Cables to the Data Concentrators provide electrical isolation between the signal source and the ERCS.

Where plant protection circuits are monitored additional isolation is provided. The two types of signals monitored and the method of preventing undesirable interference from these signals are:

a. Analog signals are read into the plant process computer using an analog to digital converter to convert the output DC signal to digital information. The DC voltages scanned by the computer are developed in isolation amplifiers located in the Reactor Protection System. These amplifiers are designed to block any open circuits, short circuits, voltages or currents present in the computer circuitry, from reaching the Reactor Protection System.

b. Reactor protection digital signals are read into the plant process computer from isolated relay or switch contacts in the protection circuitry. Where an isolated set of contacts in protection circuitry is not available for computer use, an interposing relay is added.

The terminals in the Control Room, TSC, EOF, and HQEC have the capability to display, in the available formats, the information contained within the system. A CRT and dedicated keypad located on the Control Room Panel has the capability of selecting any SAS Primary Display by a single key activation. The terminals in the TSC, EOF, and HQEC have the additional capability of being switched to either the Unit 1 or 2 ERCS.

7.7.1.2.2 Plant Monitoring System (PMS) Software

PMS provides the standard scan, log, alarm, display, archival and periodic reporting functions. PMS controls and maintains the ERCS data base. All field inputs, constants, setpoints, and outputs calculated by other applications are contained in this data base. Therefore any of the standard PMS functions can be applied to any point in the system.

PMS performs the following basic functions:

a. Scanning and converting analog signals
b. Scanning contact inputs
c. Alarming
d. Trending analog signals
e. Visual display of input data
f. Pre and post trip review data
g. Sequence of events recording
h. Review of data on a demand basis
i. Sensor calibration information
j. Periodic logs
k. Long, mid and short term archival of data

7.7.1.2.3 Safety Assessment System (SAS) Software

SAS processes all SPDS parameters. SAS performs all necessary calculations, does limit checking and assigns SAS quality codes to each parameter. The processed SPDS parameters are presented on a system of displays called the SAS Primary Displays. There are three types of SAS Primary Displays:

Top Level Displays
Trend Displays
Critical Safety Function (CSF) Tree Displays

The SAS Primary Displays satisfy the SPDS requirements. The SPDS parameters are displayed in multiple forms to assist personnel in the proper implementation of Emergency Procedures during an accident condition and during operational transients. The SAS Primary Displays group the SPDS parameters by system and safety function. Although parameters are displayed in different forms on different displays the value, units and quality are consistent throughout the system.

In response to NRC Generic Letter 89-06, Safety Parameter Display System, the services of an independent contractor were obtained to perform the following activities:

1. Completion of a checklist on the Safety Parameter Display System as required by NRC Generic Letter 89-06,

2. Preparation of photographs and display screen prints of the operational Safety Parameter Display System for both units during power operation in accordance with the photography instructions contained in Generic Letter 89-06 and

3. Review of NUREG-1342 information for applicability to the Safety Parameter Display System implementation.

Based on the results of these activities, the Safety Parameter Display System implemented was found to meet the requirements of NUREG-0737, Supplement 1 (References 33 and 52).

7.7.1.2.4 Nuclear Steam Supply System (NSSS) Software

The NSSS provides plant personnel with concise and reliable information to assist in determining the status and performance of the core. It also provides input to the nuclear fuel performance calculations.

The NSSS performs on-line calculations of data obtained from the reactor control and protection system and the nuclear steam supply system. This data is then displayed in multiple formats to assist personnel in monitoring the operation of these systems.

In addition the NSSS performs secondary plant calculations to assist in the monitoring of secondary plant functions and equipment.

The NSSS software has no direct protective or safety significance and functions only as an operating aid by enhancing established manual operating procedures.

7.7.1.2.5 Emergency Response Data System (ERDS)

This function was added to the process computer in response to plant commitments to NUREG-1394. The equipment supporting the ERDS consists of a telephone modem connected to an NRC supplied telephone line and the software to perform the function. The purpose of the link is to transmit the values of several parameters to the NRC headquarters for their review and analysis during and shortly after declared emergencies at the "Alert" or higher level. The data consists of a selected set of meteorological, radiation, and NSSS process parameters averaged from the ERCS database. Upon initiation of the link, the data is sent to the NRC's computers at a predetermined frequency. The link does not allow for two way control. Control of the link is as directed by plant procedures.

7.7.1.3 Performance Analysis

During normal plant operations the ERCS is used by the Control Room personnel for information needs related to routine plant operation. The terminals in the TSC, EOF and HQEC can be utilized as plant information sources for various activities.

The NSSS has no direct protective or safety significance and functions only as an operating aid. The NSSS outputs are categorized as follows:

a. Information that is primary output for plant operation for which alternate administrative actions are required by the Technical Specifications.

b. Information that is not primarily used for plant operation including outputs for which no administrative actions are required.

There are four outputs in the first category, the Rod Bank Deviation, Delta-I, Flux Tilt and Rod Insertion Limit. Each of these routines operates an audible alarm as well as a visual printout whenever the preset limit has been violated. If any of these programs are inoperable, the Technical Specifications require the readings to be manually logged. Hence, if the plant computer is not in service the aforementioned administrative action is required.

During an emergency condition covered by the Emergency procedures the TSC, EOF and HQEC terminals are manned by personnel for the purposes covered by the appropriate procedures. The information available on the terminals will be used to carry out the functions of the emergency centers.

Information related to the SPDS capabilities was provided to the NRC in Reference 25 and 26. NRC acceptance of this design is documented in Reference 27.

7.7.1.4 Inspection and Testing

The ERCS including the NSSS software are on-line systems that are capable of self-testing. Remote multiplexing hardware provides a real time test of calibration points that are used by data acquisition software to compensate for any drift in A/D hardware. Constant checking by the data acquisition function of PMS flags field inputs that are outside acceptable engineering limits. Diagnostic checks are manually initiated to assure proper operation of the computer hardware.

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7.8 OPERATING CONTROL STATIONS

7.8.1 Control Room

GDC-11 The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit continuous occupancy of the control room under any credible post-accident condition or as an alternative, access to other areas of the facility as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel.

The plant is equipped with a single control room which contains those controls and instrumentation necessary for safe operation of both units, including the reactors and the turbine generators, under normal and accident conditions.

Control Room habitability during and after accident conditions has been considered in the design of the control room (see 7.8.2). 01-058

Remote shutdown capabilities are provided throughout the plant to be used when the control room is uninhabitable (see 7.8.5). 01-058

01-058 01-061

7.8.1.1 Control Room Layout

The layout of the vertical bench front panels, electrical console, and nuclear, incore and radiation monitoring racks for the control room is shown in Figure 7.8-1.

The control board (including the bench front vertical panels and console) design incorporates an arrangement of controls and information instrumentation for the safe operation of both the nuclear steam supply system and the conventional plant equipment in such a manner as to effectively reduce the amount of board area that the operator needs to keep under his surveillance, and to provide quick access to controls. Control switches on the board are grouped according to operating function to minimize the juxtaposition of unrelated control functions.

Referring to Figure 7.8-1, vertical bench front panel A contains instrumentation and controls for the non-safeguards shared system of the plant (i.e., station air; fire protection; etc.). Panels extending to the left of the center section of A provide for control of unit 1; while the panel sections to the right of A are for unit 2. Instrumentation and controls for cooling water, component cooling, containment fan coils, and containment spray for unit 1 are segregated on the left hand side of A.

Vertical bench front panel "B-1" (just to the left of "A") incorporates instrumentation and controls for the waste disposal system; the passive safety injection system; the safety injection system; the residual heat removal system; and the CVCS let-down system, all for unit 1.

Instrumentation and controls for the CVCS system recorders for the nuclear instrument system and rod controls; and the instrumentation and controls for the reactor coolant system are located on vertical bench front panel section "C-1".

Vertical bench front panel section "D-1" includes the instrumentation and controls for the steam generator system.

Vertical bench front panel "E-1" incorporates the auxiliary feedwater system instrumentation and controls; and controls for the feedwater; condensate; vacuum; turbine and generator.

Reheater drains; moisture separator drains; heater drains and heater drain tank pumps; and the circulating water system instrumentation and controls are located on vertical bench front panel "F-1".

The NIS "console" at the left hand end of vertical bench front panel "F-1" incorporates the four nuclear instrumentation system racks containing amplifiers, signal conditioners, trip units, power supplies, etc. Indicators, recorders, status lights and related switches are distributed between this panel and the NIS system portion of panel "C-1".

Unit 2 instrumentation and controls are arranged in a modified mirror image to the right of the center of panel "A".

Electrical console "G" which is located directly in front of the A vertical bench front panel contains instrumentation and controls to monitor and control the 4 KV and monitor the 480 volt plant safeguards distribution system. This console also contains the instrument and controls for the four emergency diesel generators.

Control stations are packaged in modular form, with switches and associated indicating lights in individual sub-housings, which are grouped according to function to minimize the possibility of operator error. ESF pump motor power feed breakers indicate that they have closed by energizing indicating lights on the control board.

Control stations with both automatic and manual positions are provided with smooth transfer of function.

In general, indication instrumentation controllers are incorporated in the vertical section of the bench front panel, with annunciators located above, and switch groups on the bench front section.

7.8.1.2 Detailed Control Room Design Review 01-058

In response to NUREG-0737 and Generic Letter 82-33 (Supplement 1 of NUREG-0737), the plant conducted a comprehensive review of the control room layout. The objective of this review was to improve the ability of the nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them. To achieve this objective, the design review was to identify any modifications of the control room configuration that would contribute to a significant reduction of risk and enhancement in the safety of operation. 01-058

A survey was performed of the control room to review the control room layout, the usefulness of audible and visual alarm systems, the information recording and recall capability, and the control room environment. This survey compared the control room configuration with acceptable human factors principles. Areas of weakness were considered as Human Engineering Discrepancies (HEDs). (References 22 and 23) 01-058

The HEDs were prioritized and were considered for correction. At the completion of the review a Detailed Control Room Design Review (DCRDR) summary report was required to be submitted to the NRC for review and approval (Reference 21). The report included an identification of the HEDs, which HEDs were being corrected, justification for not correcting or fully correcting selected HEDs and the schedule for completing any design improvements. Design improvements in the control room layout and control board layout resulting from the review were implemented (Reference 54). The conclusion reached by the NRC was that the DCRDR activities had adequately addressed and met the requirements of Supplement 1 of NUREG-0737 (Reference 24). 01-058

7.8.2 Control Room Habitability

Sufficient shielding, distance, ventilation, and containment integrity are provided to assure that control room personnel are not subjected to doses under postulated accident conditions during occupancy of, and ingress to and egress from the control room which would exceed the radiological consequences discussed in section 14.9. A control room special ventilation system is provided to protect the control room personnel during accident condition. The special ventilation system's features and performance are described in section 10.3.3.

Area Radiation Monitor Channel R1 monitors control room radiation level and is described in section 7.5.3.1. 01-058

See Section 2.9.4 for further control room habitability analysis.

7.8.3 Additional Control Stations

Local control panels are provided for certain systems and components which are used on an intermittent basis. Such systems are the Waste Disposal System, Sampling System, Boron Recycle System, heating boilers and the Turbine-Generator Hydrogen Cooling System. In these cases, however, appropriate alarms are located in the control room and are activated to alert the operator of equipment malfunction or approach to unsafe conditions.

The waste disposal and boron recycle control panels are located in the auxiliary building. These boards permit the operator to control and monitor the processing of wastes in the general area where equipment is located. Alarm signals from these system components annunciate on this board. Actuation of any alarm on this panel actuates a general alarm on the main control board. In this manner general surveillance over these systems is maintained in the control room.

7.8.4 Fire Prevention Design

The probability of a fire within the control room is extremely small. To restrict the possibility of fire originating in the control room, negligible combustible material, trim or furnishings are used in its construction. However, should a large fire occur which will result in evacuation of the control room, the method for shutting down the plant is described in Section 10.3.1.5.1. This section discusses the effects of a small fire that may not result in significant damage to control room equipment and circuits.

Electrical circuits are limited to those associated with lighting, instruments and control. Lighting circuits are 120 volts; instrumentation power and control circuits are either 120 volts a-c, 125 volts d-c or lower. All 120 and 125 volt circuits are protected against short circuits by either fuses or circuit breakers. The power levels on the instrumentation signal circuits are so low that it is incredible that short circuits in these could present a fire hazard. Switchboard wiring is flame resistant.

Because of the short circuit protection provided for the circuits in the control room, the fire hazard presented by the electrical equipment due to electrical faults, is minimal.

The discussion that follows summarizes the original control room fire protection design intent. Additional information relative to the PINGP Fire Protection Program is included in the USAR Section 10.3.1.5.1.

To prevent the spread of fire from the electrical rooms beneath the control room, the following provisions are made:

a. Cables used throughout the relay room have an exterior jacket that meets the Insulated Power Cable Engineer's Association (IPCEA) test requirements. All non-metallic materials in the cable construction and accessory devices have been chosen so that they will not support combustion. Power cables for the 480 volt system are three conductor, insulated with ethylene propylene rubber, with a neoprene-like, or an asbestos braid impregnated with flame retardant compound jacket and interlocked aluminum armor overall.

b. Cabling and wiring in the relay room are installed in trays or in metallic conduit.

c. Protective devices are furnished that limit the short circuit current values that minimize the temperature rise to which insulation is exposed.

d. Structural and finish materials for the control room, relay and battery rooms were selected on the basis of fire resistant characteristics. Structural floors and interior walls are of reinforced concrete. Interior partitions are metal, masonry or gypsum dry walls on metal joists. The control room suspended ceiling consists of aluminum louver grids with fluorescent light fixtures mounted above the grids. Door frames and doors are metallic. Wood trim is not used. 01-058

Because of the nature of the equipment involved and its design, an equipment fire in the control room would not cause abandonment of the control room and would not prevent the operator from shutting down the reactors to the condition which would no longer require the engineered safeguards systems to be functional.

As stated previously, it is considered that because of the overload and short circuit protection provided for the electrical equipment within the control room the fire hazard due to electrical faults is minimized. Further, if a fire does occur within the electrical equipment, its magnitude will be restricted to minor proportions by the non-combustible and flame resistant nature of the electrical materials involved and because all electrical wiring devices are surrounded by or mounted in metal or fire retardant enclosures. Thus, although some isolated damage to the electrical equipment could result, the multiplicity of the reactor and engineered safeguards system trip circuits, and the associated segregation of redundant channels including wiring, will keep the protection systems of the reactor unimpaired and the operator will be able to execute a reactor shutdown primarily from the main control room.

A fire which could conceivably lead to the temporary abandonment of the control room can only arise from a source which is external to the electrical equipment. The fire resistant nature of the structural and finish materials for the control room and control room furnishings, makes the probability of this type of fire minimal. In the event of such a fire, however, and even if it were to be uncontrolled, it is unlikely that it could be of sufficient magnitude to affect the electrical equipment, all of which is contained within (and thereby shielded from the fire) metal cabinets. The operator has available portable respiratory equipment. Portable fire extinguishers are located in the control room for the operator's use. In addition to the control room fire extinguishers, fire extinguishers are also provided in the cable spreading and battery rooms. The extinguishers are designed in accordance with National Fire Code and National Fire Protection Association specification. The equipment provided is adequate to control any such fire and prevent a forced abandonment of the control room.

7.8.5 <u>Emergency Shutdown Control</u>

The following discussion applies to the original design intent for shutdown from outside the control room. Section 7.8.4 provides the discussion relative to the inhabitability of the control room during a fire scenario. The ability to shutdown for a control room fire is discussed in Section 7.8.4. The discussion that follows should not be construed as satisfying 10CFR50 Appendix R. Safe shutdown analysis which forms the basis for satisfying 10CFR50 Appendix R is also included in USAR Section 10.3.1.

Provisions have been made so that the plant can be shutdown and maintained in a safe condition by means of controls located outside the control room. During such a period, the reactor is tripped and the plant maintained in the hot shutdown condition. If the shutdown is extensive, the Reactor Coolant System is borated.

Local controls are located such that the stations to be manned, and the times when attention is needed, are within the capability of the plant operating crew. The plant intercom system provides communication so that the operation can be coordinated.

The functions for which local control provisions have been made are listed below along with the type of control and its location in the plant. Transfer to these local controls is annunciated in the control room.

After the initial transient, basically all control is manual if outside the control room. It is expected that all automatic systems will continue functioning until local manual control is established. However, the reactor can be tripped manually by equipment outside the control room if necessary, either by opening the reactor trip and/or power supply breakers or by actuating the manual turbine trip on the turbine. The necessary indicators and manual controls for the hot shutdown capability are provided outside the control room. The controls include the necessary speed and valve controls and local and remote stop/start push button motor controls with local selector switch for local operations. These include controls for the main feed and auxiliary feedwater systems and atmospheric relief and steam dump valves for maintaining the steam generator water level.

7.8.5.1 Equipment Control Outside Control Room

If the control room should be evacuated suddenly without any action by the operators, the reactor can be tripped by either of the following:

a. Open reactor trip and/or rod power supply.

b. Actuate the manual turbine trip on the turbine (above P9).

Following evacuation of the control room the following systems and equipment are provided to maintain the plant in a safe shutdown condition from outside the control room:

a. Decay Heat Removal 01-058

Following a normal plant shutdown, automatic steam dump control maintains the reactor coolant temperature at its no load value. Redundancy and full protection, where necessary, is built into the system to ensure the continued operation of the steam generator units. If the automatic steam dump control system is not independently available, controlled relief valves on each steam generator maintain the steam pressure. These relief valves are further backed up by safety valves on each steam generator. Numerous calculations, verified by startup tests on the Connecticut-Yankee and San Onofre Power Plants have shown that with the steam generator safety valves alone, the reactor coolant system maintains itself close to the nominal no load condition. For decay heat removal it is only necessary to maintain the control on one steam generator.

The normal source of water supply when making continued use of the steam generators for decay heat removal is the auxiliary feed circuit, where supplies of water are available from the condensate storage tanks and cooling water. Feedwater may be supplied to the steam generators by the auxiliary electrical feed pump or by the auxiliary steam driven feed pump; these pumps and associated valves have local controls.

b. Reactivity Control

Following a plant shutdown to hot shutdown condition, boric acid poison is added to the reactor coolant system to maintain subcriticality. For boron addition the chemical and volume control system or the safety injection system can be used. Boration requires the use of:

1. Charging pumps and volume control tank with associated piping.

2. Boric acid transfer pumps with tanks and associated piping.

   It is worthy of note that, with the reactor held at hot shutdown conditions, boration of the plant is not required immediately after shutdown. Xenon decay below the equilibrium operating level does not begin immediately, but could occur up to 26 hours after shutdown, depending upon power history, and a further period lapses before the 1% reactivity shutdown margin provided by the full length control rods has been canceled. This delay provides ample time for emergency measures. The letdown line and component cooling water systems are not required for boration capability.

c. Pressurizer Pressure and Level Control

Following a reactor trip the reactor coolant temperature automatically reduces to the no load temperature condition as dictated by the steam generator temperature conditions. This reduction in the reactor coolant water temperature reduces the reactor coolant volume and if continued pressure control is maintained reactor coolant makeup is required.

The pressurizer level is controlled in normal circumstances by the chemical and volume control system. The facility for boration is provided as described above; it is only necessary to supply water for makeup. Water may readily be obtained from the normal sources; i.e., the makeup water tank or refueling water storage tank. The Safety Injection Pumps can also be used to perform this function.

7.8.5.2 Indication and Controls Provided Outside the Control Room

The specific indication and controls provided outside the control room for the above capability are summarized as follows:

a. Level indication for the individual steam generators visible from the auxiliary feed pumps.

b. Pressure indication for the individual steam generators visible from the auxiliary feed pumps.

c. Pressurizer level and RCS pressure indicators visible from the auxiliary feed pumps. Pressurizer level indicators visible at the charging pumps local control point.

d. Reactor coolant system wide range pressure and wide range temperature (T-Hot and T-Cold), visible from the auxiliary feed pumps.

7.8.5.2.1 Controls

Local stop/start push button motor controls with a selector switch are provided for control of the following motors. The selector switch transfers control of the switchgear from the control room to local either at the motor or the hot shutdown panel (HSDP). Placing the local selector switch in the local operating position gives an alarm in the control room and turns out the motor control indicating lights on the control room panel.

a. Auxiliary Motor Driven Feedwater Pumps (Local).

b. Charging Pumps (HSDP for 11, 13, 21, 23 and Local for 12 and 22).

c. Boric Acid Transfer Pumps (HSDP).

d. Containment Air Fan Coil Units (Local).

e. Control Room Air Handling Unit Including Control for the Air Inlet Dampers (Local).

f. Component Cooling Water Pumps (Local).

g. Instrument Air Compressors (Local).

h. Safety Injection Pumps (Local).

7.8.5.2.2 Speed Control

Speed control is provided locally for the Charging Pumps.

7.8.5.2.3 Valve Control

a. Auxiliary Feed Control Valves. (These valves are located local to the auxiliary feed pumps.)

b. Atmospheric Relief Valves (HSDP).

c. All other valves requiring operation during hot standby can be locally operated at the valve.

d. Letdown orifices isolation valves (HSDP).

7.8.5.2.4 Pressurizer Heater Control

Stop and start buttons with selector switch and indicating lamps are at the HSDP for two backup heater groups.

7.8.5.3 Lighting

Emergency lighting is provided in all operating areas as required to support emergency shutdown outside of the control room. Detailed design of the plant lighting system is discussed in Section 10.3.6.

7.8.5.4 Communications

The communication network provides communications between the area of the auxiliary feed pumps and the charging pumps, boric acid transfer pumps, emergency diesel generators, and the outside exchange without requiring the control room. The plant communication systems design detail is discussed in Section 10.3.8.

7.8.5.5 Cold Shutdown Capability From Outside the Control Room

As described above, provisions are included in the design for placing and maintaining the plant in the hot shutdown condition from outside the Control Room. There is no conceivable need or requirement to place the plant in a cold shutdown condition under these circumstances; however, a walk through of the steps which could be taken by the operator to place the plant in a cold shutdown condition from outside the Control Room is as follows:

Procedure

a. Borate to a minimum of cold shutdown concentration

   1. Override pressurizer level to allow injection of boric acid using charging pumps.

2. Verify injected boric acid volume by checking volume decrease in boric acid tank.

3. Sample loop several times to check boron concentration and mixing.

b. Pressure Control

1. Keeping the loops subcooled to aid natural circulation, use charging pumps to pressurize the Reactor Coolant System.

2. The upper pressure limit is initially set by the power relief valves or safety valves.

c. Temperature Control

1. Steam generator pressure is used as an indication of RC temperature above 250°F with hand control of atmospheric relief on each steam generator to allow cooldown.

2. Cooldown rate is established by Technical Specification Limits. Forced cooldown by steam dump must be proceeded by appropriate pressure decay by heat loss from pressurizer.

d. Volume Control

1. Pressurizer level and reactor coolant/pressurizer pressure are used to monitor shrink and pressure with the charging pump making up contraction with refueling water.

e. Steam generator level is controlled by manually operating the auxiliary electrical feed pump and valves.

f. Electric Power

1. 480 V busses energized by offsite power or by onsite diesels.

2. Component cooling water starts automatically on return of power. Cooling water starts automatically.

g. Safeguards Deactivation

1. Lock out safety injection pump and residual heat removal pumps at switchgear.

2. Manually close the accumulator isolation valves. This procedure will bring the RCS to around 350°F with pressure about 100 psi above saturation.

h. Manually align RHRS for cooldown

1. Unlock RHR pump and align.

2. Initiate component cooling to one RHX and isolate the other.

3. Close outlet valves on active heat exchanger and outlet to RCS. Open the RCS letdown valves and read RC pressure by pump gauges.

4. Start RHR pump from its breaker and allow to circulate on mini-flow lines until temperature and boron concentration are checked.

5. Open RHR outlet valves to RCS.

6. Open RHX bypass line to establish flow in system.

7. After checking pressure and temperature open RHX outlet valve and close RHX bypass valve.

8. Temperature must remain consistent with pressure thus the ultimate cooldown rate is determined by pressurizer heat loss and consequent depressurization. Pressurizer level will be maintained by charging pumps taking suction from the RWST.

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7.9 SEISMIC DESIGN, TESTING AND MONITORING

7.9.1 Seismic Design

7.9.1.1 Original Equipment Requirements

The seismic design criteria for PS&E supplied equipment (including equipment for the Emergency Power Systems) required that the equipment, including all components furnished, be designed to withstand, without damage or interruption of operations, the forces resulting from a Design Basis Earthquake.

Based on a seismic analysis giving response acceleration spectra for selected floors of plant buildings, the Class I electrical equipment manufacturers were required to present documentation, either in the form of mathematical analysis or testing data (on a prototype or the actual equipment), to ensure compliance with physical integrity requirements and seismic criteria.

Certified reports of tests included, as a minimum, accelerations to which the equipment was subjected, associated frequency and number of test cycles, qualitative performance of the equipment during and after the test, and approximate fundamental frequency of the equipment.

When manufacturers elected to perform seismic analysis by mathematical calculations, these calculations were reviewed and approved by PS&E.

For either earthquake (operational or design basis) the equipment is designed to assure that it does not lose its capability to perform its function; i.e., shut the plant down and maintain it in a safe shutdown condition.

For the design basis earthquake, there may be permanent deformation of the equipment provided that the capability to perform its function is maintained.

7.9.1.2 Current Seismic Qualification Requirements 01-065

The current seismic qualification requirements are consistent with the original licensing commitments to seismic design. That is, the plant must, as a minimum, meet the original plant seismic requirements for design of equipment. Seismic criteria are selected on a project specific basis.

An acceptable alternative method from that described in 7.9.1.1 for verifying seismic adequacy is described in Section 12.2.14. This alternative method applies to new, modified or replacement Design Class I mechanical and Class 1E electrical equipment. Restrictions on the use of the alternative method are also discussed in Section 12.2.14. 01-065

7.9.2 Seismic Testing

7.9.2.1 Original Equipment Seismic Testing Criteria

Type testing was done on equipment by the vendor or Westinghouse using conservatively large accelerations and applicable frequencies. The peak accelerations and frequencies used were checked against those derived by structural analyses of operational and design bases earthquake loadings.

The unidirectional testing was performed in a conservative manner, thus providing a margin against any greater effects which may possibly result from the worst combination of simultaneous testing. This conservatism consisted of: 1) an input sine beat motion with 10 cycles per beat, 2) resonant testing of all determined and applicable natural frequencies, 3) further testing at other selected frequencies, and 4) high input acceleration values particularly for the vertical direction.

Typical protection system equipment was subjected to type tests under simulated seismic accelerations to demonstrate its ability to perform its functions.

