FPL

10 CFR §50.59
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U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Re: Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251
10 CFR 50.59 Report

The summary report of changes, tests and experiments made without prior commission approval in accordance with 10 CFR 50.59 for the period April 7, 2002 through November 5, 2003 is attached (Attachment 1). The report also contains a summary of power operated relief valve (PORV) actuations, Technical Specification Bases changes, the results of any steam generator tube inspections occurring during the report period and reload safety evaluation summaries for Unit 3 Cycle 20 and Unit 4 Cycle 21. The updated Technical Specification Bases are provided in