7.9.2.2 Original Equipment Seismic Testing Methodology

The detailed test procedures used for the seismic tests including requirements for the equipment mounting, vertical and horizontal accelerations and the frequency ranges, are provided in WCAP 7817 (Reference 16) "Seismic Testing of Electrical and Control Equipment." Information on the actual accelerations at the floor was furnished in the Blume Report Numbers 2 and 4 (JAB-PS-02 and 04).

Equipment in the Reactor Protection System and the Engineered Safety Features Actuation System was type tested by Westinghouse to the above referenced qualification testing requirements. The qualification testing requirements used to assure that the criteria were satisfied on the two systems is contained in the topical report WCAP-7817, (Reference 16) Section 3, entitled "Test Procedures." Equipment for the nuclear plant is procured on a similar (identical) basis to that which is qualified.

The following considers the performance of the required safety actions during the tests.

Test input signals were sent to the process control and nuclear instrumentation equipment so that these systems were operating in a normal plant at power configuration during the seismic test. Both analog and bistable output signals were continuously recorded during the test. The bistable circuitry, whose output signals initiate reactor trip and safeguards actuations, receives its input signals from the analog circuitry. Its trip set point was adjusted so that it was approximately 5% above the value of the analog input signal. The output signal is approximately 118 volts A.C. in the pretrip condition and reduces to 0 volts after being tripped. In these two systems, the bistable circuitry does not cause any mechanical motion when tripped, but merely reduces its output voltage to zero volts.

Upon completion of the tests, the analog output signal recordings were reviewed for any change in value that would negate or delay the tripping of the bistable circuitry. Also the test input signals were individually changed before and after each test to check the proper operation of the analog and the bistable trip circuitry.

This type of test procedure assures that the reactor trip and safeguards actuation circuitry remains functional and that no trips are negated by the seismic vibrations. The pressure and differential pressure transmitters were also tested in their normal plant operating mode, i.e., each transmitter was connected to a pressure source and the pressure set and regulated according to the pressure measuring range of each type of transmitter. A laboratory type pressure transmitter (not vibrated) was used to monitor the electrical analog output signals of the transmitter under test.

These analog output signals are sent to the process control equipment where various reactor trip and safeguard actuation signals are generated if the pressure transmitter signals exceed some pre-set value. Thus these output signals were expected to remain relatively constant during the vibration period and to indicate their pre-test values upon completion of the test.

As in the process control and nuclear instrumentation tests, upon completion of the seismic tests, the transmitter analog signal recordings were reviewed for any change in value that would negate or delay the tripping of the bistable circuitry in the process control equipment, and their final values were compared with the pre-test values to check for any output signal change. Again this type of test assures that the transmitter mechanisms and electrical circuitry remain functional and would not negate a valid reactor trip or safeguards actuation during a seismic disturbance.

7.9.2.2.1 Instrumentation Subject to Seismic Testing

The following is a list of the types of original plant equipment utilized in the reactor protection, nuclear instrumentation, engineered safety features actuation, radiation monitoring, and part of the emergency power systems which have been tested.

a. Static Inverter: Converts a nominal 125 VDC to approximately 120 VAC.

b. Process Equipment: 3 cabinets used for monitoring reactor coolant flow, temperature and pressure, pressurizer level and pressure, safety injection flow, and steam generator pressure and feedwater level. The cabinets include at least one of each type of module used in all of the various process protection and safeguards actuation channels.

c. Safeguards Actuation Racks: 2 cabinets containing relay logic monitors.

d. Nuclear Instrumentation and Radiation Monitoring Systems: 2 cabinets containing NIS and RMS equipment. 01-036

e. Pressure and Differential Pressure Transmitters: Used for coolant pressure and flow, pressurizer pressure and water level, and steam generator pressure and level, and steam flow.

A resonant search was run from 1 to 60 Hertz in discrete increments for 1 to 5 Hz, 5 to 10 Hz, 10 to 25 Hz and 25 to 60 Hz. Finer increments were taken around resonant points. A resonant search was made twice in each of three directions. 01-036

a. Vertical

b. Horizontal - side to side 01-036

c. Horizontal - front to back

Within the PS&E scope the following instrument and control items were type tested:

a. One prototype pressure transmitter of each pressure range for all QA Type I pressure transmitters.

b. One pressure switch for each type of QA Type I pressure switch (vacuum breaker pressure switch, and auxiliary building differential pressure switch for Shield Building Ventilation system recirculation mode automatic control).

7.9.2.2.2 Electrical Equipment Subject to Seismic Testing

Equipment such as 4160V switchgear, 480V switchgear, battery chargers, batteries and racks, and motor load centers were shake tested on a prototype basis.

As an example of one of these tests, two cubicles of power switchgear containing circuit breakers, potential transformers and a complement of control and protection relays were tested on an electro-hydraulic shaker system suitable for low-frequency long-stroke testing.

01-036

Specific circuits were connected to a recorder and monitored during the test, including the following:

a. Breaker Primary Contacts

b. Potential Transformer Primary and Secondary Connections

c. Auxiliary Relay, Timing Relay, Overcurrent and Voltage Relay Contacts

d. Multi-contact Relay Contacts

e. Breaker Auxiliary and Cell Switches

For seismic testing of relay contacts relays were tested in two states: (1) relay deenergized; and (2) relay energized with normal voltage or current. Overcurrent relays were set on the lowest tap and time lever setting and sufficient current passed through the coils to just operate the relay contacts.

Relay contacts were purposely operated electrically at random times during testing to evaluate their performance.

A circuit breaker was electrically closed and tripped at random times during the test to check its performance.

The results of the test showed that the switchgear and its components continued to operate without malfunction during and after a simulated earthquake up to an input of 0.5g, and in most cases, well above this point.

Within the PS&E scope the following electrical items were type tested:

a. One prototype of each type of electrical penetration.

b. Unit 1 emergency diesel generators.

c. Unit 1 4160 and 480 volt switchgear. 480 volt switchgear was subsequently replaced, see 7.9.2.3 for new seismic testing requirements.

d. Motor control centers.

e. Batteries and battery racks. The original batteries and battery racks have been replaced, see 7.9.2.3 for new seismic testing requirements.

f. All relay and control cabinets associated with the above.

7.9.2.3 Current Seismic Testing Requirements

The current seismic testing requirements are consistent with the original licensing commitments for seismic testing. That is, the plant must, as a minimum, meet the original plant seismic requirements for testing of equipment. Seismic criteria are selected on a project specific basis. 01-065

Equipment which has been procured for either new or replacement Class 1E applications has been tested seismically in accordance with the requirements of either the original plant licensing commitments, or a more recent qualification standard.

Examples of this include the following Class 1E equipment procured for various projects:

a. Unit 1 & 2 4160 volt switchgear IEEE-344-1987 01-065

b. Unit 1 & 2 480 volt switchgear IEEE-344-1987

c. Unit 2 480 volt motor control centers (2TA1 & 2TA2) IEEE-344-1975

d. Unit 2 emergency diesel generators (D5 & D6) IEEE-344-1975 01-065

e. Unit 1 & 2 station batteries and battery rack IEEE-344-1975

f. Unit 1 & 2 station battery chargers IEEE-344-1975

g. Control Board G-1 in Main Control Room IEEE-344-1987 01-065

7.9.3 Seismic Monitoring System

The Seismic Monitoring System was installed in response to AEC questions during original plant licensing. These commitments also stated that the central seismic monitoring and recording system would be installed in accordance with Safety Guide 12 (Reference 58). The purpose of this QA type 3 system is to monitor and record seismic events and to determine the peak seismic accelerations of critical plant piping systems during a seismic event.

The seismic monitoring system is composed of the following components:

a. Accelerometer Triggers - designed to actuate alarms based on the seismic activity peak thresholds.

b. Triaxial Accelerometers - designed to produce an output signal for recording of seismic activity.

c. Seismic Recording Panel - designed to receive and process data from the triaxial accelerometers.

d. Triaxial Peak Recording Accelerographs - designed to locally record the peak seismic forces placed upon the monitored equipment.

7.9.3.1 Accelerometer Triggers

The Accelerometer Triggers are located in the Auxiliary Building, elevation 695′ (see Figure 7.9-1). These instruments are designed to sense the initial acceleration associated with the free-field seismic event. One horizontal trigger, one vertical trigger and two omni-triggers (contains both a horizontal and vertical trigger) are used to sense the response of the Auxiliary Building.

The upper setpoints for the triggers are based upon the seismic classifications as found in the Blume Report for Operational Basis Earthquake (OBE), and Design Basis Earthquake (DBE). In addition, a Low Seismic Activity (LOW) setting is used to indicate the presence of weak seismic activity.

The triggers are designed for two purposes. First, to initiate operator alarms which identify the relative magnitude severity of the seismic occurrence. Second, the triggers initiate the sensing and recording system measured by the triaxial accelerometers.

The triggers initiate a series of control room annunciators. Beginning with the lowest severity, the SEISMIC EVENT annunciator will light. If the seismic event is severe enough, then the OPERATIONAL BASIS EARTHQUAKE and/or the DESIGN BASIS EARTHQUAKE annunciator will light.

Normally, the sensing and recording system is in an inactive state; the system will begin recording data when the intensity of the seismic event a pre-set level as detected by the Accelerometer Triggers. The recording system will return to the inactive state after the intensity of the seismic event has returned below the pre-set level.

7.9.3.2 Triaxial Accelerometer

Four Triaxial Accelerometers are located in the plant, three in containment and one in the Auxiliary Building, elevation 695′ (see Figure 7.9-1). These instruments are designed to sense seismic acceleration in three dimensions. Each triaxial accelerometer consists of three single channel accelerometers which are mounted on mutually perpendicular axes. The output of each accelerometer provides an independent signal to the recording module.

The seismic recording system, once initiated, will record all 12 channels of the four triaxial accelerometers. The preselected accelerometer may be displayed visually for the three axes of its vibration.

7.9.3.3 Seismic Recording Panel

The recording panel contains various indicating devices.

1. An indicator which shows that the seismic event is in progress.
2. An event indicator which shows that a seismic event is presently occurring or has occurred in the past.
3. Recording equipment to record the output of each accelerometer channel along with the time-base information.

The recording panel also contains the necessary calibration controls to allow periodic calibration of the system.

The recording system is capable of performing a playback of each individual channel and simultaneously show the time-base information.

The recordings discussed above will display calibrated indices. This will permit a prompt determination by the operator as to the accelerations experienced at the base of the containment structure or other detector locations. These evaluations can be made promptly and without subjective interpretation within a few minutes of the seismic event to which attention is called by the annunciator.

The requirement for a prompt evaluation of the recordings is signaled by actuation of the OBE annunciator. If examination of the recordings indicate a seismic event greater than or equal to the level of the OBE an orderly shutdown will be initiated and detailed plant inspection performed.

7.9.3.4 Triaxial Peak Recording Accelerographs

Eleven Triaxial Peak Recording Accelerographs are located throughout the plant and screenhouse (see Figure 7.9-1). These instruments are designed to sense seismic peak acceleration in three dimensions. Each triaxial peak recording accelerograph consists of three single torsional accelerometers which are mounted on mutually perpendicular axes.

The output of each torsional accelerometer moves a magnetic stylus across a pre-lined magnetic film. This produces an erasure effect which, once the film is developed, can be viewed through a microscope or viewer equipped with a calibrated reticule.

These are considered passive devices, in that they perform only a monitoring function of the peak acceleration of the particular area of the plant. It is intended that the magnetic films would be read after an earthquake to determine the peak seismic forces present at the given location.

Five other Triaxial Peak Recording Accelerographs are located on plant piping. The purpose of these instruments is to record the seismic forces which plant piping was subjected to, then use this data for analysis and possibly restart justification after a seismic event. These instruments are identified on Figure 7.9-1.

7.9.3.5 Design Basis

Safety Guide 12 forms the design basis of the Seismic Monitoring system. The requirements for the system and how the plant meets or exceeds these requirements are identified as follows:

a. Each plant site shall have one strong motion triaxial accelerograph in the basement of the reactor containment structure and one at a higher elevation.

   Unit 1 containment structure has a triaxial accelerometer located at the 697.5′ level, each unit has a triaxial accelerometer at a higher elevation in containment.

b. Each accelerometer should be: separated by a vertical distance that is a significant fraction of the containment building height, oriented such that the three axes are in alignment with each other, located directly over one another, accessible for maintenance and recovery of data, and mounted to the containment structure or on a structure mounted directly to the containment structure.

   Each containment triaxial accelerometer is separated by approximately 68 feet of vertical distance. Each is oriented with the axes in alignment and located as close as is practical to be directly over one another. Each triaxial accelerometer is tested and maintained. The lower level accelerometers are located on the containment foundation and, the upper level accelerometers are located on structures which are mounted directly on the containment structure as shown in Figure 7.9-1.

c. Other instrumentation, such as peak recording accelerographs and peak deflection recorders should be installed on other Category I structures, system and components.

   Other seismic instrumentation is installed in the Auxiliary Building, Screenhouse and the Turbine Building as shown in Figure 7.9-1.

d. The value of the peak acceleration level experienced in the containment structure should be indicated in the control room or available to the control room operator within a few minutes after the earthquake.

   As described in 7.9.3.2, the triaxial accelerometers output is recorded once the intensity of the seismic event reaches a pre-set level as detected by the Accelerometer Triggers. Alarms alert the operator to the presence of seismic activity and within a few minutes, the operator can obtain data on peak acceleration levels by reading traces prepared by the seismic recording system.

e. Instrumentation should be designed to perform its function satisfactorily over the appropriate range of environmental conditions.

   Triaxial Accelerometers are designed to remain operational when exposed to -40°F to 140°F, a 20g vibration, and a 50g shock force. The instruments are hermetically sealed.

f. A plan should be developed for timely utilization of the data to be obtained from installed seismic instrumentation.

   The seismic recording system is designed to record seismic acceleration as measured by the accelerometers. This data is available to the operator when the seismic recording panel is observed.

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7.10 POST ACCIDENT MONITORING INSTRUMENTATION

7.10.1 Design Basis

The design bases for Post Accident Monitoring Instrumentation includes commitments to the following:

GDC-13 (October 23, 1978) **Instrumentation and Control** - Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate control shall be provided to maintain these variables and systems within prescribed operating ranges.

GDC-19 (October 23, 1978) **Control Room** - A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident.

Equipment at appropriate locations outside the control room shall be provided:
(1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and control to maintain the unit in a safe condition during hot shutdown; and
(2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

GDC-64 (October 23, 1978) **Monitoring Radioactivity Releases** - Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss-of-coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

NUREG 0737 "Post TMI Requirements" included a requirement to install specific instrumentation channels to monitor post accident conditions.

NUREG 0737 SUPPLEMENT 1 (NRC Generic Letter 82-33) included a requirement to comply with Regulatory Guide 1.97 (Rev 2, 1980).

REGULATORY GUIDE 1.97 "Instrumentation to Assess Plant and Environs Conditions During and Following an Accident" integrates the previous requirements into a single document. It specifies specific parameters to be monitored and includes the required range, design category, seismic and environmental qualification, quality assurance, power supply and display requirement. Exceptions were allowed to the requirement of Reg. Guide 1.97, providing adequate technical justification was provided.

The revised commitments apply to Post Accident Monitoring Instrumentation only, and do not apply to other instrumentation or the control room in general.

7.10.2 Equipment Classification Methodology

The event monitoring instrumentation was installed as required by the NRC TMI action plan to ensure that sufficient information is available on selected plant parameters, to monitor and assess these variables during and following an accident. The event monitoring instrumentation does not perform a protective action. This capability is consistent with the recommendation of NUREG-0578 and NUREG-0737.

Regulatory Guide 1.97 divides the various parameters into five types:

Type A Variables - those variables to be monitored that provide the primary information required to permit the control room operator to take specific, manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for design basis accidents. This does not include those variables that are associated with contingency actions that may also be identified in written procedures.

Type B Variables - those variables that provide information to indicate whether plant safety functions are being accomplished. Plant safety functions are:

Reactivity control
Core cooling
Maintaining reactor coolant system integrity
Maintaining containment integrity

Type C Variables - those variables that provide information to indicate the potential for being breached or the actual breach of the barriers to fission product releases. Those barriers are:

Fuel cladding
Primary coolant pressure boundary
Containment

Type D Variables - those variables that provide information to indicate the operation of individual safety systems and other systems important to safety.

Type E Variables - those variables to be monitored as required for use in determining the magnitude of the release of radioactive materials and continually assessing such releases

Design and qualification categories are specified for each variable. Three categories are identified. A summary of the design and qualification requirements follows:

Category 1

The instrumentation should be qualified in accordance with Reg Guide 1.89 "Qualification of Class IE Equipment". The qualification should extend from the sensor to the display device, or the channel isolation device, if the display device is computer based.

The seismic qualification should be in accordance with Reg Guide 1.100, "Seismic Qualification of Electric Equipment for Nuclear Power Plants".

No single failure within either the accident-monitoring instrumentation, its auxiliary supporting features, or its power sources, should prevent the operators from being presented the information necessary for them to determine the safety status of the plant and to bring the plant to, and maintain it in a safe condition following an accident. Redundant or diverse channels should be electrically independent and physically separated from each other and from equipment not classified important to safety.

The instrumentation should be energized from station standby power sources as provided in Reg Guide 1.32, and should be backed up by batteries where momentary interruption is not tolerable.

The instrumentation channels should be available prior to an accident.

The recommendations of the following Reg Guides pertaining to quality assurance should be followed:

Reg Guide 1.28; Reg Guide 1.30; Reg Guide 1.38; Reg Guide 1.58;
Reg Guide 1.64; Reg Guide 1.74; Reg Guide 1.88; Reg Guide 1.123;
Reg Guide 1.144; Reg Guide 1.146.

Continuous indication display should be provided.

Recording of readout information should be provided. Scanning recorders may be used if no significant transient response information is likely to be lost by such devices.

Category 2

The instrumentation should be qualified in accordance with Reg Guide 1.89.

Seismic qualification according to the provisions of Reg Guide 1.100 may be needed provided the instrumentation is part of a safety-related system.

The instrumentation should be energized from a high-reliability power source, not necessarily standby power, and should be backed up by batteries where momentary interruption is not tolerable.

The recommendations of the Reg Guides pertaining to quality assurance listed above, should be followed. It may not be necessary to apply the same quality assurance measures to all instrumentation. The quality assurance requirements implemented should provide control over activities to an extent consistent with the importance to safety of the instrumentation.

Effluent radioactivity monitors, area radiation monitors, and meteorology monitors should be recorded.

Category 3

The instrumentation should be of high-quality commercial grade and should be selected to withstand the specified service environment.

Effluent radioactivity monitors, area radiation monitors, and meteorology monitors should be recorded.

In addition to the above requirements, those instruments designated as Types A, B or C, and Categories 1 and 2, should be specifically identified on the control panels.

Note two general exceptions to the requirement of Reg Guide 1.97:

Seismic qualification of Category 2 equipment conforms to the seismic design of the system it is monitoring.

Environmental qualification complies with the requirements of 10 CFR Part 50, Section 50.49.

Note also that for position monitoring instrumentation of valves and dampers, the valve and damper number is given if the position detection device is not assigned an instrument number.

7.10.3 Regulatory Guide 1.97 Instrumentation

Tables 7.10-1 and 7.10-2 identify the instrument channels which are used to meet the specific requirements of Reg Guide 1.97. Also included are the design category requirements, exceptions taken to those requirements, and a reference to the NRC document which accepts that exception (References 30, 31, 64-73). 00-260

From the list of equipment presented in Tables 7.10-1 and 7.10-2, below are identified and described in detail in Category 1 instruments. In addition, these instruments are identified in the Technical Specifications.

7.10.3.1 Containment Pressure

Two wide range containment pressure channels with recorders in the main control room are provided for the containment. Measurements are done continuously and are made over a pressure range equal to four (4) times the design of steel containment vessel. This instrument indicator system is designed in conformance with NUREG-0737, Item II.F.1.4.

7.10.3.2 Hydrogen Monitors

Two H_2 monitor channels with a range of 0-10% volume continuously monitor the containment environment and are recorded in the control room. This system is designed in conformance with NUREG-0737, II.F.1.6.

7.10.3.3 Containment Vessel Water Level Instruments

Redundant, Class 1E containment vessel water level measurement systems are installed to provide continuous indication of containment water level in the control room. Each system consists of three (3) detector/receiver instrument loops. One of the three detectors, narrow range, is installed in sump "B" and covers the range approximately 3-1/2 inches above sump bottom to 60-inches above sump bottom. The two remaining detectors, wide range, are mounted on the wall adjacent to sump "B". The wide range instruments span from the 697.5-foot level to the 709.5-foot level (709-foot level for Unit 1) and indicate an equivalent capacity of greater than 300,000 gallons (Reference 51). 00-260 00-260

The receivers are located in Train A Event Monitoring Room (Train A) and Train B Event Monitoring Room (Train B), respectively.

The containment vessel water level measurement systems are designed in accordance with NUREG-0737, Item II.F.1.5 and each instrument is tested to the requirements of IEEE-323-1974 and IEEE-344-1975.

7.10.3.4 Inadequate Core Cooling Monitor (ICCM)

The ICCM is designed to warn the operator of the approach to or the existence of an inadequate core cooling situation. The ICCM covers the full range of core cooling from normal operation to a complete core uncovery. The ICCM consists of the integration of three sets of instrumentation: the subcooling margin monitors, the core-exit thermocouples and the reactor vessel water inventory indication systems. The ICCM is designed in accordance with the requirements of NUREG-0737, Item II.F.2 and Generic Letter 82-28.

7.10.3.4.1 RCS Subcooled Margin Monitors

Subcooling Margin is calculated from a validated average of Core Exit Thermocouples (CET's) and Reactor Coolant System Pressure. The primary display is located on the control board via the Emergency Response Computer System CRT. A fully qualified backup display is available in the control room on the Incore Flux Mapping cabinet via the

Inadequate Core Cooling Monitor (Upgraded Reactor Vessel Level Instrumentation System to add display of CET's and calculate Subcooling Margin) per requirements of NUREG-0737 Item II.F.2.

Two redundant trains of CETs along with two redundant trains of Reactor Coolant System Pressure instruments provide Class 1E inputs to both display systems. The SMM range was changed to 200°F subcooling to 35°F superheat when Control Board meters were removed. This range is in accordance with RG 1.97 guidance. 00-260

7.10.3.4.2 Core Exit Thermocouples (CET's)

Fully qualified CETs are provided to the Inadequate Core Cooling Monitors and the Emergency Response Computer System. The CETs are installed to monitor each core quadrant. When used in conjunction with the core inlet temperature data, they provide an indication of the radial distribution of the coolant enthalpy rise. The output of any CET is available through ERCS, which displays the temperature of each CET location. See section 7.6.2.1 for further information. 00-260

7.10.3.4.3 Reactor Vessel Water Inventory Indication

Redundant, Class IE reactor vessel water inventory measurement systems are installed to provide continuous indication of reactor water inventory to the control room. Each system has three differential pressure transmitters in the Auxiliary Building. They sense differential pressure via impulse lines connected to the reactor vessel head, a hot leg, and the bottom of the reactor vessel via a seal table connection. These impulse lines penetrate the reactor containment vessel. They are each filled with water and sealed at each end by instrument internal bellows. Each system has a microprocessor located in Train A Event Monitoring Room (Train A) and Train B Event Monitoring Room (Train B). The microprocessor processes inputs from the differential pressure transmitters, as well as from the following:

- Impulse line hydraulic isolators
- RTDs located on the impulse lines
- Reactor Coolant System wide range pressure transmitter
- Reactor Coolant System temperature
- Reactor Coolant Pumps breaker contacts

The microprocessor calculates a percent level from the above inputs. Both upper range and full range levels are valid calculations when the Reactor Coolant Pumps are not running. When either one or both Reactor Coolant Pumps are running, the dynamic range calculation is valid.

The microprocessor provides an output to the control room display module which indicates a calculated reactor vessel level in percent, both in digital and analog form. The display module indicates which level indications are valid and also provides other indication system diagnostic information.

The reactor vessel water inventory measurement systems are designed in accordance with NUREG-0737, Item II.F.2 and the instruments, microprocessors, and display modules are tested in accordance with IEEE-323-1974 and IEEE-344-1975.

7.10.3.5 Instrument Racks

Instrument racks are provided for post accident monitoring equipment. The racks are installed in the Train A and Train B Event Monitoring Rooms. The racks contain Class IE Event Monitoring equipment and radiation meters.

The instrument racks and Type IE equipment were seismic tested to the anticipated loads, and were designed to provide physical barriers for separation of IE and Non-IE equipment. The racks were evaluated to meet the requirements of IEEE 323-1974 and IEEE 344-1975.

7.10.3.6 High Range Containment Radiation Monitors

The high range containment radiation monitoring system (R-48, R-49) is designed to provide in-containment high-level monitoring capabilities during accident conditions. The system is Class IE and has a calibrated high range of 1 to 10^7 R/hr. The detector assembly is a gamma sensitive ion chamber encased in stainless steel. The system, consists of a detector, readout module and cabling for each train, meets all requirements of NUREG-0578 and subsequent requirements with NUREG 0737 II.F.1.3.

7.10.3.7 RCS Wide Range Temperature

Both RCS hot and cold legs are monitored by wide range RTD's designed to indicate temperatures in the range of 50 - 700°F. These temperature devices and channels are installed as class 1E. Electrically isolated signals are displayed on recorders in the Control Room and indicators on the Hot Shutdown Panel. Installation is in accordance with NUREG-0737 Supplement 1, Reg Guide 1.97.

7.10.3.8 Wide Range Steam Generator Level

Each Steam Generator secondary side is monitored by two wide range level transmitters that indicate a level of 0 - 100%. These level transmitters and channels are installed as class 1E. Electrically isolated signals are displayed using recorders in the Control Room and on indicators on the Hot Shutdown Panels. Installation is in accordance with NUREG-0737 Supplement 1, Reg Guide 1.97. 00-260

One channel of Wide Range Steam Generator Level is also used as an input to the AMSAC/DSS system. See section 7.11 for additional information. 00-260

7.10.3.9 Neutron Flux

Two redundant, Class 1E, environmentally and seismically qualified channels of neutron flux measurement equipment are installed to measure neutron flux over the entire expected range of normal operations. Monitor indication is available in the control room and in the TSC. 00-260

7.10.3.10 Refueling Water Storage Tank Level

Level instrumentation on the refueling water storage tank consists of two seismically qualified channels. 00-260 Each channel provides indication on the control board and two low level alarms. One of those alarms is a normal operating low level and the other is a low-low level alarm. The power supplies for these channels are located in the EM racks.

7.10.3.11 Containment Isolation Valve Position

All containment isolation valves have position indication on the control board to show proper positioning of the valves. Air-operated and solenoid-piloted, air-operated valves are designed to fail to the safest position (fail open or closed) with the loss of air or power. After a loss of power to the motors, motor-operated valves remain in the same position as they were prior to the loss of power.

7.10.3.12 Pressurizer Level

Three seismically and environmentally qualified pressurizer level transmitter instrument channels indicate level in the control room. These three level instrument channels are independently powered from three vital instrument panels which in turn are energized from the two plant batteries. Only two channels are used to support Technical Specification RG 1.97 requirements.

7.10.3.13 Condensate Storage Tank Level

Three Condensate Storage Tanks (CSTs) are located on site. One for Unit 1 and two for Unit 2. Level Instrumentation for the CSTs consists of two channels per unit. Normally, the CSTs are cross-tied and therefore shared by both units.

Train B level signals are indicated on the Unit 1 control boards and Train A level signals are indicated on the Unit 2 control boards. Low and Low-Low level alarms for each train are alarmed in the control room. Level Indicators are also provided which read CST level in feet and gallons.

7.10.3.14 RCS Wide Range Pressure

RCS Wide Range pressure instrumentation channels are provided with indication in the control room. These channels and instruments are environmentally and seismically qualified. Two channels (one per RCS loop) are provided.

7.11 ATWS MITIGATING SYSTEM ACTUATING CIRCUITRY/DIVERSE SCRAM SYSTEM 99027

7.11.1 General Summary 99027

The Code of Federal Regulations was amended on July 26, 1984 to include the 10 CFR Part 50 Section 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants" (ATWS 99027
Rule). The requirements for 10 CFR Part 50 Section 50.62 apply to all commercial light-water-cooled nuclear power plants.

An ATWS is an anticipated operational occurrence (such as loss of feedwater, loss of condenser vacuum, or loss of offsite power) that is accompanied by a failure of the reactor protection system to shut down the reactor. The ATWS Rule requires specific 99027
improvements in the design and operation of commercial nuclear power facilities to reduce the probability of failure to shut down the reactor following anticipated transients and to mitigate the consequences of an ATWS event.

10 CFR Part 50 Section 50.62(c)(1) specifies the basic ATWS mitigation system requirements for Westinghouse plants. Equipment, diverse from the reactor protection system, is required to actuate the auxiliary feedwater system and initiate a turbine trip for ATWS events. In response to 10 CFR Part 50 Section 50.62(c)(1), the Westinghouse 99027
Owners Group developed a set of conceptual ATWS mitigating system actuation circuitry (AMSAC) designs generic to Westinghouse plants. The Westinghouse Owners Group issued Westinghouse Topical Report WCAP-10858, "AMSAC Generic Design Package" which provided information the various Westinghouse Designs.

The NRC Staff reviewed WCAP-10858 and issued a safety evaluation on the subject topical report. In that safety evaluation, the NRC Staff concluded that the generic designs presented in WCAP-10858 adequately met the requirements of 10 CFR Part 50 Section 50.62. Westinghouse issued Revision 1 to WCAP-10858 on August 3, 1987. The AMSAC 99027
system installed at Prairie Island at that time satisfies these ATWS Rule requirements. However, in 1996, Prairie Island selected new AFW pump low discharge pressure setpoints to correct pump runout concerns. A review of the setpoint changes determined that the AFW pumps would trip due to low discharge pressure during specific ATWS events, which is inconsistent with assumptions made in the ATWS analysis performed by Westinghouse.

In 1997, under Design Change 97AF02, NSP decided to install a Diverse Scram System to resolve this ATWS design basis issue and NSP's Nuclear Analysis Department performed analysis based on Prairie Island's approved Reload Safety Evaluation methods and more 99027
conservative acceptance criteria than those applied in the Westinghouse generic ATWS Analysis. The results of this analysis required changes to the process variable inputs used to generate an AMSAC/DSS actuation. It was determined that the new process variable inputs would be steam generator wide range levels and reactor coolant pump breaker position.

7.11.2 Design Basis 99027

The purpose of AMSAC/DSS is to mitigate the effects of a failure of reactor protection to trip the reactor in the event of an anticipated transient. This is required to prevent reactor coolant system pressure from exceeding 3200 psig (ASME Boiler and Pressure Vessel Code Level C service limit). The mitigation is accomplished by tripping the reactor, tripping the turbine, and initiating auxiliary feedwater flow. The specific Prairie Island AMSAC/DSS design, submitted for NRC Staff review by References 55 and 56, satisfies the design criteria, and was reviewed and found acceptable by the NRC Staff in Reference 57. 99027

The Prairie Island AMSAC/DSS (Figure 7.11-1) senses steam generator wide range level and reactor coolant pump breaker position. When a steam generator level decreases below 40% or a reactor coolant pump trips, AMSAC/DSS initiates a diverse reactor trip, a turbine trip and actuates auxiliary feedwater, which in turn isolates steam generator blowdown. AMSAC/DSS actuates on low steam generator level sensed on 2 of 2 level transmitters in either steam generator, or when a loss of any one of the two reactor coolant pumps occurs. 99027

A three-way control switch on the control board is provided to manually actuate the AMSAC/DSS function. The switch causes a diverse reactor trip, a turbine trip, and initiation of auxiliary feedwater flow when placed in the Initiate position. The use of this switch is directed in the plant Emergency Operating Procedures. A reset pushbutton is provided on the control board for use following AMSAC/DSS actuation to reset AMSAC/DSS logic when plant conditions have returned to normal. 99027

7.11.3 Power Sources 99027

The AMSAC/DSS electronics, the reactor coolant pump breaker status circuits, the manual actuation control switch, and the actuation relays are powered from a non-safeguards uninterruptable power supply in the Service Building power distribution system. This uninterruptable power supply is totally independent from the reactor protection system. The power supply has a non-safeguards DC supply backup, and is powered from an AC bus which can be supplied from a non-safeguards diesel generator. This results in a power supply system for AMSAC/DSS which is very secure and is diverse from power sources used in the reactor protection system. 99027

7.11.4 System Electronics and Software Configuration 99027

The AMSAC/DSS is implemented in microprocessor-based instrumentation. The signals from the steam generator level transmitters are input to the feedwater control system, where analog-to-digital conversion takes place. Signal input to AMSAC/DSS occurs via redundant data highways (two coaxial cables) (Figure 7.11-1). 99027

Reactor coolant pump breaker position is wired directly to two separate 120 VAC input cards in the AMSAC/DSS cabinet. Auxiliary 52b contacts in the reactor coolant pump switchgear cubicles are used as the initiating input device. 99027

7.11.5 System Actuation

The AMSAC/DSs is required to trip the reactor, trip the turbine and initiate auxiliary feedwater flow. When the actuation logic formed in the microprocessor unit is satisfied, a logic "1" is supplied to both output cards. Actuation of both output cards (Figure 7.11-1) energizes two separate relay trains, either of which can supply the AMSAC function, while 99027 both are required for the DSS function. The auxiliary feedwater actuation relays provide the 1E interface required by this circuit. All of the AMSAC relays are configured on an energize-to-actuate basis to avoid inadvertent actuation. The specific interface design ensures that when AMSAC/DSS actuation occurs, the action goes to completion.

A control switch located on the Main Control Panel provides manual initiation capabilities for the Control Room operators. The manual initiation signal bypasses the AMSAC/DSS logic to directly energize the actuation relays. Once a manual initiation has occurred, the 99027 actuating relays are sealed-in by a relay contact. A second control pushbutton is used to reset the system logic after plant conditions are restored to normal.

7.11.6 Design Considerations

AMSAC/DSS performs a reactor protection function; however, it is not part of the reactor protection system and its design is such that control signals are used for protective actions. which is not in accordance with the design guidance of USAR Sections 7.4.1.2.6 and 8.7.5. The nature of the AMSAC/DSS design guidance requires this non-standard design. 99027 Reference 56 discusses the design considerations for AMSAC/DSS systems which include diversity, independence, environmental qualification, testability and quality assurance. This reference states that redundancy, seismic qualification, and physical separation from existing reactor protection system are not required.

A reactor trip, a turbine trip and auxiliary feedwater pump start are required AMSAC/DSS functions, with securing of blowdown and sampling as recommended outputs. Blowdown 99027 secures following an auxiliary feedwater actuation from any source; therefore, no AMSAC/DSS output is needed for this function. Steam Generator sampling flow is typically an insignificant source of inventory loss; no automatic action for securing sampling is necessary.

The diverse reactor trip is accomplished using a new circuit board in each of the three rod control system power cabinets. The new circuit card, when actuated, reduces the rod control internal Vref signal to a low voltage which causes the system firing cards to decrease the current to each of the gripper coils for each rod. The decrease in current allows the grippers to disengage, dropping the rods. Each card is connected with the Vref 99027 signal to the Stationary grippers along the Vref signal to the Movable grippers for all three groups controlled by that power cabinet.

Automatic bypass of the AMSAC/DSS has been eliminated in the NSP design. Bypass capabilities are provided by a new three-position switch on the Main Control Board, which 99027 will be administratively controlled by plant operating procedures. Continuous indication in the Control Room is provided when the AMSAC/DSS is blocked for surveillance testing to indicate the system is unavailable.

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56. Letter, J P Sorensen (NSP) to USNRC, " Response to July 2, 1998, Request for Additional Information on License Amendment Request dated February 27, 1998, ATWS Mitigating System Actuating Circuitry/Diverse Scram System," July 14, 1998.

57. Letter, Tae Kim (USNRC) to R O Anderson (NSP), "Issuance of Amendments RE: Modification to ATWS Mitigating System Actuating Circuitry (TAC Nos. MA1675 and MA1676)," September 22, 1998.

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60. Letter, L O Mayer (NSP) to USNRC, “Post TMI Requirements - NUREG-0737,” December 30, 1980.

61. Letter, L O Mayer (NSP) to USNRC, “Additional Information for Resolution of NUREG-0737, Item II.E.4.2, Position 5, Minimum Containment Pressure Setpoint,” August 26, 1981.

62. Letter, Robert A. Clark (NRC) to L O Mayer (NSP), “TMI Task Action Plan Item II.E.4.2(5) Containment Pressure Setpoint; Prairie Island Nuclear Generating Plant Units 1 and 2,” December 2, 1981.

63. T. Cecchi, C. K. Potaris, “Setpoint Study for Northern States Power Company Units No. 1 and No. 2, Control and Protection Analysis”, WCAP-7721, August 1986.

64. Letter, D M Musolf to Director NRR, “Information Related to NUREG-0737, Item II.B.3, Post Accident Sampling System”, December 3, 1982.

65. USNRC to Licensees, “Supplement 1 to NUREG-0737 - Requirements for Emergency Response Capability (Generic Letter No. 82-33)”, December 17, 1982.

66. Letter, D M Musolf to Director NRR, “Supplement 1 to NUREG-0737 - Response to Generic Letter 82-33”, April 15, 1983.

67. Letter, D M Musolf to Director NRR, “NUREG-0737 Supplement 1 - Generic Letter 82-33 Regulatory Guide 1.97 - Application to Emergency Response Facilities”, September 15, 1983. 00-261

68. Letter D M Musolf to Director NRR, “Additional Information Related to Conformance with Regulatory Guide 1.97, Revision 2”, January 18, 1985.

69. Letter, James R. Miller (NRC) to D M Musolf, “Safety Evaluation and Request for Additional Information Generic Letter 82-28; NUREG-0737 Item II.F.2, Inadequate Core Cooling Instrumentation”, May 13, 1985.

70. Letter, D M Musolf to Director NRR, “Additional Information Related to Conformance with Regulatory Guide 1.97, Revision 2”, June 6, 1985.

71. Letter, D M Musolf to Director NRR, “Request for Extension of Time for Completing NUREG-0737 Supplement 1 Requirements”, November 27, 1985.

72. Letter, D M Musolf to Director NRR, “Additional Information on Reg. Guide 1.97”, March 6, 1989.

73. Letter, Marsha Gamberoni (USNRC) to Roger O. Anderson, "Prairie Island Nuclear Generating Plant Units 1 and 2 - Instrumentation to Follow the Course of an Accident (Regulatory Guide 1.97 MPA A-17, TAC No.s M51122 and M51123)", April 27, 1993. 00-261

74. T. Morita, L.R. Sherpereel, K.J. Dzikowski, R.E. Radcliffe, D.M. Lucoff, "Topical Report, Power Distribution Control and Load Following Procedures", WCAP-8385, September 1974. 00-274

TABLE 7.4-1 LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

	REACTOR TRIP	COINCIDENCE CIRCUITRY AND INTERLOCKS	COMMENTS
1.	Manual	1/2, no interlocks	
2.a	High Neutron Flux (low setpoint)	2/4, low setting interlocked with P10	Manual block and automatic reset of low setting by P10, Table 7.4-3.
2.b	Power Range High Neutron Flux (high setpoint)	2/4, no interlocks	
3.	Overtemperature ΔT	2/4 no interlocks	
4.	Overpower ΔT	2/4, no interlocks	
5.	Pressurizer Low Pressure	2/4, interlocked with P7	
6.	Pressurizer High Pressure	2/3, no interlocks	
7.	Pressurizer High Water Level	2/3, interlocked with P7	
8.a	Reactor Coolant Low Flow	2/3 per loop, interlocked with P7 and P8*	Both loops blocked below P7. Single loop blocked below P8

* P7 and P8 are set at approximately the same point.

TABLE 7.4-1 LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

	REACTOR TRIP	COINCIDENCE CIRCUITRY AND INTERLOCKS	COMMENTS
8.b	Monitored electrical supply for Reactor coolant pumps		
$8.b_1$	RCP Bus Undervoltage	2/2 buses sensed by 1/2 sensors per bus, Interlocked with P7	Blocked below P7
$8.b_2$	RCP Breakers Open	Interlocked with P7 and P8	Both loops blocked below P7. Single loop blocked below P8
$8.b_3$	RCP Bus Underfrequency	2/2 buses sensed by 1/2 sensors per bus, trips both RCP breakers. Reactor trip is then via $8.b_2$	
9.	Safety Injection (actuation) signal(S)	Low pressurizer pressure (2/3); or 2/3 high containment pressure or manual 1/2; or 2/3 low steam pressure from either loop.	An S Signal results in the following actions: Trips - main feedwater pumps, closes all feedwater control valves, trips reactor, actuates auxiliary feedwater pumps, isolates steam lines in coincidence with other signals. (See section 7.4.2.2)

TABLE 7.4-1 LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

	REACTOR TRIP	COINCIDENCE CIRCUITRY AND INTERLOCKS	COMMENTS
10.	Turbine - generator trip	2/3 low auto stop oil pressure or 2/2 stop valve closure indication both interlocked with P9.	
11.	Low feedwater flow	Deleted	Deleted by Modification 87Y785, which uses signal validation to satisfy protection/control interface
12.	Low-low steam generator water level	2/3, either loop.	
13.	Intermediate range nuclear flux	1/2, manual block permitted by P10.	Manual block and automatic reset.
14.	Source range nuclear flux	1/2, manual block permitted by P6, interlocked with automatic block by P10.	Manual block and automatic reset.
15.	Power range high positive neutron flux rate	2/4, no interlocks.	
16.	Power range high negative neutron flux rate	2/4, no interlocks.	

TABLE 7.4-1 LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

CONTAINMENT ISOLATION ACTUATION	COINCIDENCE CIRCUITRY AND INTERLOCKS	COMMENTS
17. Safety Injection Signal	See Item 9.	
18. Manual Containment Isolation	One out of two (1/2)	
19. Containment Ventilation Isolation Actuation	High activity signal, from air particulate detector or radiogas detector or 1/2 manual by containment isolation or 2/2 manual by containment spray actuation or safety injection.	
ENGINEERED SAFETY FEATURES ACTUATION		
20. Safety Injection signal (S)	See Item 9	
21. a. Containment spray signal (P)	Three 1/2 (Hi - Hi) containment pressure containment spray in coincidence.	
b. Manual spray	Two out of two (2/2)	
22. Containment air cooling signal	Safety injection signal initiates starting of all fans, transfers containment fan coils from chilled water to cooling water and closes the CRDM coil supply and return valves in accordance with the Safety Injection Starting Sequence.	

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TABLE 7.4-1 LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

STEAM LINE ISOLATION ACTUATION		COMMENTS
23. Steam Flow	Coincidence of Hi-Hi steam flow (1/2) in the respective line and safety injection signal or: Coincidence of (1/2) Hi steam flow in the respective line and safety injection signal and (2/4) low-low T_{avg}	
24. Hi Containment pressure, Main Steam Isolation Set Point	2/3 Hi containment pressure main steam isolation signal	
25. Manual, per steam loop	1/1 per steam line	
AUXILIARY FEEDWATER ACTUATION		
26. Turbine driven pump	Low-Low level in either steam generator; or loss of voltage on 2/2 4KV volt buses or a trip of 2/2 main feedwater pumps; or safety injection, or AMSAC system actuation.	The AMSAC system AFW actuation is not a safeguards/protection required function.
27. Motor driven pump	Low-Low level in either steam generator; or trip of 2/2 main feedwater pumps; or safety injection signal as modified by a Load Rejection/Restoration sequence, or AMSAC system actuation	The AMSAC system AFW actuation is not a Safeguards protection required function.

TABLE 7.4-1 LIST OF REACTOR TRIPS & CAUSES OF ACTUATION OF ENGINEERED SAFETY FEATURES, CONTAINMENT AND STEAM LINE ISOLATION & AUXILIARY FEEDWATER

MAIN FEEDWATER ISOLATION	COINCIDENCE CIRCUITRY AND INTERLOCKS	COMMENTS
28. Close main feedwater control valves	1) S Signal 2) Reactor trip coincident with low Tavg 3) 2/3 Hi-Hi steam generator level closes the valves to the effected steam generator.	
29. Close bypass feedwater control valves and trip main feedwater pumps	1) S Signal 2) 2/3 Hi-Hi Steam Generator Level	

NOTE 1: Definition of "S", "T", and "P" signals.

Signal	Action
"S"	safety injection signal
"T"	containment isolation signal
"P"	containment spray signal

TABLE 7.4-3 - REACTOR TRIP INTERLOCK PERMISSIVES

Designation	Function	Required Input
P6	Allows Source Range Reactor Trip to be manually blocked	1 of 2 Intermediate Range nuclear flux ≥ setpoint allows manual block. 2 of 2 Intermediate Range nuclear flux < setpoint defeats block.
P7(1)	At low power, blocks: - Two primary loop loss of flow trip - Undervoltage on RCP buses trip - Pressurizer low pressure trip - Pressurizer high level trip	3 of 4 Power Range nuclear flux < setpoint <u>and</u> 2 of 2 Turbine 1st Stage Pressure < setpoint blocks trips. 2 of 4 Power Range nuclear flux (P10) ≥ setpoint <u>or</u> 1 of 2 Turbine 1st Stage Pressure (P13 on Unit 2 only) ≥ setpoint enables trip.
P8(1)	At low power, blocks: - Single primary loop loss of flow trips	3 of 4 Power Range nuclear flux < setpoint blocks trip. 2 of 4 Power Range nuclear flux ≥ setpoint enables triip.
P9	At low power, blocks: - Reactor trip with turbine trip	3 of 4 Power Range nuclear flux < setpoint blocks trip. 2 of 4 Power Range nuclear flux ≥ setpoint enables triip.
P10	Allows manual block of: - Intermediate Range trip and rod stop - Power Range low setpoint trip Automatically provides P6 back-up An input to P7	2 of 4 Power Range nuclear flux ≥ setpoint allows manual block. 3 of 4 Power Range nuclear flux < setpoint defeats block.
P13 (Unit 2 only)	An input to P7	2 of 2 Turbine 1st Stage Pressure < setpoint blocks trip. 1 of 2 Turbine 1st Stage Pressure ≥ setpoint enables trip.

(1) P7 and P8 are set at approximately the same point.

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TABLE 7.4-4 PROCESS INSTRUMENTATION FOR RPS & ESF ACTUATION

Parameter	Transmitter Sensors	Read-Out*	Power	Prot/Safeguards Use	Taps	
Reactor Coolant Temperature	8 RTD's	C.B. Meter (T_{avg}, ΔT)	Ext.	ΔT trips, T_{avg} permissives	1 each	99019
Pressurizer Pressure	4 Transmitters	C.B. Meter	Ext.	Hi/Lo Pressure Trips, SIS	3 (Top Level) One Shared	
Pressurizer Level	3 ΔP Transmitters	C.B. Meter	Ext.		3 pairs	99019
Steam Flow	4 ΔP Transmitters	C.B. Meter	Ext.	Steamline Isolation	1 Pair Each,	
Steam Pressure	6 Transmitters	C.B. Meter	Ext.	SIS	1 Each	
Steam Generator Level	6 ΔP Transmitters	C.B. Meter	Ext.	Low Level Trip Feedwater Isolation	1 Pair Each	
Reactor Coolant Flow	6 ΔP Transmitters	C.B. Meter	Ext.	Low Flow Trip	1 High Pressure Shared/Loop, 1 Low Pressure Each	
Containment Pressure	6 Transmitters	C.B. Meter	Ext.	SIS (3) Steam Line Isolation Spray (3+3)	4 shared	99019
Turbine 1st Stage Pressure	2 Transmitters	C.B. Meter	Ext.	Set Point Programs and Turbine Power Permissives	1 Each	

* C.B. is Control Board

TABLE 7.4-5 POST-ACCIDENT EQUIPMENT (INSIDE CONTAINMENT) OPERATIONAL REQUIREMENTS

Equipment Name	Operating Mode	Required Duration of Operation	Range	Design Duration of Operation	Environmental Testing
CATEGORY I - INSTRUMENTATION					
*Pressurizer pressure channels (4)	Continuous	1/2 hr (for S.I. Initiation)	1700 - 2500 psi	2 hrs	Required
*Pressurizer level channels (3)	Continuous	1/2 hr	0 - 100%	2 hrs	Required
*Containment Pressure (Outside Containment)	Continuous	3 mo	0 - 30 psi		N/A
*High-head flow (2) (Outside Containment)	Continuous	5 min	0 - 1500 gpm	2 hrs (min)	N/A
CATEGORY 2 - VALVES & FANS					
Containment Isolation valves	Operate on signal	5 min		1/2 hr minimum	Required
Containment air cooling fan dampers (4)	Open on signal	5 min		1/2 hr minimum	Required
Safeguard equipment power control and instrument cable	Continuous	3 mo		Available for 1 year	Required
Containment fan coil fans (4)	Continuous	2 mo		Available for 1 year	Required

* Performs post-accident montoring (PAM) function. See Section 7.10 for further details of PAM.

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TABLE 7.4-6 GENERIC LETTER 83-28, SALEM ATWS EVENTS ACTION ITEM SUMMARY

(Page 1 of 2)

Item	Description	NRC Safety Evaluation Date
1.1	POST TRIP REVIEW (Program Description and Procedure)	8/5/85
1.2	POST TRIP REVIEW (Data and Information Capability)	5/27/86
2.1 (1)	EQUIPMENT CLASSIFICATION (Reactor Trip System Components)	7/11/86
2.1 (2)	VENDOR INTERFACE (Reactor Trip System Components)	12/30/86
2.2 (1)	EQUIPMENT CLASSIFICATION (Program for all Safety-Related Components)	10.24/89
2.2 (2)	VENDOR INTERFACE (Program for all Safety-Related Components)	- - - -*
3.1	POST-MAINTENANCE TESTING (Reactor Trip System Components)	
3.1.1	Review of Test and Maintenance Procedures and Technical Specifications to Assure Post-Maintenance Operability	5/13/85
3.1.2	Review of Vendor and Engineering Recommendations	5/13/85
3.1.3	Review of Technical Specification Post-Maintenance Test Requirements	10/18/85
3.2	POST-MAINTENANCE TESTING (All Other Safety-Related Components)	
3.2.1	Review of Test and Maintenance Procedures and Technical Specifications to Assure Post-Maintenance Operability	5/13/85
3.2.2	Review of Vendor and Engineering Recommendations	5/13/85
3.2.3	Review of Technical Specifications Post-Maintenance Maintenance Test Requirements	10/18/85

*NRC SER not issued

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TABLE 7.4-6 GENERIC LETTER 83-28, SALEM ATWS EVENTS ACTION ITEM SUMMARY

(Page 2 of 2)

Item	Description	NRC Safety Evaluation Date
4.1	REACTOR TRIP SYSTEM RELIABILITY (Vendor Related Modifications)	5/13/85
4.2	REACTOR TRIP SYSTEM RELIABILITY (Preventative Maintenance and Surveillance Program for Reactor Trip Breakers)	
4.2.1	Planned Program of Preventative Maintenance	10/17/85
4.2.2	Trending of Parameters Affecting Operation and Measured During Testing to Forecast Degradation of Operability	10/17/85
4.2.3	Life Testing of Trip Breakers	- - -*
4.2.4	Periodic Replacement of Breakers or Components Consistent with Demonstrated Life Cycles	- - -*
4.3	REACTOR TRIP SYSTEM RELIABILITY (Automatic Actuation of Shunt Trip Attachment for Westinghouse Plants)	8/10/83 2/21/85 6/26/85
4.4	Not Applicable to Prairie Island	
4.5	REACTOR TRIP SYSTEM RELIABILITY (System Functional Testing)	
4.5.1	Testing of Diverse Trip Features	5/13/85
4.5.2	Periodic On-Line Testing	3/30/87
4.5.3	Review of Existing Intervals for On-Line Functional Testing Required by Technical Specifications	6/7/89

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*NRC SER not issued, Supplement 1 to Generic Letter 83-28, issued October 7, 1992, informed licensees that the actions of Items 4.2.3 and 4.2.4 are no longer needed. 95046

TABLE 7.5-1 RADIATION MONITORING SYSTEM CHANNEL SENSITIVITIES

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Channel Number	Instrument Channel Name	Type	Sensitivity	Range	Detecting Medium	Qualified Detecting Conditions Temp Range (°F)
R-1	Control Room Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
1R-2, 2R-2	Containment Vessel Area monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	30 to 120
R-3	Radiochemistry Laboratory Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
R-4	Charging Pump Room Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
R-5	Spent Fuel Pool Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
R-6	Sampling Room Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
1R-7, 2R-7	Incore Seal Table Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	30 to 120
R-8	Waste Gas Valve Gallery Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
1R-9, 2R-9	Reactor Coolant Letdown Line Area Monitor	GM Tube	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
1R-11, 2R-11	Containment or Containment Purge Vent-Air Particulate Monitor	Scintillation Detector (NaI)	10^{-9} uCi/cc based on I-131	10^{-9} to 10^{-6} uCi/cc	Air	30 to 120
1R-12, 2R-12	Containment or Containment Purge Vent-Radioactivity Gas Monitor	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	30 to 120

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TABLE 7.5-1 RADIATION MONITORING SYSTEM CHANNEL SENSITIVITIES

Channel Number	Instrument Channel Name	Type	Sensitivity	Range	Detecting Medium	Qualified Detecting Conditions Temp Range (°F)
1R-15, 2R-15	Condenser Air Ejector Gas Monitor	Scintillation Detector (NaI)	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	40 to 120 00-290
R-16	Containment Fan Coil Cooling Water Discharge Monitor	Scintillation Detector (NaI)	10^{-5} uCi/cc based on Co-60	10^{-5} to 10^{-2} uCi/cc	Water	40 to 160
R-18	Waste Disposal System Liquid Effluent Monitor	Scintillation Detector (NaI)	10^{-5} uCi/cc based on Co-60	10^{-5} to 10^{-2} uCi/cc	Water	60 to 160
1R-19, 2R-19	Steam Generator Blowdown System Liquid Sample Monitor	Scintillation Detector (NaI)	10^{-5} uCi/cc based on Co-60	10^{-5} to 10^{-2} uCi/cc	Water	60 to 160
R-21	Circulating Water Discharge Monitor	Scintillation Detector (NaI)	2 x 10^{-7} uCi/cc based on Co-60	2 x 10^{-7} to 10^{-4} uCi/cc	Water	32 to 120
1R-22, 2R-22	Shield Building Vent Gas Monitor	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	30 to 120 00-290
R-23	Control Room Air Supply Monitor A	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	50 to 120
R-24	Control Room Air Supply Monitor B	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	50 to 120
R-25	Spent Fuel Pool Air Monitor	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	40 to 120 00-290
R-26	Residual Heat Removal Cubicle Air Monitor	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	30 to 160

TABLE 7.5-1 RADIATION MONITORING SYSTEM CHANNEL SENSITIVITIES

Channel Number	Instrument Channel Name	Type	Sensitivity	Range	Detecting Medium	Qualified Detecting Conditions Temp Range (°F)
R-27	Residual Heat Removal Cubicle Air Monitor	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	30 to 160
R-28	New Fuel Pit Criticality Area Monitor	Current Mode Scintillation Detector (NaI)	1 mR/hr	1 mR/hr to 100 R/hr	Air	50 to 120
R-29	Shipping and Receiving Area Monitor	Current Mode Scintillation Detector (NaI)	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
1R-30, 2R-30	Auxiliary Building Vent Gas Monitor B	GM Tube	5×10^{-7} uCi/cc based on Kr-85	5×10^{-7} to 10^{-4} uCi/cc	Air	40 to 160
R-31	Spent Fuel Pool Air Monitor	GM Tube	10^{-6} uCi/cc based on Kr-85	10^{-6} to 10^{-3} uCi/cc	Air	40 to 120
R-32	Rad Waste Building Contract Station Monitor	Current Mode Scintillation Detector (NaI)	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
R-33	Rad Waste Second Floor Area Monitor	Current Mode Scintillation Detector (NaI)	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120
R-35	Rad Waste Treatment Building Vent Monitor	GM Tube	5×10^{-7} uCi/cc based on Kr-85	5×10^{-7} to 10^{-4} uCi/cc	Air	30 to 160
R-36	Charging Pump Room Area Monitor	Current Mode Scintillation Detector (NaI)	0.1 mR/hr	0.1 mR/hr to 10 R/hr	Air	50 to 120

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TABLE 7.5-1 RADIATION MONITORING SYSTEM CHANNEL SENSITIVITIES

Channel Number	Instrument Channel Name	Type	Sensitivity	Range	Detecting Medium	Qualified Detecting Conditions Temp Range (°F)
1R-37, 2R-37	Auxiliary Building Vent Gas Monitor A	GM Tube	5×10^{-7} uCi/cc based on Kr-85	5×10^{-7} to 10^{-4} uCi/cc	Air	40 to 160
R-38	Containment Fan Coiling Cooling Water Discharge Monitor	Scintillation Detector (NaI)	10^{-5} uCi/cc based on Co-60	10^{-5} to 10^{-2} uCi/cc	Water	40 to 160
1R-39, 2R-39	Component Cooling System Liquid Monitor	Scintillation Detector (NaI)	10^{-5} uCi/cc based on Co-60	10^{-5} to 10^{-2} uCi/cc	Water	30 to 160
R-41	Waste Gas High Activity Loop Inventory Monitor	GM Tube	10^{-6} uCi/cc based on Kr85	10^{-6} to 10^{-3} uCi/cc	Air	40 to 120
R-42	Heating Boiler Deaerator Rad Monitor	Scintillation Detector (NaI)	10^{-6} uCi/cc based on Co-60	2×10^{-7} to 10^{-4} uCi/cc	Water	
1R-48, 2R-48	High Range Containment Rad Monitor Train B	ION Chamber	1R/hr	1 to 10^{8} R/hr	Air	Max 350
1R-49, 2R-49	High Range Containment Rad Monitor Train A	ION Chamber	1R/hr	1 to 10^{8} R/hr	Air	Max 350
1R-50 2R-50	High Range Shield Building Vent Gas monitor	ION Chamber	0.1 mr/hr	10^{-2} to 10^{5} uCi/cc	Air	-4 to 140
1R-51, 2R-51	Loop A Steam Line Radiation Monitor	GM Tube	1 mr/hr	5×10^{-1} to 3×10^{4} uCi/cc	Air	-20 to 140
1R-52, 2R-52	Loop B Steam Line Radiation Monitor	GM Tube	1 mr/hr	5×10^{-1} to 3×10^{4} uCi/cc	Air	-20 to 140

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TABLE 7.5-1 RADIATION MONITORING SYSTEM CHANNEL SENSITIVITIES

Channel Number	Instrument Channel Name	Type	Sensitivity	Range	Detecting Medium	Qualified Detecting Conditions Temp Range (°F)
1R-53, 2R-53	Safety Injection Pump Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-54, 2R-54	Containment Spray Pump Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-55, 2R-55	Auxiliary Building 695 East (U2 West) Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-56, 2R-56	Auxiliary Building 695 West (U2 East) Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-57, 2R-57	Auxiliary Building 715 East (U2 West) Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-58, 2R-58	Auxiliary Building 715 West (U2 East) Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-59, 2R-59	Auxiliary Building 715 Penetration/Letdown Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-60, 2R-60	Auxiliary Building 735 Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-61, 2R-61	Loop A Steam Line Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-62, 2R-62	Auxiliary Building 755 East (U2 West) Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122

TABLE 7.5-1 RADIATION MONITORING SYSTEM CHANNEL SENSITIVITIES

Channel Number	Instrument Channel Name	Type	Sensitivity	Range	Detecting Medium	Qualified Detecting Conditions Temp Range (°F)
1R-63, 2R-63	Auxiliary Building 755 West (U2 East) Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
1R-64, 2R-64	Turbine Building 735 Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
R-65	Operation Support Center Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
R-66	D1 Diesel Room Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
R-67	I&C Shop Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
R-68	Technical Support Center Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
R-69	Guardhouse Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 122
2R-72	D6 Cable Spreading Room Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 130
2R-73	Bus 26 Switchgear Room Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 130
2R-74	480V Bus 221/222 Switchgear Area Monitor	Ionization Chamber	10^{-4} R/hr	10^{-4} - 10^{4} R/hr	Air	0 to 130

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TABLE 7.5-3 TYPE AND NUMBER OF PORTABLE RADIATION SURVEY INSTRUMENTS AVAILABLE FOR ROUTINE USE EXCLUDING EMERGENCY EQUIPMENT

Number*	Type
8	Ionization Chamber (of which at least two have a range of 10^3 Rem per hour)
4	Geiger-Meuller Survey Meter
1	Alpha Survey Meter
1	Neutron Survey Meter
3	Air Particulate Sampler

*Not counting emergency equipment

TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
A.1	1	1P-709 (EMA1) 1P-710 (EMB1)	Reactor Coolant System Pressure	No Exception	SER 10/18/85
A.2	1	1L-920 (EMA1) 1L-921 (EMB1)	Refueling Water Storage Tank Level	No Exception	SER 10/18/85
A.3	1	1L-460 (EMB1) 1L-487 (EMA1) 1L-470 (EMA1) 1L-488 (EMB1)	Steam Generator Level	No Exception	SER 10/18/85 NSP Letter 3/6/89
B.1.1	1	1N-51 1N-52	Neutron Flux	No Exception	#
B.1.2	3	Channel # Same as Rod #	Control Rod Position	No Exception	#
B.1.3	3	70800	Reactor Coolant System Soluble Boron Concentration	Range NSP Letter 12/3/82	SER 10/18/85
B.1.4	3^ See B.2.2	See B.2.2	Reactor Coolant System Cold Leg Temperature	See B.2.2	See B.2.2
B.2.1	1	1T-450A (EMA1) 1T-451A (EMB1)	Reactor Coolant System Hot Leg Temperature	Range	SER 10/18/85
B.2.2	1	1T-450B (EMA1) 1T-451B (EMB1)	Reactor Coolant System Cold Leg Temperature	Range	SER 10/18/85
B.2.3	1	See A.1	Reactor Coolant System Pressure	See A.1	See A.1

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
B.2.4	3^ See C.1.1	See C.1.1	Core Exit Temperature	See C.1.1	See C.1.1
B.2.5	1	1L-750 1L-763 1L-752 1LM-750 1L-753 1LM-760 1L-760 1T-750 1L-762 1T760	Coolant Level in Reactor	No Exception	SER 5/8/86
B.2.6	2	1LM-750 1LM-760 1P-751 1P-761	Degrees of Subcooling	No Exception	SER 5/13/85 & SER 5/8/86
B.3.1	1	See A.1	Reactor Coolant System Pressure	See A.1	See A.1
B.3.2	2	1L-725 (EMA3) 1L-726 (EMB3)	Containment Sump Water Level	No Exception	#
	1	1L-727 (EMA3) 1L-728 (EMB3)	Containment Sump Wide Range Water Level	No Exception	#
B.3.3	1	1P-717 (EMA1) 1P-718 (EMB1)	Containment Pressure	No Exception	#

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #		VARIABLE	EXCEPTIONS	ACCEPTANCE
B.4.1	1	CV-31019	CV-31545	Containment Isolation Valve Position	Display by SPDS	
		CV-31022	CV-31546			
		CV-31092	CV-31621			
		CV-31221	CV-31622			
		CV-31252	CV-31740			
		CV-31318	CV-31741			
		CV-31319	CV-31750			
		CV-31321	MV-32023			
		CV-31325	MV-32024			
		CV-31326	MV-32044			
		CV-31327	MV-32058			
		CV-31339	MV-32095			
		CV-31402	MV-32166			
		CV-31403	MV-32199			
		CV-31434	MV-32400			
		CV-31435	MV-32401			
		CV-31436	MV-32402			
		CV-31437	MV-32403			
		CV-31438	MV-32404			
		CV-31439	MV-32405			
		CV-31440				
B.4.2	1	See B.3.3		Containment Pressure	See B.3.3	See B.3.3

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #		VARIABLE	EXCEPTIONS	ACCEPTANCE
C.1.1	1	13234 13235 13237 13238 13239 13240 13241 13242 13243 13245 13246 13247 13248 13249 13250 13251 13252 13253	13255 13256 13258 13259 13260 13261 13262 13263 13264 13265 13266 13267 13268 13269 13270 13271 13272	Core Exit Temperature	Replaced with qualified system consisting of 16 fully qualified CET readouts on the backup display (ICCM)	SER 5/8/86
C.1.2	1	By Sample		Radioactivity Concentration in Circulating Primary Coolant	Acceptable Alternate Instrumentation as defined by NSP letter dated 12/3/82.	SER 10/18/85
C.1.3	3	By Sample		Analysis of Primary Coolant (Gamma Spectrum)	No Exceptions	#
C.2.1	1	See A.1		Reactor Coolant System Pressure	See A.1	See A.1
C.2.2	1	See B.3.3		Containment Pressure	See B.3.3	See B.3.3
C.2.3	2	See B.3.2		Containment Sump Water Level	See B.3.2	See B.3.2

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
C.2.4	3^ See E.1.1	See E.1.1	Containment Area Radiation	See E.1.1	See E.1.1
C.2.5	3^ See E.3.1.4	See E.3.1.4	Effluent Radioactivity Noble Gas Effluent from Condenser Air Removal System Exhaust	See E.3.1.4	See E.3.1.4
C.3.1	1	See A.1	Reactor Coolant System Pressure	See A.1	See A.1
C.3.2	1	1X-719 (EMA3) 1X-721 (EMB3)	Containment Hydrogen Concentration	No Exception	SER 10/18/85
C.3.3	1	See B.3.3	Containment Pressure	See B.3.3	See B.3.3
C.3.4	2	1R-12 1R-22 1R-50	Containment Effluent Radioactivity - Noble Gas Effluent from Identified Release Points	Range EQ - located in mild environment	SER 10/18/85
C.3.5	2	1R-53 1R-59 1R-54 1R-60 1R-55 1R-61 1R-56 1R-62 1R-57 1R-63 1R-58	Radiation Exposure Rate - Inside Buildings or Areas in Direct Contact with Containment	Power Supply, Control Room display, TSC readout, EQ, Seismic & QA	SER 10/18/85
C.3.6	2	1R-30 (Rack 21) 1R-37 (Rack 11) 1R-50 1R-22	Effluent Radioactivity - Noble Gases Inside Buildings or Areas in Direct Contact with Containment	Range EQ - located in mild environment Seismic - 1R-50 only	SER 10/18/85 Generic Response III*
D.1.1	2	1F-626 (Process Rack 1SA) 1F-928 (Process Rack 1SD)	Residual Heat Removal System Flow	Seismic & QA	Generic Response III*

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.1.2	2	1T-627 (Process Rack 1SA)	Residual Heat Removal Heat Exchanger Outlet Temperature	Range, Seismic, EQ & QA	SER 10/18/85 Generic Response III*
D.2.1	3	1P-936 1P-937 1P-940 1P-941	Accumulator Tank Press	Non-safety	SER 4/27/93
	3	1L-934 1L-935 1L-938 1L-939	Accumulator Tank Level	Non-safety	SER 4/27/93
D.2.2	2	MV-32071 MV-32072	Accumulator Isolation Valve Position	EQ - locked open valves exempt per 10CFR50.49. QA - status light, open indication only	
D.2.3	2	1F-110 1F-113	Boric Acid Charging Flow	Seismic, EQ & QA	Generic Response III*
D.2.4	2	1F-924 1F-925	Safety Injection Flow	No Exception	#
D.2.6	2^ See A.2	See A.2	Refueling Water Storage Tank level	See A.2	See A.2
D.3.1	3	4625501 4625502 4625601 4625602	Reactor Coolant Pump Status	Use RCP Breaker status and KW Monitor instead of current indication	SER 10/18/85

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.3.2	2	1X-443 1X-444 1X-445 CV-31231 CV-31232	Primary System Safety Relief Valve Position and Flow	EQ, Seismic & QA	Generic Response III* and Detectors are EQ
D.3.3	1	1L-426 1L-427 1L-428	Pressurizer Level	Range	SER 10/18/85
D.3.4	2	1PZRHTRA/XD 1PZRHTRB/XD	Pressurizer Heater Status	QA, Seismic & EQ KW Monitor Instead of current	SER 10/18/85 Generic Response III*
D.3.5	3	1L-442	Quench Tank (PRT) Level	No Exception	#
D.3.6	3	1T-439	Quench Tank (PRT) Temperature	Range	SER 10/18/85
D.3.7	3	1P-440	Quench Tank (PRT) Pressure	No Exception	#
D.4.1	1	See A.3	Steam Generator Level	See A.3	See A.3
D.4.2	2	1P-468 1P-469 1P-482 1P-478 1P-479 1P-483	Steam Generator Pressure	No Exception	#

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #		VARIABLE	EXCEPTIONS	ACCEPTANCE
D.4.3	2	1F-464 1F-474 1F-475 1F-465 1F-810 1F-811 1F-812 1F-813	1F-814 1F-815 1F-816 1F-817 1F-818 1F-819 1F-820	Main Steam Flow	No Exception	
	2	1Z-825 1Z-826 1Z-830	1Z-831 1Z-832 1Z-833	Safety/Relief Valve Positions	QA, Seismic & EQ	Generic Response III*
	2	1R-51 1R-52		Steam Line Radiation	QA, Seismic & EQ	Generic Response III*
D.4.4	3	1F-466 1F-467 1F-476 1F-477		Main Feedwater Flow	No Exception	#
D.5.1	2	23122 23127		Auxiliary Feedwater Flow	EQ, Seismic & QA	SER 10/18/85 Generic Response III*
D.5.2	1	1L-723 (EMA1) 1L-724 (EMB1)		Condensate Storage Tank Level	EQ - Located in mild environment	SER 10/18/85

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.6.1	2	MV-32096 MV-32097 MV-32098 MV-32099 MV-32103 MV-32105	Containment Spray System Valve Positions	Uses Alternate Instrumentation for Containment Spray Flow. See also A.2, D.1.2, and D.6.4.	SER 10/18/85 NRC Letter 6/1/87
	2	24061	Caustic Addition Standpipe Level		
	2	4600801 4600802 4600901 4600902	Containment Spray Pump on/off Status		
D.6.2	2	15442 15443 15447 15448 15449 15484	Heat Removal by the Containment Fan Heat Removal System	QA, Seismic & EQ	Generic Response III *
D.6.3	2	15452 15453 15608	Containment Atmosphere Temperature	EQ, Seismic & QA	Generic Response III*
D.6.4	2	15452	Containment Sump Water Temperature	Alternate Instrumentation	SER 10/18/85 NRC Letter 6/1/87
D.7.1	2	1F-128	Makeup Flow - in	EQ, Seismic & QA	Generic Response III*
D.7.2	2	1F-134	Letdown Flow - out	EQ, Seismic & QA	Generic Response III*

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.7.3	2	1L-112 1L-141	Volume Control Tank Level	EQ, Seismic & QA	Generic Response III*
D.8.1	2	15327 15328	Component Cooling Water Temperature to ESF System	Seismic EQ - located in mild environment	Generic Response III*
D.8.2	2	23081 23082	Component Cooling Flow to ESF System	Seismic, EQ & QA	Generic Response III*
D.9.1	3	L-153 L-154 L-156	High Level Radioactive Liquid Tank Level	Monitoring performed locally	SER 10/18/85
D.9.2	3	P-1021 P-1036 P-1037 P-1038 P-1039 P-1048 P-1052 P-1053 P-1054 P-1055 P-1056 P-1057	Radioactive Gas Holdup Tank Pressure	Range, Monitoring performed locally	SER 10/18/85

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.10.1	2	MD-32214 MD-32215 MD-32216 MD-32217 MD-32218 MD-32219	Emergency Ventilation Damper Position - Shld Bldg Vent	EQ, Seismic & QA	Generic Response III*
	2	4640401 4640402 4640403 4640404 4640501 4640502 4640503 4640504	Emergency Ventilation Damper Position - Steam Exclusion	EQ, Seismic & QA	Generic Response III*
	2	MD-32236 MD-32237	Emergency Ventilation Damper Position - Aux Bldg Special	EQ, Seismic & QA	Generic Response III*
	2	CD-34142 CD-34143 CD-34144 CD-34145 CD-34146 CD-34147 CD-34176 CD-34177 CD-34178 CD-34179 CD-34180 CD-34181 CD-34182 CD-34183	Emergency Ventilation Damper Position - Control Rm Clean-Up	EQ, Seismic & QA	Generic Response III*

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #		VARIABLE	EXCEPTIONS	ACCEPTANCE
D.11.1	2	4191801 4191802 4191803 4192401 4192402 4192403		Status of Standby Power and other Energy Sources - Safeguards Bus Voltage	EQ - located in mild environment	Generic Response III*
	2	4190201 4190202 4190203 4190204 4190205 4190206	4190501 4190502 4190503 4190504 4190505 4190506	Emergency Diesel Generator Current and Voltage	EQ - located in mild environment	Generic Response III*
	2	21106		Instrument Air Header Pressure	EQ, Seismic & QA	Generic Response III*
E.1.1	1	1R-48 1R-49		Containment Area Radiation	No Exception	#
E.2.1	2	See C.3.5 R-1 R-3 1R-64 R-65 R-66		Radiation Exposure Rate	Power Supply, Control Room display, TSC readout, EQ, Seismic & QA	SER 10/18/85
E.3.1.1	2	1R-22 1R-50		Airborne Radioactive Materials, Noble Gases Containment or Purge Effluent	Range EQ - located in mild environment	SER 10/18/85 Generic Response III*
	2	23225 (EMA1)		Vent Flow Rate	Seismic & QA EQ - located in mild environment	# Generic Response III*

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
E.3.1.2	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Reactor Shield Building Annulus	See E.3.1.1	See E.3.1.1
E.3.1.3	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Auxiliary Building	See E.3.1.1	See E.3.1.1
E.3.1.4	2	1R-15	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Condenser Air Removal System Exhaust	Seismic EQ - located in mild environment Range - Uses R-22 & R-50 to meet range requirements	SER 10/18/85 Generic Response III *
E.3.1.5	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Common Plant Vent	See E.3.1.1	See E.3.1.1
E.3.1.6	2	See D.4.3	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Vent from Steam Generator Safety Relief or Atmospheric Dump Valves	See D.4.3	See D.4.3
E.3.1.7	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - All Other Sources	See E.3.1.1	See E.3.1.1

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
E.3.2.1	3	Sample	Airborne Radiohalogen and Particulates Sampling With On Site Analysis	Range	
E.4.1		Requirement Deleted	Radiation Exposure Meters	N/A	SER 10/18/85
E.4.2	3	See E.3.2.1	Airborne Radiohalogen and Particulates Sampling With On Site Analysis	See E.3.2.1	See E.3.2.1
E.4.3	3	Portable	Plant and Environs Radiation	No Exception	SER 10/18/85
E.4.4	3	Sample	Plant and Environs Radioactivity	No Exception	#
E.5.1	3	Z-863U Z-863L Z-873U Z-873L Z-882	Wind Direction	No Exception	#
E.5.2	3	S-862U S-862L S-872U S-872L S-881	Wind Speed	No Exception	#
E.5.3	3	T-861 U/L T-871 U/L	Estimation of Atmospheric Stability	No Exception	#
E.6.1	3	Sample	Accident Sampling - Primary Coolant and Sump	NSP Letter 12/3/82 Dissolved Oxygen	

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TABLE 7.10-1 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #1

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
E.6.2	3	Sample	Accident Sampling - Containment Air	No Exception	#

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*Letter, D M Musolf to Director NRR, "NUREG-0737, Supplement 1 - Generic Letter 82-33 Regulatory Guide 1.97 - Application to Emergency Response Facilities", September 15, 1983.

Since NSP committed to the full RG 1.97 Rev. 2 requirements for these items, the 10/18/85 SER stated that no further review by the NRC was required.

^ Design & Qualification Criteria Category (DQCC) for this variable as required by RG 1.97 Rev. 2 is identified, however, a more restrictive DQCC is identified in reference submittal #.

References 28-32, 51, 53, 59-62 and 64-73 were used to develop this table.

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
A.1	1	2P-709 (EMA2) 2P-710 (EMB2)	Reactor Coolant System Pressure	No Exception	SER 10/18/85
A.2	1	2L-920 (EMA2) 2L-921 (EMB2)	Refueling Water Storage Tank Level	No Exception	SER 10/18/85
A.3	1	2L-460 (EMB2) 2L-487 (EMA2) 2L-470 (EMA2) 2L-488 (EMB2)	Steam Generator Level	No Exception	SER 10/18/85
B.1.1	1	2N-51 2N-52	Neutron Flux	No Exception	#
B.1.2	3	Channel # Same as Rod #	Control Rod Position	No Exception	#
B.1.3	3	70850	Reactor Coolant System Soluble Boron Concentration	Range NSP Letter 12/3/82	SER 10/18/85
B.1.4	3^ See B.2.2	See B.2.2	Reactor Coolant System Cold Leg Temperature	See B.2.2	See B.2.2
B.2.1	1	2T-450A (EMA2) 2T-451A (EMB2)	Reactor Coolant System Hot Leg Temperature	Range	SER 10/18/85
B.2.2	1	2T-450B (EMA2) 2T-451B (EMB2)	Reactor Coolant System Cold Leg Temperature	Range	SER 10/18/85
B.2.3	1	See A.1	Reactor Coolant System Pressure	See A.1	See A.1

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
B.2.4	3^ See C.1.1	See C.1.1	Core Exit Temperature	See C.1.1	See C.1.1
B.2.5	1	2L-750 2L-752 2L-753 2L-760 2L-762 2L-763 2LM-750 2LM-760 2T-750 2T-760	Coolant Level in Reactor	No Exception	SER 5/8/86
B.2.6	2	2LM-750 2LM-760 2P-751 2P-761	Degrees of Subcooling	No Exception	SER 5/13/85 & SER 5/8/86
B.3.1	1	See A.1	Reactor Coolant System Pressure	See A.1	See A.1
B.3.2	2	2L-725 (EMA3) 2L-726 (EMB3)	Containment Sump Water Level	No Exception	#
		2L-727 (EMA3) 2L-728 (EMB3)	Containment Sump Wide Range Water Level	No Exception	#
B.3.3	1	2P-717 (EMA2) 2P-718 (EMB2)	Containment Pressure	No Exception	#

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #		VARIABLE	EXCEPTIONS	ACCEPTANCE
B.4.1	1	CV-31129 CV-31209 CV-31253 CV-31342 CV-31344 CV-31345 CV-31347 CV-31348 CV-31349 CV-31412 CV-31413 CV-31430 CV-31554 CV-31619 CV-31620 CV-31627 CV-31628 CV-31642 CV-31643 CV-31644 CV-31731	CV-31732 CV-31733 CV-31734 CV-31735 CV-31736 CV-31742 CV-31743 MV-32028 MV-32029 MV-32051 MV-32059 MV-32130 MV-32194 MV-32210 MV-32406 MV-32407 MV-32408 MV-32409 MV-32410 MV-32411	Containment Isolation Valve Position	Display by SPDS	
B.4.2	1	See B.3.3		Containment Pressure	See B.3.3	See B.3.3

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #		VARIABLE	EXCEPTIONS	ACCEPTANCE
C.1.1	1	13407 13408 13410 13411 13412 13413 13414 13415 13416 13418 13419 13420 13421 13422 13423 13424 13425 13426	13428 13429 13431 13432 13433 13434 13435 13436 13437 13438 13439 13440 13441 13442 13443 13444 13445	Core Exit Temperature	Replaced with qualified system consisting of 16 fully qualified CET readouts on the backup display (ICCM)	SER 5/8/86
C.1.2	1	By Sample		Radioactivity Concentration in Circulating Primary Coolant	Acceptable Alternate Instrumentation as defined by NSP letter dated 12/3/82.	SER 10/18/85
C.1.3	3	By Sample		Analysis of Primary Coolant (Gamma Spectrum)	No Exception	#
C.2.1	1	See A.1		Reactor Coolant System Pressure	See A.1	See A.1
C.2.2	1	See B.3.3		Containment Pressure	See B.3.3	See B.3.3
C.2.3	1	See B.3.2		Containment Sump Water Level	See B.3.2	See B.3.2

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
C.2.4	3^ See E.1.1	See E.1.1	Containment Area Radiation	See E.1.1	See E.1.1
C.2.5	3^ See E.3.1.4	See E.3.1.4	Effluent Radioactivity Noble Gas Effluent from Condenser Air Removal System Exhaust	See E.3.1.4	See E.3.1.4
C.3.1	1	See A.1	Reactor Coolant System Pressure	See A.1	See A.1
C.3.2	1	2X-719 (EMA3) 2X-721 (EMB3)	Containment Hydrogen Concentration	No Exception	SER 10/18/85
C.3.3	1	See B:3.3	Containment Pressure	See B.3.3	See B.3.3
C.3.4	2	2R-12 2R-22 2R-50	Containment Effluent Radioactivity - Noble Gas Effluent from Identified Release Points	Range EQ - located in mild environment	SER 10/18/85
C.3.5	2	2R-53 2R-59 2R-54 2R-60 2R-55 2R-61 2R-56 2R-62 2R-57 2R-63 2T-58	Radiation Exposure Rate - Inside Buildings or Areas in Direct Contact with Containment	Power Supply, Control Room Display, TSC readout, EQ, Seismic & QA	SER 10/18/85
C.3.6	2	2R-30 (Rack 21) 2R-37 (Rack 11) 2R-50 2R-22	Effluent Radioactivity - Noble Gases Inside Buildings or Areas in Direct Contact with Containment	Range EQ - located in mild environment Seismic -1R-50 only	SER 10/18/85 Generic Response III*
D.1.1	2	2F-626 (Process Rack 2SA) 2F-928 (Process Rack 2SD)	Residual Heat Removal System Flow	Seismic & QA	Generic Response III*

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.1.2	2	2T-627 (Process Rack 2SA)	Residual Heat Removal Heat Exchanger Outlet Temperature	Range, Seismic, EQ & QA	SER 10/18/85 Generic Response III*
D.2.1	3	2P-936 2P-937 2P-940 2P-941	Accumulator Tank Pressure	Non-safety	SER 4/27/93
	3	2L-934 2L-935 2L-938 2L-939	Accumulator Tank Level	Non-safety	SER 4/27/93
D.2.2	2	MV-32174 MV-32175	Accumulator Isolation Valve Position	EQ - locked open valves exempt from 10CFR50.49 QA - Status light, open indication only	
D.2.3	2	2F-110 2F-113	Boric Acid Charging Flow	Seismic, EQ & QA	Generic Response III*
D.2.4	2	2F-924 2F-925	Safety Injection Flow	No Exception	#
D.2.6	2^ See A.2	See A.2	Refueling Water Storage Tank Level	See A.2	See A.2
D.3.1	3	4955301 4955302 4955401 4955401	Reactor Coolant Pump Status	Use RCP Breaker status and KW Monitor instead of current indication	SER 10/18/85

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.3.2	2	2X-443 2X-444 2X-445 CV-31233 CV-31234	Primary System Safety Relief Valve Position and Flow	EQ, Seismic & QA	Generic Response III* Detectors are EQ.
D.3.3	1	2L-426 2L-427 2L-428	Pressurizer Level	Range	SER 10/18/85
D.3.4	2	2PZRHTRA/XD 2PZRHTRB/XD	Pressurizer Heater Status	QA, Seismic & EQ KW Monitor instead of current	SER 10/18/85 Generic Response III*
D.3.5	3	2L-442	Quench Tank (PRT) Level	No Exception	#
D.3.6	3	2T-439	Quench Tank (PRT) Temperature	Range	SER 10/18/85
D.3.7	3	2P-440	Quench Tank (PRT) Pressure	No Exception	#
D.4.1	1	See A.3	Steam Generator Level	See A.3	See A.3
D.4.2	2	2P-468 2P-469 2P-482 2P-478 2P-479 2P-483	Steam Generator Pressure	No Exception	#

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #		VARIABLE	EXCEPTIONS	ACCEPTANCE
D.4.3	2	2F-464 2F-465 2F-474 2F-475 2F-810 2F-811 2F-812 2F-813	2F-814 2F-815 2F-816 2F-817 2F-818 2F-819 2F-820	Main Steam Flow	No Exception	
	2	2Z-825 2Z-826 2Z-830	2Z-831 2Z-832 2Z-833	Safety/Relief Valve Positions	QA, Seismic & EQ	Generic Response III*
	2	2R-51 2R-52		Steam Line Radiation	QA, Seismic & EQ	Generic Response III*
D.4.4	3	2F-466 2F-467 2F-476 2F-477		Main Feedwater Flow	No Exception	#
D.5.1	2	23128 23129		Auxiliary Feedwater Flow	EQ, Seismic & QA	SER 10/18/85 Generic Response III*
D.5.2	1	2L-723 2L-724		Condensate Storage Tank Level	EQ - Located in mild environment	SER 10/18/85

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.6.1	2	MV-32108 MV-32109 MV-32110 MV-32111 MV-32114 MV-32116	Containment Spray System Valve Positions	Uses Alternate Instrumentation for Containment Spray Flow. See also A.2, D.1.2 and D.6.4	SER 10/18/85 NRC Letter 6/1/87
	2	24062	Caustic Addition Standpipe Level		
	2	4656001 4656002 4656101 4656102	Containment Spray Pump on/off Status		
D.6.2	2	15495 15496 15550 15551 15552 15553	Heat Removal by the Containment Fan Heat Removal System	QA, Seismic & EQ	Generic Response III*
D.6.3	2	15454 15455 15609	Containment Atmosphere Temperature	EQ, Seismic, & QA	Generic Response III*
D.6.4	2	15455	Containment Sump Water Temperature	Alternate Instrumentation	SER 10/18/85 NRC Letter 6/1/87
D.7.1	2	2F-128	Makeup Flow - in	EQ, Seismic & QA	Generic Response III*
D.7.2	2	2F-134	Letdown Flow - out	EQ, Seismic & QA	Generic Response III*

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.7.3	2	2L-112 2L-141	Volume Control Tank Level	EQ, Seismic & QA	Generic Response III*
D.8.1	2	15329 15330	Component Cooling Water Temperature to ESF System	Seismic EQ - located in mild environment	Generic Response III*
D.8.2	2	23090 23091	Component Cooling Water Flow to ESF System	Seismic, EQ & QA	Generic Response III*
D.9.1	3	See Table 7.10-1	High Level Radioactive Liquid Tank Level	Monitoring performed locally	SER 10/18/85
D.9.2	3	See Table 7.10-1	Radioactive Gas Holdup Tank Pressure	Range, Monitoring performed locally	SER 10/18/85
D.10.1	2	MD-32220 MD-32221 MD-32222 MD-22223 MD-32224 MD-32225	Emergency Ventilation Damper Position - Shld Bldg Vent	EQ, Seismic & QA	Generic Response III*
		See Table 7.10-1	Emergency Ventilation Damper Position - Steam Exclusion	EQ, Seismic & QA	Generic Response III*
		See Table 7.10-1	Emergency Ventilation Damper Position - Aux Bldg Special	EQ, Seismic & QA	Generic Response III*
		See Table 7.10-1	Emergency Ventilation Damper Position - Cont Rm Cleanup	EQ, Seismic & QA	Generic Response III*

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
D.11.1	2	4190401 4190402 4190403 4192301 4192302 4192303	Status of Standby Power and Other Energy Sources - Safeguards Bus Voltage	EQ - located in mild environment	Generic Response III*
	2	4190301 4190701 4190302 4190702 4190303 4190703 4190304 4190704 4190305 4190705 4190306 4190706	Emergency Diesel Generator Current and Voltage	EQ - located in mild environment	Generic Response III*
	2	21107	Instrument Air Header Pressure	EQ, Seismic & QA	Generic Response III*
E.1.1	1	2R-48 2R-49	Containment Area Radiation	No Exception	#
E.2.1	2	See C.3.5 2R-64 R-67 R-68 R-69	Radiation Exposure Rate	Power Supply, Control Room Display, TSC readout, EQ, Seismic & QA	SER 10/18/85
E.3.1.1	2	2R-22 2R-50	Airborne Radioactive Materials, Noble Gases Containment or Purge Effluent	Range EQ - located in mild environment	SER 10/18/85 Generic Response III*
	2	23226 (EMB2)	Vent Flow Rate	Seismic & QA EQ - located in mild environment	# Generic Response III*

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
E.3.1.2	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Reactor Shield Building Annulus	See E.3.1.1	See E.3.1.1
E.3.1.3	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Auxiliary Building	See E.3.1.1	See E.3.1.1
E.3.1.4	2	2R-15	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Condenser Air Removal System Exhaust	Seismic EQ - located in mild environment Range - Uses R-22 & R-50 to meet range requirements	SER 10/18/85 Generic Response III*
E.3.1.5	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Common Plant Vent	See E.3.1.1	See E.3.1.1
E.3.1.6	2	See D.4.3	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - Vent from Steam Generator Safety Relief or Atmospheric Dump Valves	See D.4.3	See D.4.3
E.3.1.7	2	See E.3.1.1	Airborne Radioactive Materials, Noble Gases and Vent Flow Rate - All Other Sources	See E.3.1.1	See E.3.1.1

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
E.3.2.1	3	Sample	Airborne Radiohalogen and Particulates Sampling With On Site Analysis	Range	
E.4.1		Requirements Deleted	Radiation Exposure Meters	N/A	SER 10/18/85
E.4.2	3	See E.3.2.1	Airborne Radiohalogen and Particulates Sampling With On Site Analysis	See E.3.2.1	See E.3.2.1
E.4.3	3	Portable	Plant and Environs Radiation	No Exception	SER 10/18/85
E.4.4	3	Sample	Plant and Environs Radiation	No Exception	#
E.5.1	3	See Table 7.10-1	Wind Direction	See Table 7.10-1	See Table 7.10-1
E.5.2	3	See Table 7.10-1	Wind Speed	See Table 7.10-1	See Table 7.10-1
E.5.3	3	See Table 7.10-1	Estimation of Atmospheric Stability	See Table 7.10-1	See Table 7.10-1
E.6.1	3	Sample	Accident Sampling - Primary Coolant and Sump	NSP Letter 12/3/82 Dissolved Oxygen	

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TABLE 7.10-2 REGULATORY GUIDE 1.97 REV. 2 VARIABLES - UNIT #2

SUBMITTAL #	DESIGN & QUAL. CRITERIA CAT.	CHANNEL #	VARIABLE	EXCEPTIONS	ACCEPTANCE
E.6.2	3	Sample	Accident Sampling - Containment Air	No Exception	#

*Letter, D M Musolf to Director NRR, "NUREG-0737, Supplement 1 - Generic Letter 82-33 Regulatory Guide 1.97 - Application to Emergency Response Facilities", September 15, 1983.

Since NSP committed to the full RG 1.97 Rev. 2 requirements for these items, the 10/18/85 SER stated that no further review by the NRC was required.

^ Design & Qualification Criteria Category (DQCC) for this variable as required by RG 1.97 Rev. 2 is identified, however, a more restrictive DQCC is identified in referenced submittal #.

References 28-32, 51, 53, 59-62 and 64-73 were used to develop this table.

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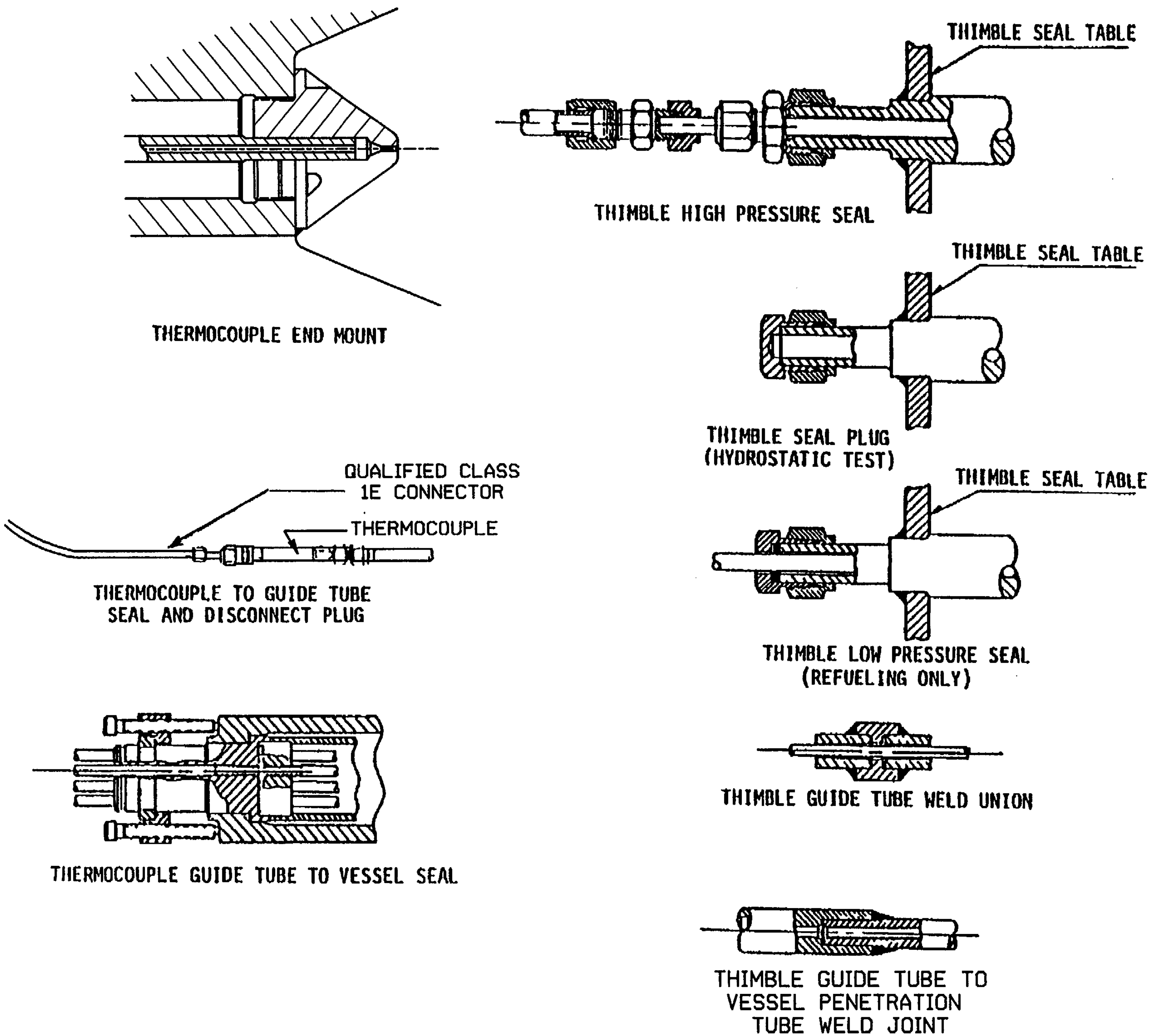


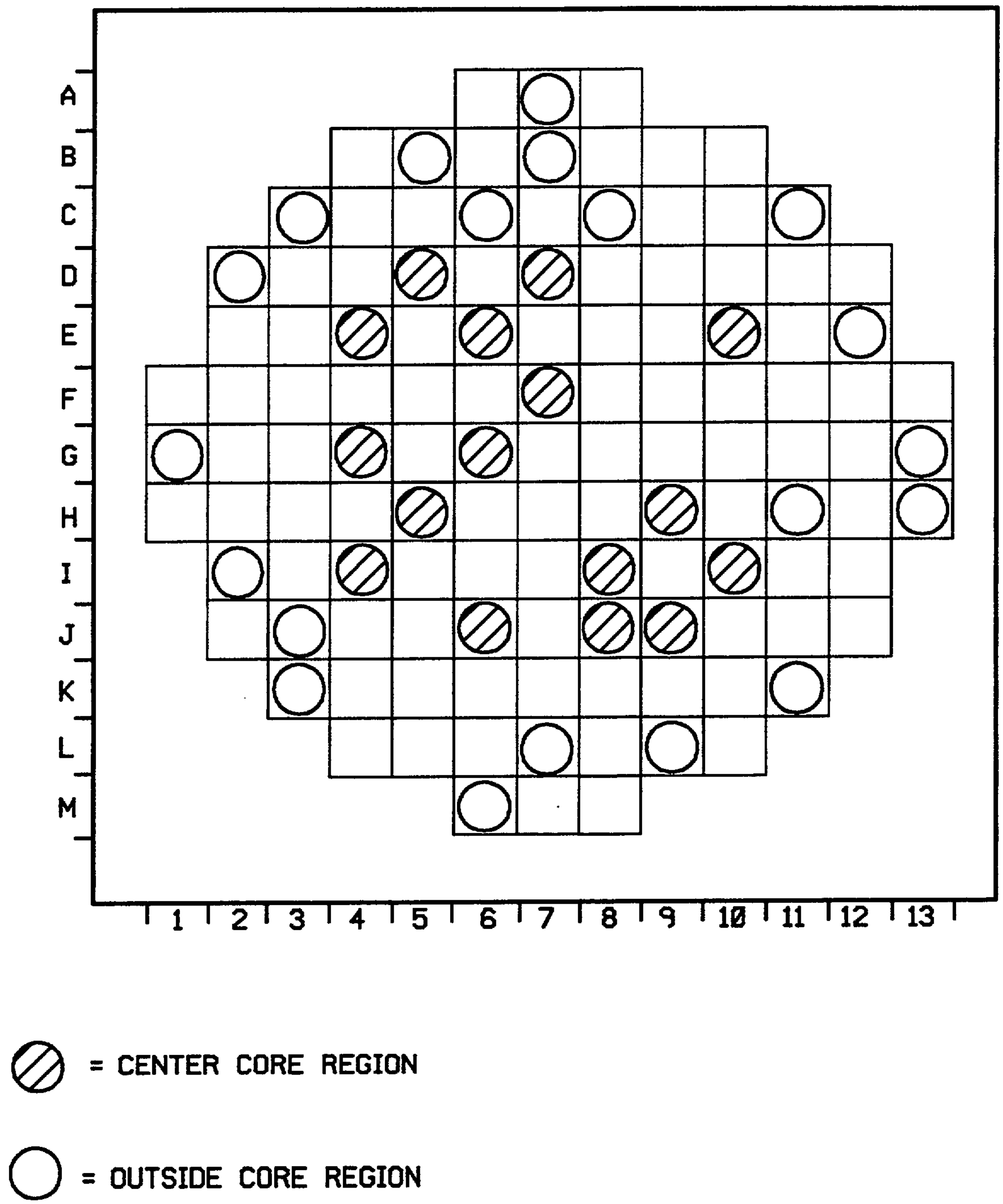
INCORE INSTRUMENTATION (DETAILS)

DWN T. MILLER	DATE 6-23-99
CHECKED	CAD FILE U0760LDGN

NORTHERN STATES POWER COMPANY
PRAIRIE ISLAND NUCLEAR GENERATING PLANT
RED WING MINNESOTA

SCALE: NONE

FIGURE 7.6-1 REV. 23



LOCATION OF INCORE THERMOCOUPLES

DWN T. MILLER	DATE 6-23-99	NORTHERN STATES POWER COMPANY PRAIRIE ISLAND NUCLEAR GENERATING PLANT RED WING MINNESOTA	SCALE: NONE
CHECKED	CAD FILE U07604.DGN		FIGURE 7.6-4 REV. 23

SECTION 8

PLANT ELECTRICAL SYSTEMS

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8.2 TRANSMISSION SYSTEM

8.2.1 Offsite Transmission Grid Configuration 01-014

The output of the Prairie Island Generating Plant is delivered to a 345/161 KV Substation located at the plant site. Electrical energy generated at 20 KV is transformed to 345 KV by the Generator Step Up Transformers. Figure 8.2-1 shows details of the Metropolitan 345 KV system. A one-line diagram of the 345 KV connections for Units No. 1 and 2 is shown in Figure 8.2-2.

There are five transmission lines that connect the Prairie Island Plant to the transmission system. Two of the 345 KV transmission lines are connected directly to the Red Rock 01-014
Substation and a third 345 KV transmission line is connected to the Blue Lake Substation. The Red Rock and Blue Lake Substations are connected to the Minneapolis, St Paul area high voltage grid. A fourth 345 KV transmission line is connected to the Byron Substation in southern Minnesota and from there, the line proceeds to the Adams Substation and then through Iowa to Missouri where it is tapped several times to major Substations.

The basic scheme used in the 345 KV portion of the Substation is the breaker-and-one-half system. 01-014

The 161 KV portion of the Substation is a single bus arrangement. The 161 KV Substation is connected to 345 KV Bus 2 by 345/161/13.8KV No. 10 Transformer. The fifth transmission line is a 161 KV line which connects to the Spring Creek Substation and then supplies power to the Red Wing, Minnesota area. 01-014

Figure 8.2-3 shows the site arrangement of transmission lines and underground power cables. A single line diagram for the Cooling Tower and Plant (345/161KV) Substation is included on Figure 8.2-2. The criteria for spacing between lines are based on national standards for such lines. 01-014

8.2.2 Offsite Grid Reliability

Reliability considerations to minimize the probability of power failure due to faults in the network interconnections and the associated switching are as follows: 01-014

a. Redundancy is designed into the network interconnections for the units by having four transmission circuits into the 345 KV system and one transmission circuit into the 161 KV system. These systems are interconnected at the site and any one 345 KV circuit is capable of providing the full power requirements for the startup or shutdown of either Unit. 01-014

b. Physical separation of transmission lines is maintained on site as much as possible to provide isolation. The transmission line spacing in the vicinity of the site is greater than the height of the towers. 01-014

c. Transmission line design for lightning performance is based on less than one outage per 100 miles per year.

d. The substation switching arrangement provides nine 345 KV circuit breakers for six transmission line/generator outlets. This type of design is referred to as a breaker-and-one-half design, and includes two full capacity main buses. Dual simultaneous relay protection is provided for each bus and line/outlet. Breaker failure relaying protects for scenarios where the interrupting device fails to clear a fault.

   Operating characteristics of this design include:

   1. any transmission line/outlet may be switched open under normal or fault conditions without interrupting another line/outlet.

   2. any single circuit breaker or bus may be isolated for maintenance without interrupting power or protection to any line/outlet.

   3. short circuits on a single main bus are isolated without interrupting service to any line/outlet.

   4. failure of a bus side breaker will result in the loss of only one line/outlet until the failed component is isolated.

   5. dual simultaneous relay protection provides coverage for failure of one set of protective relaying.

e. Design and construction of the 345 KV and 161 KV transmission lines exceed the requirements of the National Electrical Safety Code for heavy loading districts, Grade B construction.

With the above features, the probability of loss of more than one source of auxiliary power from credible faults is low, however, in the event of an occurrence causing loss of all the 345-KV and 161-KV connections, power for essential service is supplied from four onsite emergency diesel generators.

In the event that both Prairie Island Units trip simultaneously, the offsite supply to the safety features system would not be interrupted. The breaker-and-one-half design is such that the two unit trip event does not isolate auxiliary power supply points from the transmission lines serving the substation.

The adequacy of offsite power supply to the auxiliary safety sources in the event of a two unit trip is discussed below.

Voltage supplied to auxiliary systems from offsite sources after a two unit trip depends on many variables. The direction and magnitude of power flows due to system load, power transactions and pattern of on-line generation play a large role in post-trip voltage.

Studies using normal peak-load system steady state load-flow simulation show that loss of the maximum generation from Prairie Island (a 2-unit trip) can be sustained with adequate voltage. Offsite sources to auxiliary systems are not interrupted, and provide proper voltage to the safety equipment. 01-014

Key to this contingent performance ability are the spinning and standby reserves maintained by NSP and other MidContinent Area Power Pool (MAPP) member utilities. 01-014

These reserves total in excess of 15% of the MAPP peak load. (For example 1990 MAPP operating reserves totaled 3529 MW).

Contingent support immediately after loss of the Prairie Island Units is supplied by rotor inertia and governor action of other generating units throughout the interconnected eastern two-thirds of the United States and the eastern half of southern Canada. NSP derives this support over transmission tie-lines with capacity exceeding 3000 MW. After several minutes the MAPP spinning and standby reserve capability replaces the import from the interconnected systems. 01-014

No customer load interruption or break-up of NSP's transmission system is anticipated as a result of a Prairie Island two unit trip. The offsite supplies to the plant safety features therefore continue to operate without interruption. 01-014

Backup systems are in place to cover contingent system conditions which may exist prior to a two unit trip. An underfrequency load shed system is in use by all MAPP member utilities which would shed approximately 10% of the system load at each of three frequencies: 59.3 Hz, 59.0 Hz and 58.7 Hz. This shed of 30% of load is intended to restore a balance between load and generation and return system frequency to a proper level. 01-014

NSP has also installed a backup system to cover the multiple contingency events which could pose the threat of system voltage collapse. In the scenario of several prior contingencies, and a subsequent Prairie Island two unit trip, the adequacy of 345-KV offsite voltage source to plant auxiliary system is protected by automatic load shedding. This is intended to restore system voltage to a proper level. 01-014

Simulation of Prairie Island two unit trip event is performed using computer load flow models. NSP uses two types of load flow programs, one for modeled studies, and a second for analysis of real-time system conditions using telemetered voltage and power flow data. The computer models are representations of the transmission system electrical characteristics and components. Accuracy of the models are periodically verified by comparison with actual historical data. Further studies are performed to examine details of the dynamic conditions after the assumed loss of the Prairie Island Units. 01-014

8.2.3 <u>Protection and Control for Interconnections</u> 01-014

Each of the 161, 34.5 and 13.8 KV sources has both overcurrent and breaker failure protective relaying.

All 345, 161, 34.5 and 13.8 KV breakers are equipped with dual trip coils. 01-014

Each of the 345 and 161 KV feeders transmission line feeder breakers has primary, secondary and breaker failure protective relaying.

The DC control system in the substation consists of two completely independent 48 volt systems and two completely independent 125 volt systems. Each system has its own battery, charger and fused distribution cabinet. One 48 volt system is used for primary relaying requirements and the second 48 volt system is used for the secondary relaying requirements. One 125 volt system is used in closing of breakers and operation of trip coil #1. The second 125 volt system is used for the operation of trip coil #2. 01-014

Controls for 1H2 and 1H4 13.8 KV ACB's are in the Substation control house. DC control power for the cooling tower area 4.16 KV breakers is supplied by a single 48 volt battery located with the 4160 volt switchgear in the Cooling Tower Equipment House. 01-014

Under normal operating conditions the 13.8 KV breakers 1H2, 1H4 and 4160 volt breaker CT11-1, CT11-6, CT12-6 and CT12-7 are closed and the 4160 volt bus tie CT-BT 112 is open. The Auto/Manual Switch for Bus Tie breaker CT-BT 112 is normally maintained in the MANUAL position to prevent an automatic transfer that could potentially damage safety related equipment. Bus Tie breaker CT-BT 112 can be manually closed so that either cooling tower area transformer can supply both 4160 V bus sections. 01-014

A 345 KV bus #2 Lockout, No. 10 Transformer Lockout, operation of either the 13.8 KV feeder overcurrent or ground detection relaying, Lockout of CT 12 Transformer, or Lockout of 2RS Transformer (if 8H12 is closed) will trip and lockout 1H2 - 13.8 KV ACB and the 4160 volt source breaker CT12-7. 1H2 breaker failure relaying will also trip and lockout CT12-7. 00-262

With only CT11 Transformer feeding both 4.16 KV bus sections CT11 and CT12, breaker CT 12-7 is open and CT-BT 112 is closed. With a fault on bus section CT12, protective relays operate a lockout relay to trip and lockout breaker CT12-6, CT12-7 and CT-BT 112. 01-014

A phase or ground fault on 4160 volt feeder from CT12 Bus to Plant Safeguards bus 25 or 26 operates protective relays and trip 4.16 KV breaker CT12-6. 01-014

A 345 KV Bus #1 Lockout, CT1 Transformer Lockout, operation of either the 13.8 KV feeder overcurrent or ground detection relaying, Lockout of CT11 Transformer, or Lockout of 2RS Transformer (if 8H10 is closed) will trip and lockout 1H4 - 13.8 KV ACB and the 4160 volt source breaker CT11-1. 1H4 breaker failure relaying will also trip and lockout CT11-1. 00-262

With only CT12 Transformer feeding both 4.16 KV bus sections CT11 and CT12, breaker CT11-1 is open and CT-BT 112 is closed, a fault on bus section CT11, protective relays will operate a lockout relay to trip and lockout breakers CT11-1, CT11-6, and CT-BT 112. 01-014

With a phase or ground fault on the 4160 V feeder from CT11 Bus to Plant Safeguard bus 15 or 16, protective relays operate and trip breaker CT11-6.

The No. 1 and No. 2 Generator Step Up Transformers are each provided with an over-undervoltage relay to protect the transformer against grounds or an overvoltage condition occurring on the transformer while it is energized from the 345 KV Substation and delivering station auxiliary load. 01-014

8.2.4 <u>Onsite Interconnections</u> 01-014

Three separate power systems are provided by the Substation to the Plant 4160 volt safeguards buses. An overhead 161KV transmission line from the Substation to the Plant's 161/4.16KV 1R Transformer provides power to the Unit 1 4160 volt safeguards buses 15 and 16. An underground 35KV line from 345/35KV 2RS transformer in the substation to the Plant's 35/4.16KV 2RY Transformer provides power to the Unit 2 4160 volt safeguards buses 25 and 26. Two underground 13.8 KV feeders from the 345/13.8 KV Cooling Tower Transformer (CT1) and the tertiary of the 345/161/13.8 KV No. 10 Transformer provides the power to the Cooling Tower Substation 13.8/4.16 KV transformers CT11 and CT12.

These transformers supply separate buses in the Cooling Tower 4160 volt switchgear that may be connected together by a bus tie breaker. Underground feeders from Cooling Tower Bus CT11 feed Unit 1 safeguards buses 15 and 16. Underground feeders from Cooling Tower Bus CT12 feed Unit 2 safeguards buses 25 and 26.

1R Transformer, 2RS Transformer, CT1 Transformer and No. 10 Transformer can be supplied power from any of the four 345kV transmission lines.

The 13.8 KV tertiary of 345/161/13.8 KV No. 10 Transformer is the source to 1H2 13.8 KV Air Circuit Breaker (ACB) in the Substation. 1H2 13.8KV ACB is the source breaker for the underground feeder to the cooling tower area 13.8/4.16 KV CT12 Transformer. CT12 Transformer supplies 4.16 KV Bus Section CT12 through CT12-7, which is a 4.16 KV ACB in the Cooling Tower Equipment house. 4.16 KV Bus Section CT12 feeds the Unit 2 Safeguards 4.16 KV Bus 25 or 26 through 4.16 KV ACB's CT12-6 and 25-5 or 26-13, respectively.

345/13.8 KV CT1 Transformer is the source to 1H4 13.8 KV ACB in the Substation. 1H4 13.8 KV ACB is the source breaker for the underground feeder to the cooling tower area 13.8/4.16KV CT11 Transformer. CT11 Transformer supplies 4.16 KV Bus Section CT11 through CT11-1, which is a 4.16 KV ACB in the Cooling Tower Equipment house. 4.16 KV Bus section CT11 feeds Unit 1 Safeguards 4.16 KV Bus 15 or 16 through 4.16 KV ACB's CT 11-6 and 15-7 or 16-8, respectively.

8.2.4.1 Paths for Unit 1 Safeguards Trains 01-014

For Unit 1 there are four possible paths between the offsite transmission system and the safeguard 4160V buses. Each path is capable of providing the required power to shutdown the reactor and maintain it in a shutdown condition. These four paths are as follows: 01-014

- The first path is fed from the 161kv switchyard bus. This feeds the 1R transformer which in turn supplies power to buses 15 and 16. 01-014

- The second path is fed from the 345KV switchyard Bus 1. This feeds the 345/13.8KV Cooling Tower Transformer No. 1 which is connected via an underground cable run to the 13.8/4.16KV cooling tower transformer CT11. The secondary of this transformer feeds buses 15 and 16 through breakers CT11-1 and CT11-6. 01-014

- The third path is fed from the 345kv switchyard to transformer 2RS, transformer 2RY, breaker 2RYBT, breaker 12RYBT, breaker 1RYBT and then to buses 15 and 16. 01-014

- The fourth path is fed from the 13.8kv tertiary winding of the 345/161/13.8KV No. 10 Transformer. This 13.8kv feed supplies underground cable to 13.8/4.16KV cooling tower transformer CT12. From here is it fed through bus tie breaker CT-BT 112 to breaker CT11-6 and finally to buses 15 and 16. 01-014

8.2.4.2 Paths for Unit 2 Safeguards Trains 01-014

For Unit 2 there are four possible paths between the offsite transmission system and the safeguard 4160V buses. Each path is capable of providing the required power to shutdown the reactor and maintain it in a shutdown condition. These four paths are as follows: 01-014

- The first path is fed from the 345kv switchyard to transformer 2RS, breaker 2RSY, transformer 2RY and then to buses 25 and 26. 01-014

- The second path is fed from the 13.8kv tertiary winding of the 345/161/13.8KV No. 10 Transformer. This 13.8kv feed supplies underground cable to 13.8/4.16KV cooling tower transformer CT12. From here it is fed through breaker CT12-6 to buses 25 and 26. 01-0

- The third path is fed from the 161kv switchyard bus. This feeds the 1R transformer, breaker 1RYBT, breaker 12RYBT, breaker 2RYBT and then to buses 25 and 26. 01-014

- The fourth path is fed from the 345KV switchyard Bus 1. This feeds the 345/13.8KV Cooling Tower Transformer No. 1 which is connected via an underground cable run to the 13.8/4.16KV cooling tower transformer CT11. The secondary of this transformer feeds breaker CT-BT 112 to breaker CT12-6 and then to buses 25 and 26. 01-014

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8.4 PLANT STANDBY DIESEL GENERATOR SYSTEMS

8.4.1 Design Basis

The normal power sources for the safeguards buses are the 161-4.16/4.16 KV Reserve Auxiliary Transformer (Unit 1 1R), the 34.5/4.16 KV Reserve Auxiliary Transformer (Unit 2 2RY), and the redundant 13.8-4.16 KV Cooling Tower Substation buses (Unit 1 CT11 and Unit 2 CT12), as discussed in Section 8.2.1.

If the Reserve Auxiliary Transformers and the Cooling Tower Substation buses should fail, backup power is provided by two Emergency Diesel Generators in each unit sized and connected to serve the engineered safety features equipment of the unit. Each Emergency Diesel Generator is sized to start and carry the engineered safety features load required for the Design Basis Accident and concurrent loss of offsite power (LOOP). These loads are outlined in Table 8.4-1, and 8.4-2.

In the event that an Emergency Diesel Generator fails to start, only one set of redundant safety features components would be lost in that unit. By means of later manual switching, safety features components on the bus associated with a failed Emergency Diesel Generator could be fed from the other Unit's Emergency Diesel Generator up to the capacity of the running engine, as discussed under 8.4.4. There is no single known component whose failure prevents both Emergency Diesel Generators in a Unit from starting.

Emergency Diesel Generator starting control is independent of the AC system except for the associated 4.16 KV bus voltage-detecting relay which is connected in a "fail-safe" manner to start the Emergency Diesel Generator on loss of AC power.

Any two Emergency Diesel Generators are precluded from being paralleled during normal operation by administrative controls. During outages, Emergency Diesel Generators may be paralleled according to detailed manual procedures. For example (primarily during testing), both unit Emergency Diesel Generators can be manually synchronized (with synchronism check interlocks) to their associated energized 4160 volt safety features bus. Since the two buses involved might be fed at the time from the same offsite power supply, the two Emergency Diesel Generators would, in effect, be paralleled.

Unit 1 Emergency Diesel Generator equipment is located in separate heated rooms, protected from atmospheric conditions, in a Class I portion of the Turbine Building, permitting nearly ideal rapid-start conditions. The rooms are connected by a single access opening which is provided with a Class "A" fire rated door. The door, which is normally closed, is furnished with an extra-strong door closer equipped with a fusible link arm. Since the wall separating the two emergency diesel generators is parallel with the rotation of the diesel generator, it is incredible that a missile generated by the failure of one diesel generator will breach the wall opening.

Unit 2 Emergency Diesel Generator equipment is also located in separate rooms, protected from atmospheric conditions, in the Class I D5/D6 Building. These rooms are separated by a twelve inch thick reinforced concrete barrier. There are no wall openings directly between the two rooms.

One battery charger is in service on each battery so that the batteries always are at full charge in anticipation of loss of AC power incident. This ensures that adequate DC power is available for starting the generators and for other emergency uses.

8.4.2 Description

Each Emergency Diesel Generator, as a backup to the normal standby AC power supply, is capable of sequentially starting and supplying the power requirements of one of the redundant sets of engineered safety features for its reactor Unit. In addition, in the event of a station blackout (SBO) condition, each Emergency Diesel Generator is capable of sequentially starting and supplying the power requirements of the hot shutdown loads for its unit, as well as the essential loads of the blacked out unit, through the use of manual bus tie breakers interconnecting the 4160V buses as discussed in 8.4.4.

Unit 1 Emergency Diesel Generators (D1 and D2)

The Unit 1 Emergency Diesel Generators consist of two Fairbanks Morse units each rated at 2750 KW continuous (8750 hr basis), 0.8 power factor, 900 rpm, 4160 Volt, 3-phase, 60 Hertz. The 1,000 hour rating of each Emergency Diesel Generator is 3000 kilowatts. The 30 minute rating of each unit is 3250 kilowatts maximum. This figure is based on cooling water at a maximum temperature of 95°F and ambient air at a temperature of 90°F. The limitations imposed by the generator and the heat removal equipment limits the overall 30 minute rating of the system to 3250 kilowatts.

Each diesel engine is automatically started by compressed air stored at a pressure of approximately 250 psia. Two parallel solenoid admission valves deliver air simultaneously to a timed pilot air-distributor valve and an individual air-start valve located in each of the twelve cylinders. Starting air is thus admitted directly into the cylinder liners for fast, reliable cranking and starting. Adequate cranking effort is obtained with only six air valves. The additional six valves give increased starting reliability.

Each Unit 1 Emergency Diesel Generator has its own independent air starting system including a motor-driven air compressor, (powered from a 480 Volt emergency bus) and two accumulators each of sufficient capacity to crank the engine for 20 seconds. An interconnecting header with manual valving is provided between the starting system of the two engines, to allow the air accumulators of the opposite engine to be replenished. Cranking continues until the engine starts (speed over 250 rpm) or until a predetermined time limit (10-15 seconds) has elapsed, whichever occurs first. If an engine fails to start within the predetermined time limit, a "start failure" alarm is initiated and the engine control locks out, requiring manual reset.

Unit 2 Emergency Diesel Generators (D5 and D6)

The Unit 2 Emergency Diesel Generators consist of two tandem-drive units (gensets) manufactured by Societe Alsacienne de Constructions Mecaniques de Mulhouse (SACM), each rated at 5400 KW continuous (8750 hr basis), 0.8 power factor, 1200 rpm, 4160V, 3-phase, 60 Hertz. The gensets are radiator cooled independent of the plant cooling water system.

Each Unit 2 genset, has its own air starting system consisting of four independent subsystems, composed of a dryer, compressor, and air receiver. Any two of the four air receivers will start the genset within ten seconds. The receivers are sized to provide a minimum of five cranking cycles without recharging. The air compressors are powered from a 480 volt non-safeguards bus.

Cranking continues until the genset starts (based on lube oil pressure) or until five seconds has elapsed, whichever occurs first. If the genset fails to start within the five seconds, a "start failure" alarm is initiated and the genset control locks out, requiring manual reset.

The two air-start subsystems for each engine of the genset have interconnecting piping to the fuel injection stop jacks on the other engine. This piping is pressurized only on an overspeed trip by a valve device which opens at the overspeed setpoint. The piping to the opposite engine stop jack is to assure that both engines shutdown on an overspeed trip without depending on the governor shutdown solenoid valves. Each engine has two separate overspeed trip devices.

Units 1 and 2 Emergency Diesel Generators (D1, D2, D5, D6)

Control voltage for the diesel starting/control system is obtained from 125 volt DC System 11 for D1, and DC System 12 for D2. Similarly, control voltage is obtained from DC System 21 for D5, and DC System 22 for D6. Figures 8.5-1a, 8.5-1b, 8.5-2a and 8.5-2b show the 125V DC distribution for Unit 1 and Unit 2. For D1 and D2, loss of DC control power after the engine starts will not stop the engine or interfere with its operation. Direct current power must be restored to stop the engine electrically. For D5 and D6, engine speed control will fail to the hydraulic droop governor so that the speed/frequency depends on busload per the 2% droop curve. If only the control circuit for the genset control is lost, it will keep on running; however, if the entire DC source to the Vertical Panel for all circuits is lost, the diesel will keep running and cooling fans and fuel booster pumps will be lost. The operator would have to manually stop the genset.

To ensure rapid start, each diesel generator is equipped with electric heaters which furnish heat to the engine cooling water and engine lubricating oil when the engine is shut down. Motor driven circulating pumps for cooling water and lube oil operate continuously when the engines are shut down.

For each EDG, an audible and visual alarm system is mounted on the control panel located adjacent to the associated engine. An "engine trouble" alarm is sounded in the main control room whenever an alarm is sounded on the local engine generator control panel. A main control room alarm also sounds if the controls at the engine are not set on "automatic", or DC control power is lost.

Sufficient fuel is stored in the day tank for each Unit 1 Emergency Diesel Generator for up to two hours operation at full load, and for one hour of operation at full load for each Unit 2 Emergency Diesel Generator. Fuel from interconnected storage tanks can be transferred to the day tanks by electric pumps for operation of any single Emergency Diesel Generator up to two weeks. See Section 10.3.13 for further information.

Redundancy and flexibility are provided by two engineered safeguards buses, serving safety related equipment, associated with each of the two Units, connected so that each safeguards bus is served from a different Emergency Diesel Generator (four total). The sequence in which the safeguards loads are picked up by the Emergency Diesel Generators, and the delay times required, are discussed in the following loading description:

Each Emergency Diesel Generator is automatically started by either of the following events:

a. Undervoltage, which envelopes loss of voltage (including LOOP), or degraded voltage on the associated 4160 Volt buses (buses 15 and 16 for D1 and D2, and buses 25 and 26 for D5 and D6 respectively. Automatic starting of the Emergency Diesel Generators is initiated by a modified 2-out-of-4 voltage relay scheme on each 4160 Volt bus to which the Emergency Diesel Generator is to be connected.

b. Initiation of a Safety Injection Signal (both of the affected Unit's Emergency Diesel Generators start on this signal).

<u>Undervoltage Logic</u>

Relays are provided on buses 15, 16, 25 and 26 to detect undervoltage and degraded voltage conditions. The undervoltage setpoint is 75 $\pm$ 2.5% with a time delay of 4 $\pm$ 1.5 seconds. When an undervoltage condition exists on any of these buses, the associated PLC based Load Sequencer automatically initiates the following steps for the affected bus.

a. Trip source breakers to the bus.

b. Load rejection of designated loads on bus.

c. If the alternate offsite source is available, attempt to restore power from the alternate source.

d. If the alternate offsite source is not available, or does not successfully restore the bus, the associated Emergency Diesel Generator auto starts.

e. The EDG breaker closes onto the bus after the EDG has met established frequency and voltage criteria (within 10 seconds of receiving start signal).

f. Load restoration by sequenced steps at 5 second intervals.

If an SI signal is received during an undervoltage condition, the EDG is started and steps c and d above are not performed.

If an SI signal is present and the Emergency Diesel Generator is supplying power to the bus when an undervoltage occurs, its breaker is not tripped in item a. above. The bus remains powered from the Emergency Diesel Generator, and there is no load rejection or load restoration.

Degraded Voltage Logic

The degraded voltage setpoint is 95.5 $\pm$ 0.7% with time delays of 8 $\pm$ 0.5 seconds and 60 $\pm$ 3 seconds. The upper limit to the setpoint has been established to preclude unnecessary actuations of the voltage restoration scheme at the minimum expected grid voltage. Analysis has shown that the 8 second delay is adequate to account for normal transients, such as voltage dips from the starting of large loads, and is longer than the time required to start the Safety Injection pump at minimum voltage. This first delay annunciates that a degraded voltage condition exists. The second delay of 60 seconds allows the degraded condition to be corrected by external actions within a time period that will not cause damage to the operating equipment. With degraded voltage on any of the four safeguards 4160V buses, the associated PLC based Load Sequencer automatically initiates the following steps after the 60 second delay.

a. Auto start the Emergency Diesel Generator and trip the offsite source breakers to the bus.

b. Load rejection of the designated loads on the bus.

c. Close the breaker to the Emergency Diesel Generator once it has met established voltage and frequency criteria (within 10 seconds of receiving start signal).

d. Load restoration by sequencing loads at 5 second intervals.

If a SI signal is received during the 60 second degraded voltage time delay, the above logic is immediately actuated by the Load Sequencer with SI loads added during the last step, item d.

In both the undervoltage and degraded voltage scenarios described above, after voltage is re-established on the subject 4160 Volt bus, either from an offsite source or from an Emergency Diesel Generator, the Emergency Diesel Generator, if started (see discussion under 8.4.2), continues to run (loaded or unloaded) until manually shut down. The 480 Volt buses are immediately energized at the same time as the 4160 Volt bus from which it is fed.

Motors and loads which are operating or connected prior to the loss of voltage condition, that were not shed either automatically or manually during the time of voltage loss, and whose start signals are sealed-in would automatically restart or be re-energized upon return of bus voltage.

Motors not running prior to the loss of voltage condition would not start upon restoration of voltage, until subsequent manual or automatic action is initiated.

Load Sequencer Out of Service

With properly aligned 480V loads, the offsite sources have been analyzed to verify that a load sequencer failure will only affect the ability of the associated EDG to automatically power its respective safeguards loads following a LOOP independent of, or coincident with, a Design Basis Event.

Emergency Diesel Generator Loading

Three 25 HP Waste Gas Compressors are supplied, two fed from Emergency Diesel Generator D1 and one fed from Emergency Diesel Generator D2. In Emergency Diesel Generator D1 Loading Table 8.4-1, a waste gas compressor is included in the load listed for Unit No. 1 under Motor Control Center (MCC) 1L1 and is listed to start on Step 1 of the loading sequence.

Similarly, one waste gas compressor is supplied from Emergency Diesel Generator D2 at the same time.

Three air compressors (121, 122, 123) feed into a common Instrument Air header which, in turn, supplies Instrument Air for both Unit 1 and Unit 2. Compressor 121 is fed from Emergency Diesel Generator D1, via Unit 1 480 Volt Bus 111. Compressor 122 is fed via Unit 1 480 Volt Bus 121 from Emergency Diesel Generator D2. Compressor 123 is fed via Unit 2 480 Volt Bus 211 from Emergency Diesel Generator D5.

Instrument Air is not essential for plant safety during a DBA, however, for nonsafeguards reasons, it is desirable to maintain Instrument Air if possible under this condition, one compressor is adequate for both units. Assuming either Unit 1 Emergency Diesel Generator (D1 or D2) is operating, either Air Compressor 121 or 122 can be assumed to be operating. Similarly, if Emergency Diesel Generator D5 is operating, Air Compressor 123 can be assumed to be operating.

Safeguards MCC's and their associated motor operated valves are energized simultaneously with the 480V safeguards busses except for the pressurizer heaters MCC's which are energized on Step 6 of the Load Restoration Sequence.

Tables 8.4-1 and 8.4-2 show loading on Emergency Diesel Generators for a "worst case" condition as represented by a Safety Injection signal coincident with a complete loss of offsite power. A "small break" LOCA that was sufficient to initiate automatic Safety Injection (SI) action would represent the same inrush KVA load on the Emergency Diesel Generator as shown on the Tables cited. If the break is so small that automatic SI is not initiated, manual action would be required as soon as the operator is aware of the break. Manual action would represent loads less than or equal to that shown on the tables.

A small break would represent considerably less running load on the RHR Pump and possibly less on the SI Pump, but a longer running time for the SI Pump. As shown in Table 8.4-1, this would represent something less than 2414 KW shown as the maximum sequence load which is within the continuous rating of 2750 KW and 1000 hour rating of 3000 KW for each Unit 1 Emergency Diesel Generator. Similarly, as shown on Table 8.4-2, this would represent something less than 3609 KW shown as the maximum sequence load which is within the continuous rating of 5400 KW for each Unit 2 Emergency Diesel Generator. 01-020

Emergency Diesel Generator Design and Qualification

The redundant onsite standby power sources and their corresponding distribution systems are arranged in the Prairie Island plant to meet all the requirements of Safety Guide 6.

Emergency Diesel Generators D1 and D2 were sized per AEC Safety Guide 9, Paragraph C-2, which requires the predicted load seen by an EDG not to exceed the smaller of either the 2000 hour rating or 90% of the 30 minute rating. The D1/D2 2000 hour rating is unknown. The continuous rating, which bounds the 2000 hour rating conservatively, is 2750 KW. The D1/D2 30 minute rating is 3250 KW, and 90% of the 30 minute rating is 2925 KW. Therefore, the conservative limit of 2750 KW is placed on D1/D2 predicted loads.

As shown in Table 8.4-1, the maximum predicted sequence load during a LOCA and LOOP on D1 or D2 is 2414 KW and the maximum predicted steady state load during the same event is 2479 KW. As discussed in Section 8.4.4, the maximum predicted peak load for either D1 or D2 during a Unit 2 SBO event is 2624 KW. All of these predicted loads are less than the conservative limit of 2750 KW, therefore, D1 and D2 continue to meet the loading guidelines of paragraph C-2 of Safety Guide 9. Preoperational testing was performed on D1 and D2 in accordance with paragraph C-3 of Safety Guide 9. 01-074

With reference to Paragraph C-4 of Safety Guide 9, tests performed on a prototype of the Unit 1 Emergency Diesel Generator and subsequent calculations indicated that the speed limitations listed in Safety Guide 9 are met by Prairie Island Unit 1 Emergency Diesel Generators D1 and D2.

With reference to voltage variations, the prototype tests and subsequent calculations and surveillance testing indicate that the first inrush seen by the diesel when starting both the safety injection pump and the nonrejected loads that are connected to the EDG supplied bus can cause the voltage to decrease in excess of the 75% of nominal as stated in Safety Guide 9, and not be restored to normal within a maximum of 40% of the step duration (2 seconds). This voltage dip occurs on the first step of load application to the Emergency Diesel Generator and this exception to Safety Guide 9 does not degrade the reliability of the safety features in the plant for the following reasons:

1. Integrated SI testing history shows that < 3 seconds (60% of 5 seconds) is achieved. This is within the guidelines of Reg. Guide 1.9, Revision 2 utilized for D5/D6.

2. The Load Sequencer time interval is controlled by an internal digital clock in the Programmable Logic Controller driven Load Sequencer. This provides a very high degree of accuracy and repeatability in sequence timing. This lessens the needed margin between recovery from the dip and the end of the load step.

3. Historical data shows that the voltage returns to 100% well within five seconds as discussed below, assuring that excitation returns to normal, and full voltage is available for starting equipment at the beginning of the second load sequence step.

The anticipated loads on the Unit 1 Emergency Diesel Generators under accident conditions are outlined in Table 8.4-1. Engine speed under loading condition is difficult to predict accurately, but momentary speed drop during predicted inrush conditions will reach 90% with recovery in 2 to 4 seconds. Actual performance verification data is available from the Pre-Operational Surveillance Test results. Surveillance tests (SP1083) have shown 100% voltage recovery within three seconds.

The Unit 2 Emergency Diesel Generators (D5 and D6) meet the requirements of Reg. Guide 1.9, Revision 2, except portions of the 1984 Edition of IEEE 387 were implemented in the factory testing instead of the 1977 revision (NSP letter to NRC, September 9, 1989, Reference 5). These two diesel generators are rated at 5400 KW continuous. As Table 8.4-2 shows, the maximum predicted sequence load during a LOCA and LOOP on either Emergency Diesel Generator is 3609 kilowatts and the maximum predicted steady state load during the same event is 3477 kolowatts. Further, as discussed under 8.4.4, the maximum predicted load on D5 or D6 during a Unit 1 SBO is 3652 kilowatts. Thus the guidance of Reg Guide 1.9 paragraph C2 is satisfied. Testing has proven that the loading capabilities required by Reg Guide 1.9 paragraph C4 are also satisfied. 01-074 01-075

8.4.3 Performance Analysis: Loss-of-Coolant Accident and Loss of Offsite Power

Situations in which the high head safety injection pumps and the Emergency Diesel Generators would be simultaneously required are limited to the loss of either primary or secondary coolant from one Unit, concurrent with the loss of offsite a-c power. In the event of an accident requiring safety injection in one Unit, accompanied by loss of offsite power, the sequence of automatic operations is as follows:

a. A safety injection signal is derived from SI actuation circuits;

b. Reactor and turbine both trip;

c. When the reactor coolant pressure has fallen below 700 psi, the accumulators attached to the cold legs of loops A and B discharge their contents of borated water into the Reactor Coolant System;

d. The Emergency Diesel Generators start and upon loss of offsite power, as sensed by voltage relays, the load sequencers connect each Emergency Diesel Generator to its safeguards bus;

Upon receipt of a command signal, the Emergency Diesel Generators start. Within ten seconds, the EDG is up to speed and ready to accept load. As a result of continuing undervoltage on the buses, designated breakers then close, placing the EDG on the buses which feed the engineered safety features equipment (see discussion under 8.4.2). The load sequence on each Emergency Diesel Generator would be:

Step 1:	Safety Injection Pump and 480 V buses
Step 2:	Residual Heat Removal Pump Containment Spray Pump
Step 3:	121 Cooling Water Pump (Unit 2 only)
Step 4:	Component Cooling Water Pump 2 Fan Coil Units
Step 5:	Auxiliary Feedwater Pump (Unit 1 Train A, Unit 2 Train B) 1 Air Compressor (except Unit 2 Train B)
Step 6:	Pressurizer Heaters EDG Auxiliaries (Unit 2 only)
Step 7:	Control Room Chiller Chiller Water Pump

The time delay between starting the various components is long enough to allow the drive motors to approach synchronous speed (5 seconds or until voltage recovers, whichever is longer) as described in Section 8.4.2. The engines for the emergency diesel driven cooling water pumps are direct-connected to the pumps and operate independently of the Emergency Diesel Generators. Charging pumps are not necessary, and have not been included in the automatic starting sequence.

The configuration and operation of the Safety Injection System during the injection and recirculation phases of mitigation of a loss of coolant accident are described in Section 6.2.

In addition to the double ended break of a main reactor coolant pipe, all other less severe ruptures of the Reactor Coolant System require the operation of the engineered safety features system to an extent which depends upon the size of the rupture. Very small breaks cause expulsion of the reactor coolant at a rate which may be accommodated by operation of the charging pumps alone.

The double ended rupture of a main reactor coolant pipe remains the most severe of all of these accidents in terms of required operation of the engineered safety features system, and thus it is used together with a loss of auxiliary AC power as the basis for determining the requirements of the Emergency Diesel Generator capacity and, with a shutdown on the second unit, for determining the cooling water requirements, as described in Section 10.

8.4.4 Station Blackout

A Station Blackout (SBO) exists when there is a Loss of Offsite Power (LOOP) and concurrent loss of both of a unit's Emergency Diesel Generator sources. Prairie Island meets the SBO rule of 10CFR50.63 (June 21, 1988) and the related guidance of Reg. Guide 1.155 (August, 1988). An SBO is assumed to occur on only one Unit of a two unit site, in accordance with Reg. Guide 1.155. After either Emergency Diesel Generator in the non-SBO unit has completed load sequencing and has provided power to the designated safeguards equipment, the operator will manually close two series bus tie breakers to the SBO unit's associated safeguards bus. The involved bus tie breaker pairs are 15-8 and 25-17 (interconnecting buses 15 and 25), and 16-10 and 26-1 (interconnecting buses 16 and 26). These breakers are normally open during plant operation. Tests and analysis have shown that the non-SBO unit's Emergency Diesel Generator is available and the interconnecting bus ties can be closed within ten minutes of the realization that an SBO condition exists. Under assumptions used by Reg. Guide 1.155 and NUMARC-8700 for a plant of Prairie Island's configuration, AC electrical power will be restored to at least one safeguards bus on the SBO unit from offsite or from one of its own Emergency Diesel Generators within four hours of the onset of an SBO.

EGD Loading criteria:

Because of the low probability of either an SBO or DBA occurring, the simultaneous occurrence of a DBA and SBO is not credible. NUMARC 87-00 provides the loading criteria for an EDG in the non-SBO unit cross-tied to the SBO unit and requires the EDG to carry: (1) the loss of off-site power safe shutdown loads on the non-SBO unit, and (2) the SBO loads on the SBO unit for the required coping duration. Reference NUMARC 87-00 Appendix J Question and Answer B.3.

SBO Loads:

Typically during an SBO, once the power is available to the SBO unit through the bus ties, equivalent equipment would be operated in the SBO unit as under a LOOP. Notable exceptions are that the SBO unit's EDG auxiliaries would not be operated, nor would the 121 Cooling Water Pump for a Unit 2 SBO. This condition is more conservative for the SBO unit than operating the "essential" SBO equipment as required by NUMARC because it includes more load than the essential SBO load.

LOOP Loads:

The Hot Shutdown LOOP condition is chosen for the non-SBO unit because it is the worst case load condition for hot shutdown/hot standby forced cooling, cooldown or depressurization. Tables 8.4-3 and 8.4-4 provide listings of respective Unit 1 and Unit 2 equipment expected to operate during a LOOP for a unit in Hot Shutdown. These tables also provide the steady state KW loads for individual equipment and peak event loads.

Total Event Load:

The total event load for one EDG acting as the AAC source is the Hot Shutdown/LOOP load for its unit plus the SBO load from the other unit. Analysis has shown for these conditions the maximum predicted load during a Unit 2 SBO on either D1 or D2, is approximately 2624 KW. Similarly, for a Unit 1 SBO the maximum predicted load on D5 or D6 is approximately 3652 KW. Each of these is within the continuous rating of the respective unit's Emergency Diesel Generator.

8.4.5 Non-Safeguards Standby Diesel Generators

Non-safeguards 4.16 KV Buses 31, 41, 32 and 42 are normally supplied from Normal Buses 13, 23, 14 and 24 and their offsite sources, respectively. Buses 31 and 41 serve 480V Buses 310 and 410 respectively which have bus ties to form a double ended load center. Similarly, 480V Buses 320 and 420 are supplied by 4.16KV Buses 32 and 42. These 480V buses serve a variety of non-safeguards loads including plant process computers Uninterruptable Power Supplies, Non-safeguards station battery chargers, turbine generator AC auxiliaries, and miscellaneous Normal motor control center loads. The Bus 31/41 Load Centers are backed up by diesel generator D3, and Bus 32/42 Load Centers are backed up by diesel generator D4.

Diesel generators D3 and D4 consist of General Motors Electromotive Division units which were converted from MP-45 peaking units to emergency standby service. They are rated 2500 KW continuous (2750 KW peak), 0.8 power factor, 900 RPM, 4.16KV, 3-phase, 60Hz. They are radiator cooled with closed cooling,and utilize DC electric starting motors. DC power for engine starting, field flashing, and control is supplied from 125V DC Non-safeguards Systems 31 and 42. The diesel generators are capable of being manually run and synchronized onto the Normal 4.16KV plant buses from their respective control panels in the 31/41 and 32/42 Bus rooms. They are normally left in auto standby with the coolant and lube oil partially heated with a keep-warm system.

Both the 31/41 and 32/42 Load Centers have a load shedding and restoration scheme which will operate in the case that voltage is lost on a 480V bus. If both 480V buses in a load center lose power, then the diesel generator is given a fast start signal, source breakers are tripped, and the diesel comes up to speed and voltage after which the loads are sequenced back on the buses. Each diesel generator also has the capability to test the associated load-shedding and restoration scheme without actually tripping any loads.

8.5 DC POWER SUPPLY SYSTEMS

8.5.1 125 Volt DC System

The configurations of the DC Power Supply Systems for both Units are shown in Figures 8.5-1a, 1b, 2a, and 2b. Each Unit has two trains, with one battery and one battery charger serving each train. 125 VDC Systems 11 and 12 serve Unit 1 and 125 VDC Systems 21 and 22 serve Unit 2.

The battery charger is supplied from the associated safeguard 480 Volt system via a safeguard MCC. The battery chargers supply the normal DC loads as well as maintaining proper charges on the batteries.

The 125 VDC Systems supply power to plant controls, inverters serving noninterruptible AC Panels, and 125 VDC Systems 12 also supplies some emergency lighting.

Redundant safety controls, and nuclear instrument inverters are divided between the two DC trains associated with each Unit. Division of redundant safety controls is such that loss of one DC train does not defeat both sets of any redundant control circuits.

The station batteries and their supports are required for safety action, and are designed to operate under earthquake conditions consistent with plant seismic criteria.

8.5.2 Batteries and Battery Chargers

Each of the two station batteries per Unit has been sized to carry expected shutdown loads following a plant trip, and a loss of AC battery charging power for a period of 1 hour without battery terminal voltage falling below 105 volts. Major loads with their approximate operating times on each battery are listed in Tables 8.5-1 and 8.5-2, for Unit 1 and Unit 2 respectively.

Each of the four battery chargers has been sized to recharge its associated partially discharged battery within 24 hours, while carrying its normal load. A mobile emergency battery charger is provided in the event of outage of any of the four permanent chargers.

Each of the station batteries is located in a separate ventilated room in a Class I structure of the Turbine Building as depicted on Figure 1.1-10. Two access routes per room are provided for personnel safety. The access between adjoining battery rooms is through openings in the reinforced concrete block walls. Each of these openings is furnished with a counterweighted gravity sliding Class "A" fire door provided with dual fusible links, one located on each side of the common concrete block wall. Fire dampers are provided in the ventilation ducts. 01-088

Modification 91L310 "Control Room Monitoring of DC System", was implemented using Generic Letter 91-06, which outlines suggested parameters for DC monitoring, as a guideline.

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8.7 CABLES AND RACEWAYS

8.7.1 Cable Derating

Current ratings of all the cables used in this plant are based on the values specified for the type of cable used, by IPCEA, NEC, or by the individual cable manufacturer. Power cables are installed in ladder type cable trays. They are installed with only a single layer of cables per tray and clamped in the ladder to ensure that a specified spacing exists between these cables to ensure that air cooling is available. Alternatively, the manufacturer's cable derating based upon random fill is utilized, and the cable installation maintains spacing which provides margin from the assumed random fill.

Control cables are grouped in the trays with random lay, and the ampacity rating for these cables is based on the load of the control circuits involved. NEC derating factors are appropriately applied for multiple conductors in conduit, or multi-conductor cables in tray.

All original construction Power Control and Instrument Wire and Cable used on safeguards related circuits in the plant was purchased and qualification tested from manufacturers certifying that the insulation used on these conductors, including splicing material, would perform satisfactorily and not be appreciably degraded when exposed to the following environmental conditions:

Normal Temperature (40 years)	90°C (194°F) conductor temperature
Emergency Temperature (48 hours)	138°C (280°F)
Pressure	46 psig
Relative Humidity - Normal	70%
Relative Humidity - Emergency	100%
Radiation	5 x 10^7 Rads
Containment Spray	Dilute solution of Boric (Acid 2000 - 3000 ppm of Boron) adjusted to pH of 9.0 to 9.5 with Sodium Hydroxide 01-059
Fire	Successfully pass the so-called "Philadelphia Electric Flame Test" or its equal.

Cables, relays, and control devices supplied by P.S.&E were temperature qualified as follows: 01-059

a. Cable and wire - 280°F (138°C) - tested for a minimum of two hours at this figure.

b. Relays and control devices - 178°F (70°C).

All new cable installed after original construction is qualified for the environment it is used in.

8.7.2 Cable Routing

The following categories are those to which the term "Power Cable" shall apply:

4160 volt feeders
480 volt feeders
120/208 volt main feeders and motor feeders
125 volt DC main feeders and motor feeders
125 volt DC subfeeders that are rated 30 ampere or higher

The following categories are those to which the term "Control Cable" shall apply:

120 volt AC and 125 volt DC metering
120 volt AC and 125 volt DC relaying
120 volt AC and 125 volt DC interlocking, indication and controls
120 volt AC and 125 volt DC annunciation
125 volt DC subfeeders with a continuous rating of 25 amperes or less

The term "Instrumentation Cable" shall apply to all cables that are used for low level circuits. The following categories are some of the areas to which this will apply:

Computer input and output signals
Thermocouples
RTD's
Nuclear instrumentation and monitoring
Electronic control and recording devices
Transducer output signals

Mixing of power cables with control or instrument cables in the same tray is not permitted. Whenever a control and/or instrument cable tray and a power tray are in the same stack, the power tray is located in the top tier. Non-safeguard trays installed in stacks are spaced vertically with a minimum of 12" bottom to bottom in all areas. However, Class IE trays have a minimum bottom to bottom dimension between trays of 15" or 36", depending on adjacent groupings. Class IE trays containing instrument, control, or power cables have a minimum horizontal separation between redundant circuits of 36". Redundant circuits are not permitted in the same tray or conduit. If closer spacing than 36" cannot be avoided an approved barrier must be placed between the circuits. Cable trays are routed to avoid a fire hazard area, such as oil storage rooms, oil tanks, etc., whenever possible. When this cannot be done, the cable tray system is protected by fire resisting barriers. Whenever possible, a wall or floor has been introduced between trays carrying redundant safeguard circuits.

Class IE cables for each of the two units in the plant are divided into six(6) basic groups consisting of the four Reactor Protection/NIS (colored) Channels and "A" and "B" redundant trains. Minimum spacing between these groups are maintained as follows:

1.	Redundant A & B Trains	-36″ Horizontally (tray rail to tray rail) and Vertically (tray bottom to tray bottom)
2.	Reactor Protection/NIS Channels	-36″ Horizontally (tray rail to tray rail) and Vertically (tray bottom to tray bottom)
3.	Spacing Between any Reactor Protection/NIS Channel and any redundant A or B Train	-36″ Horizontally (tray rail to tray rail) and 15″ Vertically (tray bottom to tray bottom)

In items 1, 2, and 3, horizontal dimensions indicate clear air space between adjacent side rails. Vertical dimensions are tray bottom to tray bottom.

In item 3, redundant channels and trains are as follows:

> Train A and the White and Blue Instrument channels, are redundant to Train B and the Red and Yellow Instrument channels.

In item 3, minimum clear air spacing between bottom of upper tray and top of lower tray is 9″ which allows a maximum 6″ tray siderail for the 15″ vertical spacing. This minimum vertical spacing would also apply between a Class IE Tray and a Non-Safety System Tray.

Lack of separation between a single train and any one channel of Reactor Protection/NIS is allowed as long as the channel has the same power supply as the train. There must not be a lack of separation such that both trains, two channels, or one train and two channels are affected by an uncleared fault.

Where separation is not attainable, protective barriers are provided.

Barriers are required where mutually redundant trays cross. The barriers extend to each side of the protected tray by a distance equal to approximately three times the widest tray involved in either system. Barriers are provided in areas where non-safeguard trays may cause common mode involvement between two or more mutually redundant safeguard systems, and the mutually redundant trays are not separated by more than three times the sum of the widest trays involved in each interaction.

Cable and raceway separation and segregation within the D5/D6 Building and Fuel Oil Storage Area conform to the requirements of IEEE 384-1981 as modified by NRC Regulatory Guide 1.75. Deviations from the requirements contained in those documents are shown to be acceptable and meet the intent of IEEE 384/RG 1.75 through analysis. Cable and raceway interconnections between the D5/D6 Building and existing plant facilities, including direct buried cable, duct runs and other raceway systems, as well as all cables and raceways routed within existing plant facilities, are separated and segregated in accordance with the requirements contained in the balance of this section as a minimum.

Safety related Train B cables are routed from the D5/D6 Building to the plant's Class I corridor through the Turbine Building, a Class III structure. These cables are enclosed in a steel structure to afford them Class I protection. This enclosure is designed as a Class I structure and provides protection from seismic and jet impingement forces. Analysis addressed other concerns, such as cable derating (8.7.1), tornado winds, missiles and fires.

8.7.3 Cable Tray Sharing

Every effort has been made to install safety related cables in their own trays. However, there may be isolated cases where non-safety related cables may be installed in the same trays with safety related cables. Non-safety related cables are not routed with cables of one safety-related system and then routed through its mutually redundant system.

8.7.4 Fire Protection

Note: Fire Protection information is located in Plant Procedures F5, Appendices E, F, & K.

8.7.5 Cable and Cable Tray Markings

Each tray section of the cable tray system has an identifying code indicated on the drawings and the same identification is stenciled on the tray after it is installed. This stenciling is applied on each section of the tray whenever the code changes. Any tray that is continuous through walls or floors has the identifying code stenciled on both sides of the wall or floor. Cable trays assigned to safety related circuits are also color coded. This coding is accomplished by a strip of colored plastic tape 2″ wide by approximately 3″ long affixed to the tray near the stencilled identifying number. Conduits carrying safety related conductors are similarly color coded with a wrap of colored tape affixed to each end of the conduit and on either side of the wall or floor it passes through. Straight portions of the conduit have this tape affixed at suitable intervals. Each multi-conductor control or instrument cable has a 1″ diameter brass identifying tag at each end carrying the cable number, which is affixed on to the outer jacket of the cable.

Safety related control cables have a colored strip applied to the jacket approximately 1 foot long at intervals of approximately 10 feet.

Cable color coding consists of 6 colors, based primarily on 6 sources of electrical supply.

The first two supplies consist of Train "A" and Train "B". This may be 4160V AC, 480V AC, 240V AC, 120V AC or 125V DC. These AC supplies are fed directly from either offsite sources or Emergency Diesel Generators D1 and D2 for Unit 1, and from D5 and D6 for Unit 2. The DC Sources are fed from 125 VDC systems 11 and 12 for Unit 1, and from 125 VDC systems 21 and 22 for Unit 2.

The remaining 4 supplies consisting of 120V AC for instrument and reactor protection channels are fed from 4 separate inverters.

All cables associated with safeguards related equipment are color coded.

a. Train “A” supplies and controls are color coded “Orange”.

b. Train “B” supplies and controls are color coded “Green”.

c. Reactor protection and nuclear instrumentation systems (supply and control) listed as Channel I are color coded “Red”.

d. Reactor Protection and N.I.S. (supply and control) listed as Channel II are color coded “White”.

e. Reactor Protection and N.I.S. (supply and control) listed as Channel III are color coded “Blue”.

f. Reactor Protection and N.I.S. (supply and control) listed as Channel IV are color coded “Yellow”.

Power Supplies to the 4 inverters must originate from either Train “A” or Train “B”, White and Blue inverters are fed from Train “A” sources (either AC or DC) and Red and Yellow inverters are fed from Train “B” sources (either AC or DC).

If an engineered safeguards circuit is either Train A or Train B it can be easily distinguished from a reactor protection channel due to color coding.

If the circuit in question is an instrument channel entering a logic matrix with 2 or 3 other similar channels to form two safeguards action trains (“A” or “B”) by means of 2 out of 3, 2 out of 4, or similar logic means, that channel bears the same color code as the instrument bus (inverter) supplying it. AMSAC AFW actuation logic takes exception to this criteria, due to its required diversity of power.

Color coding is not intended to spell out the individual usage of each cable. The metal tag at the end of each cable carries a number distinctive to that one cable and by checking drawings this number can be used to find the exact usage of each cable.

Color coding was established as an easy means of maintaining the specified separation between 6 systems or sets of control, namely Train “A”, Train “B” and 4 instrument channels.

8.7.6 Relay Room Arrangement

The Safeguards Relay Racks and Reactor Protection Relay Racks are located in the Relay Room. The Safeguards and Reactor Protection Relay Racks are separated into “A” train and “B” train groups. Each train is in a common line-up with an approximate 5′-0″ aisle between groups.

The cable routing in this room is primarily in cable trays. The separation provided is in accordance with the previously stated separation criteria, except that one train is not allowed to interact with one channel even if the channel has the same power supply as the train.

8.7.7 Panel Wiring Separation

Control board switches and associated lights are furnished in modules. Modules provide a degree of physical protection for the switches associated lights and wiring.

The control board layout is based on making it easy for the operator to relate the control board devices to the physical plant and to determine at a glance the status of related equipment. This is referred to as providing a functional layout. Within the boundaries of a functional layout, modules are arranged in columns of control functions associated with separation trains defined for the Reactor Protection and Engineered Safeguards Systems. Teflon covered wire is generally used within the module and between the module and the first termination point.

The interface between the control board wiring and field wiring is made in terminal board cabinets one level below the control board. Teflon covered cables with connectors are provided for control board to terminal board cabinet interconnection. These cables are secured to metal supports to ensure separation of the cables consistent with the separation afforded by the front panel layout.

Redundant components are located in separate racks which are shown on Figure 7.8-1, which also shows the general arrangement of the control room.

Separation between redundant relay and terminal block cabinets is accomplished by using a separate cabinet for each train of components. Where redundant cabinets are placed side by side, the solid metal side walls of each cabinet provides the separation requisite.

Redundant Local Racks, Panels, and Control Stations used with Safeguards Systems are either separated by 3 feet of air space or an appropriate barrier is placed between the redundant components.

Instruments used with Safeguards Systems are either separated by a minimum air space of 36″ between mutually redundant devices or are mounted on independent racks separated by a minimum clear air space of 36″.

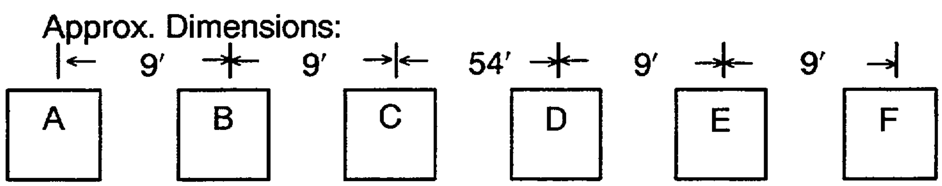
Cables entering redundant Local Racks, Control Stations Instrument Stations, Relay Cabinets, and Terminal Cabinets are designed to meet “Cable Separation” Criteria discussed in Section 8.7.2 “Cable Routing”.

Control Modules on the Control Boards in the Main Control Room, have a minimum center-to-center separation of 4-1/2″. Such controls are completely enclosed in a Fire Resistant housing. Cables are connected to these modules with plug-in metal connectors and the cables are insulated and jacketed with Teflon. The criteria for minimum separation between redundant cable is 4-1/2″ except in cases where redundant cables enter the same Control Module where center-to- center separation is 3-1/4″ and except for cases of reduced separation that have undergone technical evaluation (Reference 13).

Panels containing safety related components have redundant counterparts located in separate cabinets or isolated areas within cabinets. This includes such devices as 4160 V undervoltage transfer relays and automatic permissive starting sequence relays; emergency diesel generator protection and control relays; D.C. Distribution Panels; and Terminal Block Panels for redundant safety related wiring to main control board.

8.7.8 Electrical Penetrations

Electrical penetrations entering the Reactor Building are subdivided into 6 basic groups:



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Each of the six groups has provision for 12 penetrations. The configuration in each group is three wide by four high. Each penetration in each group is spaced 2′-0″ center to center from any penetration in its group.

Groups A, B and C are located in one quadrant of the containment vessel with groups D, E, and F located in another quadrant approximately 54′-0″ apart. 01-059

Each group of penetrations in each quadrant is separated by a distance of approximately 4′-0″ to any adjacent penetration in any other group.

Each penetration in a group has a specific circuit function, e.g., Nuclear Instrumentation, Instrumentation and Control, Low Voltage Power, and Medium Voltage Power. In addition, each group of penetrations is assigned an Engineered Safeguards Train and Reactor Protection Channels as follows:

Group A - Normal circuits

Group B - Normal and Channel II circuits

Group C - Normal, Train "A" and Channel III circuits

Group D - Normal, and Train "B" circuits

Group E - Normal, Train "B" and Channel I circuits

Group F - Normal, Train "B" and Channel IV circuits

Cables passing through the air annulus between the reactor building and the containment building are segregated into the six basic groups as shown above and the same relative spacing between the six groups is maintained, as the cables pass through this air annulus.

When control and instrumentation connections between cables within the containment and the penetration connections are made at terminal blocks, exposed connections are covered with environmentally qualified materials suitable for the LOCA environmental conditions. 01-059

8.7.9 Annulus Cable Supports

All electrical cables in the annulus are provided with support systems of various methods.

Generally, the cables are supported by tiers of cable trays that are supported by structural members bearing on the external support concrete and tied back to the shield building. Power cables are clamped to the cable tray system with enough slack allowed at both ends so as to accommodate differential movements between the two buildings without interaction. Control cables are not clamped to the cable tray system and slack has been allowed at both ends.

The large 5000 volt cables used for the reactor coolant pump are supported somewhat differently. A supporting framework is clamped to the penetration nozzle (part of the containment vessel) to provide a rigid support for the cables at the outboard end of the porcelain bushings. The cables have approximately 18" of slack prior to entering the embedded conduit in the shield building.

Annulus lighting system cables are all fully supported in conduit, which is fastened only to the shield building by clamps. 01-059

8.8 INSPECTION AND TESTING

Historic Background for Class I Electric Equipment:

Inspection and testing at vendor factories and/or during construction were conducted to demonstrate the following on all Class I electrical equipment:

a. All electrical assemblies operate within their design ratings;

b. All components are properly mounted;

c. All metering and protective devices are properly calibrated and function correctly;

d. All connections are properly made and the circuits are continuous. Operational testing of the normal and standby power systems were conducted under conditions which simulate the loss of offsite power conditions. This testing demonstrated the following:

   1. All essential loads can be operated in the proper sequence for each Design Basis Accident condition with normal power for essential loads available;

   2. The relaying and control system can detect a loss of external power and, with the buses dead, start and load the standby power sources;

   3. The standby power sources can provide sufficient power for an adequate time interval.

Historic Background for D1/D2 Qualification and Testing:

The essential requirements of generator sets for nuclear power plant protection include positive start, rapid acceleration and load acceptance with acceptable voltage drop and fast recovery to rated voltage. To obtain more information related to these requirements with the 3000 KW Unit 1 emergency diesel generator sets (D1 and D2), the following tests were conducted:

a. Start, Parallel and Load Acceptance

   Arrangements were made to isolate a block of power house engines and suitable resistive load from factory operations for these demonstrations.

   Automatic equipment was set up to synchronize the test generator set with the power house engines. The synchronizer signal simultaneously opens the power house engine breakers, and closes the test generator set breaker connecting 3000 KW resistive load.

b. Motor Starting

Motor starting tests included:

1. Across line starting 2000 HP motor
2. Across line starting 1250 HP motor
3. Across line starting 2000 HP and 1250 HP motors simultaneously
4. Across line starting 2000 HP and 1250 HP motors with 1000 KW initial resistive load.
5. Simultaneous start of 3000 KW generator set and 2000 HP motor
6. Simultaneous start of 3000 KW generator set and 1250 HP motor
7. Simultaneous start of 3000 KW generator set, 1250 HP motor and 2000 HP motor
8. Locked rotor tests of 2000 HP and 1250 HP motors.

Demonstrations of motor start capabilities were conducted with unloaded motors. However, it is believed that the data obtained permits accurate prediction of starting similar motors with specified loads.

c. Instantaneous Overload Capability

With the engine producing 3000 KW on a resistive load bank, an additional 1000 KW resistive load was added for 7-1/2 seconds duration. These demonstrations showed that the system would accept the additional load and recover to rated frequency and voltage during the overload condition. The purpose of this demonstration was to show capability of accepting overload surges which may occur when a large motor "locks in" during the starting cycle.

d. Reliability Test

Test information for the Prairie Island Unit 1 Emergency Diesel Generators consists of the information obtained from the prototype tests performed in the manufacturer's plant on September 13 and 14, 1968. The various tests performed are the same as those listed in b. above. The first test consists of cross-the-line starting of a 2,000 horsepower motor. Test figures indicated that at initial inrush the voltage dipped to a figure approximately 55% of normal. The locked rotor KVA of this 2,000 horsepower motor was approximately 11,000 KVA. The manufacturer's curves supplied with the Prairie Island generator indicates that for a starting KVA of 11,000 the voltage dip can be expected to reach 50% of rated. Calculations for the Prairie Island diesel generators indicate that the initial in-rush seen on either generator is approximately 6,800 KVA and is the worst condition.

Curves for the D1/D2 generators indicate that for an inrush of 6,800 KVA the initial voltage dip will be to approximately 62% of normal and will recover to 100% of normal within 1-1/2 seconds. The inrush KVA imposed on the factory engine during the prototype test was approximately 1-1/2 times that calculated for the Prairie Island engines. Because the prototype tests indicated that a larger load than anticipated at Prairie Island could be safely started and brought up to speed, and no difficulties were expected with the Prairie Island engines.

Another of the tests performed on the prototype consists of cross-the-line starting of both a 2,000 and a 1,250 horsepower motor. This represents an in-rush of approximately 18,000 KVA. Voltage dip at this point was approximately 40% of rated and full recovery to normal voltage was delayed until the in-rush reduced to approximately 8,000 or 9,000 KVA. The test indicated the motors could be started and accelerated to speed. Testing as indicated was more severe than anything that can be predicted for the Prairie Island units.

In addition to the performance requirements of a satisfactory nuclear power plant protection system, reliability is an extremely important aspect. To prove the generator set, arrangements were made to demonstrate its reliability.

The generator set was direct connected to a water rheostat. The system was adjusted to 3000 KW load and suitable controls attached to effect the following sequence:

1. Start unit and accelerate it to rated speed and load.
2. Maintain 3000 KW load for five minutes.
3. Stop generator set without an idling or cooling off period.
4. Allow to stand for 1 hour, 55 minutes permitting temperatures to drop to the keep warm level.
5. Repeat 1, 2, 3, and 4 above through 100 consecutive cycles.

The prototype unit started each time with no failures. Each start was accomplished in 10 seconds or less. At end of the test, the unit was disassembled for inspection and was found to be in excellent condition.

Based on these 100 successful starts the probability of success (reliability) in starting the Emergency diesel generator within 10 seconds after initiation of the Start Signal is calculated to be 0.977 at a 90% confidence level. See Figure 8.8-1.

The Confidence Level is the probability that the calculated reliability is no less than the actual reliability. In other words, an increase in confidence level will add conservatism to the calculated reliability. This is necessary since the failure data sample is small (no failures in 100 starts). Also, the Calculation ($r=e^{-\lambda t}$, λ=Failure Rate, t=Mission Period or Cycle, λt=Failures/Test) was based on the exponential distribution of failures. This was an acceptable assumption until sufficient failure data is obtained which proves that the failures fit a distribution other than the exponential distribution.

Additional failures per start data were accumulated during the weekly emergency diesel generator tests. Starting each of the two diesel generators once a week accumulated an additional 200 starts in 23 months. This added to the 100 prototype engine starts represents data accumulated on 300 starts.

The acceptance test consisted of a 100 hour run at full (3000 KW) load. Subsequent plant tests were run to establish that the total and incremental blocks of load could be adequately started and maintained.

These tests have established the reliability and capability of the emergency diesel generators to provide their design function.

The Auxiliary Electrical System is tested at regular intervals during the life of the plant to demonstrate the capability of the system to provide sufficient power to the essential loads.

Since the emergency diesel generators are utilized as standby units, readiness is of prime importance. Readiness can best be demonstrated by periodic testing which, insofar as practical, simulates actual emergency conditions. The testing program is designed to test the ability to start the system as well as to run it under load for a period of time long enough to bring all components of the system into equilibrium conditions, to assure that cooling and lubrication are adequate for extended periods of operation. Full functional tests of the automatic circuitry are conducted on a periodic basis to demonstrate proper operation.

If the number of tests were increased to possibly 300, it was felt that the calculated reliability could be raised to 99% based on an anticipated failure rate of two or three in 300 starts.

Northern States Power Company accumulated this additional failures per start data on D1/D2 during the initial preoperational and startup test phase of Prairie Island Unit #1 startup. This data when added to the 100 prototype engine starts represents data accumulated on 300 starts.

The Unit 1 emergency diesel generator preoperational testing program included tests that:

1. Verified that the diesel generator's control, power and auxiliary systems can be normally maintained at a ready operating condition.

2. Verified that the various control switches in the diesel generator rooms activate the engine stopping relay.

3. Verified that the diesel operators can be started and controlled from the diesel generator rooms.

4. Verified that the diesel generators can be started and controlled manually from the control room G-1 panel.

5. Verified that the diesel generators automatically trip from the various engine trip signals and the alarms do occur, but does not trip from these signals if the MCA relay is closed.

6. Verified that the diesel generators can be paralleled with the NSP interconnected system and operated at various loads for a two week period. This test also included fuel consumption tests.

7. Verified that the diesel generators can carry a load of 3250 kilowatts for 30 minutes.

8. Verified that the diesel generators start when initiated by the undervoltage relay scheme on each 4160 volt bus to which the diesel generator is connected.

9. Verified that the diesel generator performance upon loss of the largest single load during emergency operation, does not adversely affect either of the diesel generators. These tests involved loading the diesel generators as outlined in Table 8.4-1 of FSAR Amendment 19, tripping of the largest single load, and measuring the voltage and frequency disturbance. This test also verified the proper loading sequence and include pumping of water to the vessel with the RHR pumps and the safety injection pumps.

The above tests were part of the Preoperational (Preop) Test Program for D1/D2 and the results are available in the Prairie Island Plant Preop Test File. All subsequent starting and testing is documented and becomes part of the plant surveillance file.

<u>Historic Background for D5/D6 Qualification and Testing:</u>

The Unit 2 Emergency Diesel Generators (D5/D6) underwent the following factory tests conducted by the manufacturer, SACM. This testing fulfilled the requirements for qualification testing delineated in Reg Guide 1.9, December 1979, and IEEE-387 with two principle exceptions, discussed in NSP's letter of September 29, 1989 (Reference 5) to the NRC, and accepted by their letter of January 31, 1990 (Reference 7). The first exception is utilizing portions of the 1984 edition of IEEE-387 instead of the 1977 edition invoked by Reg Guide 1.9. The second was 70 start and load acceptance tests, (item b. below) in place of the prescribed 300. The basis of this lesser number of start tests is summarized in item d. below.

a. Load Capability Test

The genset was started and run until system temperatures were at equilibrium. The generator set was then loaded to 110% of nameplate load for a continuous period of two hours. The generator set was then loaded to 100% of nameplate load (5400KW) for a continuous period of twenty two hours. Finally, the generator set was tested for loss of load transient response, which verified that engine overspeed values remained within acceptable parameters.

b. Start and Load Acceptance Test

The genset was started thirty times at standby temperatures and five times at normal operating temperatures. The diesel generator set was required to start and reach operating speed within ten seconds for this test and was step loaded to 50% of the continuous rating.

Each diesel generator set was subjected to one simulated loading sequence, using appropriate combinations of motor and resistive loads. Motors with horsepower ratings of 250, 750, and 1000 HP were used in combination to closely match the values for each sequence step load. Loading was continued until the 5400 KW generator load rating was reached. The generator set then underwent a loss of 100% load test with voltage and frequency monitored during the transient.

c. Margin Test

The diesel generator set underwent two margin tests, each consisting of start, acceleration, and step loading to a value at least 10% larger than the largest step load. A step loss of this load was then initiated, with voltage and frequency monitored during the transient.

d. Reliability Test

For the type of diesel generator set utilized for Prairie Island Unit 2, SACM applied extensive qualification testing for other nuclear sites. The results of this type testing included:

(1) over 600 successful test cycles (start and load) without a failure,

(2) over 1500 successful starts without a failure, and

(3) over 100 starts with various subsequent loading profiles successfully applied.

This extensive testing, in conjunction with the factory testing described above, demonstrated the ability of the diesel generator sets to reliably start and carry load under required conditions. The high operational reliability of these generator sets and low failure rate (1.25 x 10 -3/hour) support the qualification of this design for emergency use at Prairie Island.

Site testing implemented the guidance of Reg Guide 1.108, August 1977, as outlined in NSP's letter of September 29, 1989 (Reference 5), including repeat of the factory 24-hour load run. The Unit 2 diesel generator preoperational testing program included tests that:

1. Demonstrated proper startup operation by simulating loss of all AC voltage and demonstrating that the diesel generator set could start automatically and attain the required voltage and frequency within acceptable limits.

2. Demonstrated proper operation under design accident loading sequence with voltage and frequency maintained within acceptable limits.

3. Demonstrated full load carrying capability for 24 hours of which 22 hours was at a load equivalent to the continuous (100% nameplate) rating of the diesel generator, and two hours was at a load equivalent to 110% of nameplate rating. This test, in conjunction with others, also verified proper operation of the cooling system.

4. Demonstrated proper operation during load shedding, including loss of the largest single load, and a complete loss of load, without exceeding voltage transient requirements and overspeed limits.

5. Demonstrated functional capability at full load temperature conditions by rerunning test one and two immediately following test three above.

6. Demonstrated the ability to synchronize with offsite power while connected to the emergency load, transfer this load to offsite power, isolate and return the diesel generator to standby status.

7. Demonstrated proper performance while switching from one fuel oil supply to another.

8. Demonstrated the capability to supply emergency power within required time was not impaired during periodic testing.

9. Demonstrated required reliability by performing 35 consecutive starts for each generator set.

10. Demonstrated proper functioning of the load sequencers under simulated emergency conditions to trip load breakers, start the diesel generators, select proper source for the emergency bus, and sequentially load the bus.

A loss of power memory test was also performed on the programmable logic controller (PLC) to verify proper resumption of operation upon restoration of power to the PLC.

11. Verified air start cranking capacity to crank the diesel engine at least five times without recharging the air receiver.

The above tests and results are maintained in the Prairie Island plant files.

Periodic testing and surveillance of the diesel generators are performed in accordance with the requirements contained in the Technical Specifications. The tests specified for the diesel generators will demonstrate their operability and continued capability to start and to carry rated load. Each Emergency Diesel Generator is required to meet a target reliability of 97.5% as determined by NUMARC 87-00, Appendix D, Rev. 1. 01-025

The station batteries and other equipment associated with the battery systems are easily accessible for inspection and testing. Service and testing is performed on a routine basis in accordance with recommendations of the manufacturers. Typical inspections included visual inspections for leaks and corrosion, and checking all batteries for voltage, specific gravity, and electrolyte level. At the time of installation, a full load discharge test was made to prove that battery capacity is adequate for the Design Basis Accident.

8.9 ENVIRONMENTAL QUALIFICATION OF SAFETY-RELATED ELECTRICAL EQUIPMENT

The Equipment Qualification Branch of the Office of Nuclear Reactor Regulation, Nuclear Regulatory Commission (NRC), has required all licensees of operating reactors to submit a re-evaluation of the qualification of safety related electrical equipment which may be exposed to a harsh environment. This requirement was implemented primarily by the issuance, on January 14, 1980, of IE Bulletin No. 79-01B (Reference 8) with subsequent clarifying supplements in February, September, and October, 1980.

The Bulletin required that a master list of safety related systems and equipment be generated, all accident service conditions be defined, and the equipment be evaluated in accordance with guidelines in the bulletin.

Northern States Power Company has provided responses to the Bulletin in March, May, July and October 1980. The October 31, 1980 (Reference 9) submittal represented the final response to IE Bulletin No. 79-01B. This response included revised system component evaluation worksheets and provided a complete and current "Master List".

On May 22, 1981, the NRC issued the Prairie Island Nuclear Generating Plant Safety Evaluation Report (SER) (Reference 10) which summarized their assessment of the March, May, July and October 1980 submittals. A response to IE Bulletin No. 79-01B SER was submitted to the NRC in a letter dated August 26, 1981 (Reference 11). This submittal includes a detailed response to the NRC evaluation and provides documentation of the Equipment Qualification Program that is being undertaken by Northern States Power Company. The program ensures that all safety related equipment is capable of performing its safety related function during postulated accident conditions.

A follow-up submittal was made to the NRC on April 30, 1982 (Reference 12). This submittal included a revised Master List and Component Evaluation sheets reflecting updated qualification information and newly identified components, qualification information for TMI Action Plan equipment and a list of outstanding items and schedule for completion. On August 27, 1982, information regarding pressure and temperature profiles outside containment in relation to the environmental qualification review was submitted in response to an NRC request (Reference 14).

On April 25, 1983, the NRC issued a Safety Evaluation for environmental qualification of safety-related electrical equipment which summarized their assessment of the August 26, 1981, February 1, April 21, and April 30, 1982 submittals (Reference 15). A response to this SER dated Nov. 23, 1983 summarized the status of deficiencies noted in the April 25, 1983 safety evaluation.

On January 21, 1983 the NRC published in the Federal Register the final rule on environmental qualification of electric equipment important to safety for nuclear power plants. The rule became effective on February 22, 1983. This rule superseded all previous NRC requirements for environmental qualification of electrical equipment.

This rule, Section 50.49 of 10 CFR 50, specifies the requirements for environmental qualification of electrical equipment important to safety located in a harsh environment. In accordance with this rule, equipment for Prairie Island may be qualified to the criteria specified in either the DOR guidelines or NUREG- 0588, except for replacement equipment. Replacement equipment installed subsequent to February 22, 1983 must be qualified in accordance with the guidance of Regulatory Guide 1.89, unless there are sound reasons to the contrary.

A meeting was held with the NRC on December 1, 1983 to discuss all remaining open issues regarding environmental qualification, including acceptability of the environmental conditions for equipment qualification purposes. Discussions also included general methodology for compliance with 10 CFR 50.49, and justification for continued operation for those equipment items for which environmental qualification was not yet completed. The minutes of the meeting and proposed method of resolution for each of the environmental qualification deficiencies are documented in Reference 16.

The proposed resolutions for the equipment environmental qualification deficiencies, identified in earlier correspondence are described in Reference 15. During the December 1, 1983 meeting, the staff discussed the proposed resolution of each deficiency for each equipment item and found the NSP approach for resolving the identified environmental qualification deficiencies acceptable. The majority of deficiencies identified were documentation, similarity, aging, qualified life and replacement schedule. All open items identified in the SER dated April 25, 1983 (Reference 15) were also discussed and the resolution of these items were found acceptable by the NRC Staff.

Compartment temperature and pressure profiles for steamline ruptures have been recalculated to take into account heat transfer to the steam from the uncovered portion of the generation tubes as required by NRC Information Notice 84-90. WCAP 10961-P (Reference 17) used the revised heat transfer methodology of IN 84-90 to compute new mass and energy releases. This was then used to calculate revised environmental conditions for the auxiliary building. Current environmental condition profiles are maintained by the PINGP EQ Program. 01-012

Three categories of electrical equipment were identified in 10 CFR 50.49 as requiring environmental qualification. Equipment described in paragraph (b)(1) of 10 CFR 50.49 has been identified through a review of the accident analyses provided in the FSAR, a review of the emergency procedures, a review of safety system flow diagrams and Q-List, and a review of the installed equipment locations with respect to postulated harsh environmental zones. Our current master equipment list includes all equipment within the scope of paragraph (b)(1) of 10 CFR 50.49.

Equipment identified in paragraph (b)(2) of 10 CFR 50.49 is non-safety-related electrical equipment whose failure could prevent accomplishment of safety functions of equipment identified in paragraph (b)(1) of 10 CFR 50.49.

This equipment was principally identified through system review criteria and identification of display instrumentation referenced in the LOCA and HELB emergency procedures. The methodology used is summarized below:

- The wiring diagrams of safety related electrical equipment as defined in paragraph (b)(1) of 10 CFR 50.49 were reviewed to identify any auxiliary devices, electrically connected directly into the control or power circuitry, whose failure due to postulated environmental conditions could prevent the required operation of the safety-related equipment.

- The review discussed above addressed the potential failure of safety-related electrical equipment after its qualified operating time but before the end of the postulated accident.

Post-accident monitoring equipment has been identified in accordance with paragraph (b)(3). In addition, our response to NUREG-0737, Supplement 1 - Generic Letter 82-33 was transmitted to the NRC on September 15, 1983. This letter identified the qualification requirements and implementation schedule for Regulatory Guide 1.97 equipment. This equipment was qualified and added to the master equipment list in accordance with the schedule provided in the September 15, 1983 letter. 01-012

The master equipment list contains the necessary equipment to mitigate the consequences of all Design Basis Accidents (DBAs) identified in the FSAR, including flooding in the auxiliary building.

Equipment qualification is an on-going process that requires implementation into the activities of plant operation. The master equipment list (EQML) will change over the course of plant life due to system design changes, replacement equipment, or additional (b)(1), (b)(2), and (b)(3) equipment identified through procedural changes, licensing changes, etc. The PINGP EQ Program was developed to establish and maintain the regulatory requirements for the environmental qualification of electrical equipment. The program provides for such activities as the identification of electrical equipment within the program, the environmental specifications by plant location, providing auditable documentation supporting the equipment's environmental qualification, and ensuring appropriate reviews affecting environmentally qualified equipment are performed as required.

Equipment in the D5/D6 Building, a "mild" environment, is not subject to the requirements of 10CFR50.49.

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TABLE 8.4-1 EMERGENCY DIESEL GENERATOR LOADING DURING UNIT 1 LOCA/DBA COINCIDENT WITH LOOP[1] UNIT 1 (TRAIN B)

LOAD SEQUENCE	ADDED LOAD[2]
0 SECONDS (STEP 1)	1084 KW
5 SECONDS (STEP 2)	377 KW
10 SECONDS (STEP 3)	0 KW
15 SECONDS (STEP 4)	253 KW
20 SECONDS (STEP 5)	329 KW
25 SECONDS (STEP 6)	202 KW
30 SECONDS (STEP 7)	169 KW
TOTAL	2414 KW

97004-04

LOAD PERIODS	TOTAL LOAD[3]
0 - 5 MINUTES	2479 KW
5 - 30 MINUTES	2407 KW
30 MINUTES - 1 HOUR	2405 KW
1 HOUR - 14 DAYS	1523 KW

97004-04

1 Train B provides highest anticipated event loads for Unit 1 with data known as of March 21, 1994 as provided on the Prairie Island Motor List; will be updated if significant changes occur.

2 Loads added per each sequence step, taken from Calculation ENG-EE-018.

3 Peak total in each time period, taken from Calculation ENG-EE-021.

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TABLE 8.4-2 EMERGENCY DIESEL GENERATOR LOADING DURING UNIT 2 LOCA/DBA COINCIDENT WITH LOOP[4] UNIT 2 (TRAIN A)

LOAD SEQUENCE	ADDED LOAD[5]
0 SECONDS (STEP 1)	1180 KW
5 SECONDS (STEP 2)	413 KW
10 SECONDS (STEP 3)	807 KW
15 SECONDS (STEP 4)	249 KW
20 SECONDS (STEP 5)	326 KW
25 SECONDS (STEP 6)	465 KW
30 SECONDS (STEP 7)	169 KW
TOTAL	3609 KW

01-020

01-020

LOAD PERIODS	TOTAL LOAD[6]
0 - 5 MINUTES	3477 KW
5 - 30 MINUTES	3448 KW
30 MINUTES - 1 HOUR	3452 KW
1 HOUR - 14 DAYS	2580 KW

4 Train A provides the highest anticipated loads for Unit 2 with data known as of March 21, 1994 as provided on the Prairie Island Motor List; will be updated if significant changes occur.

5 Loads added per each sequence step, taken from Calculation ENG-EE-018.

6 Peak total in each time period, taken from Calculation ENG-EE-021.

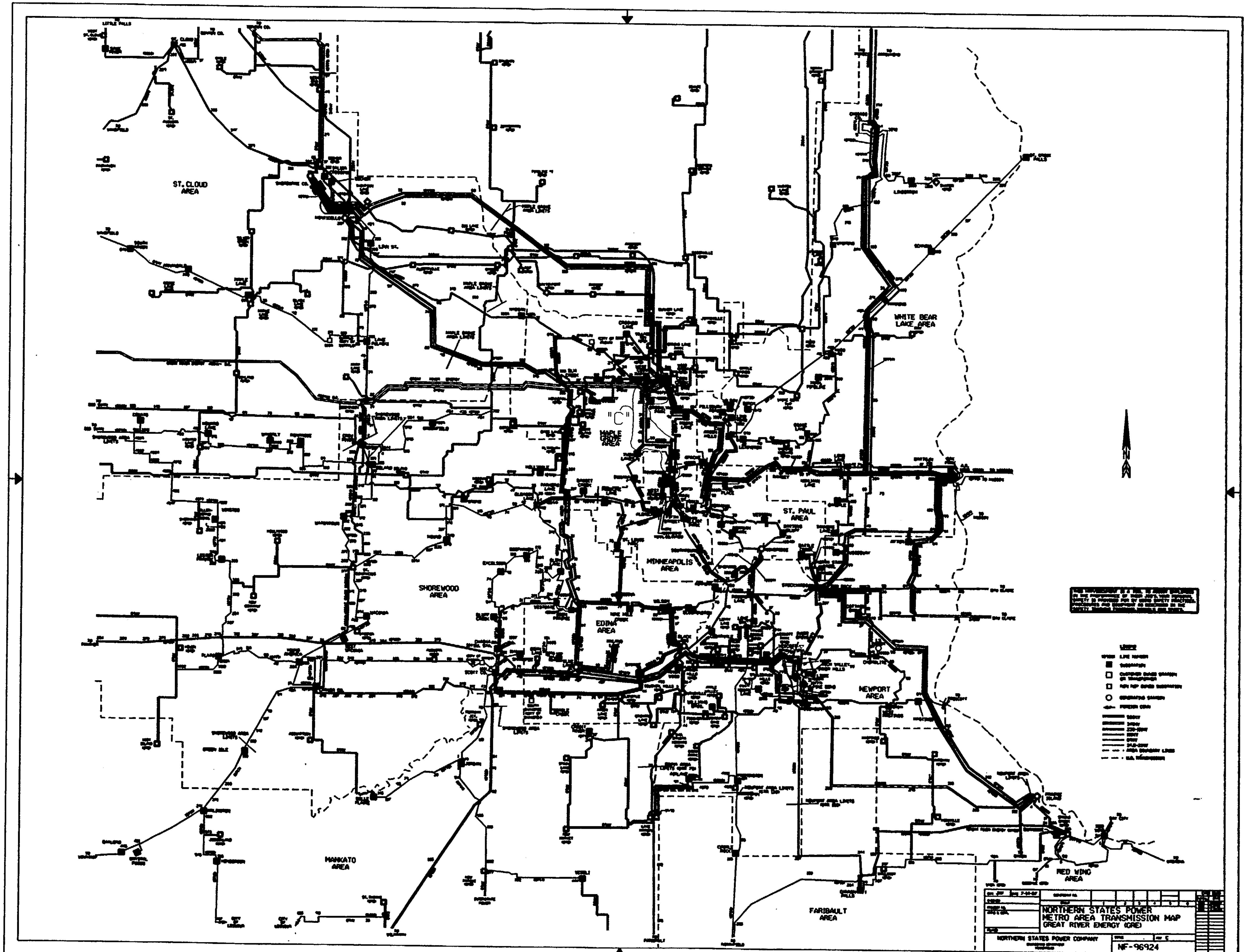

FIGURE 8.2-1 REV 23

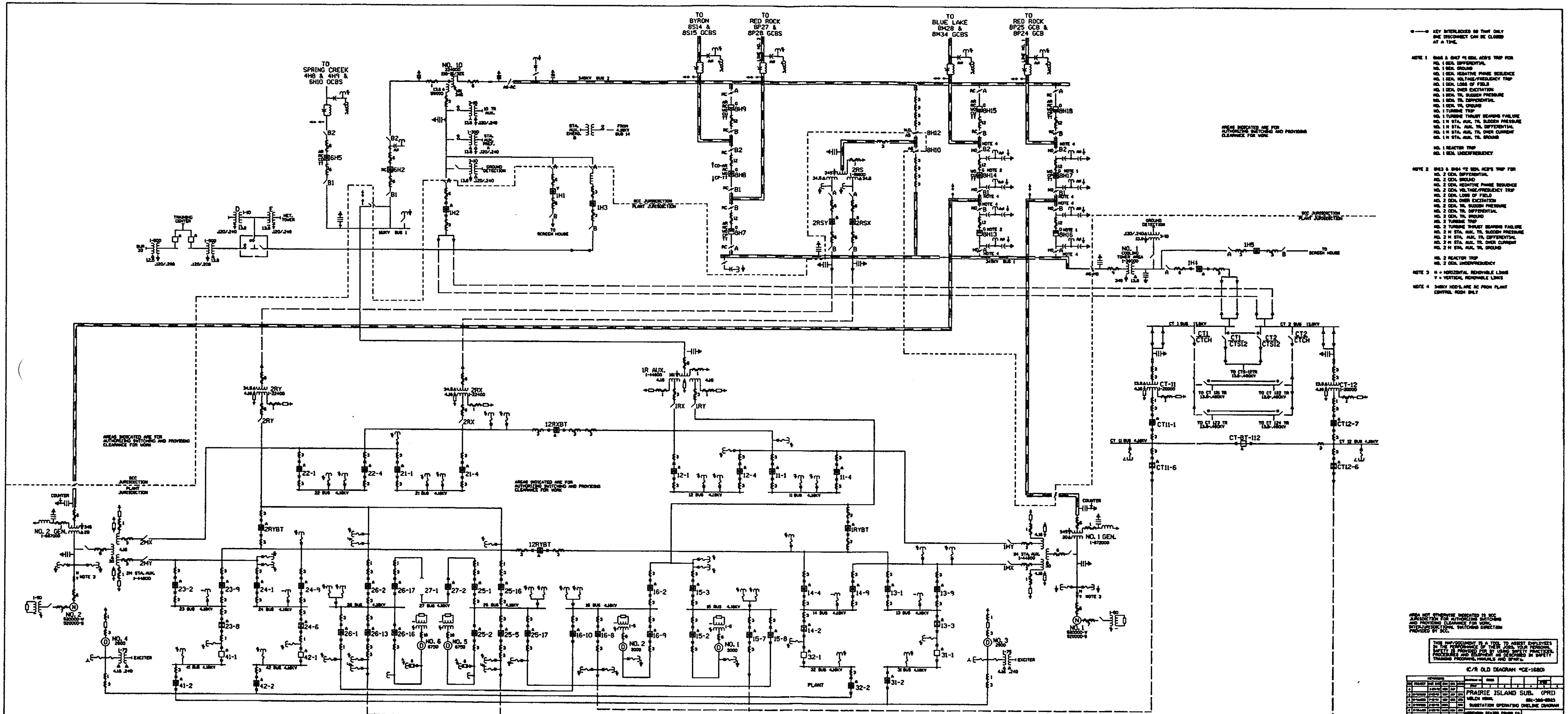

FIGURE 8.2-2 REV.23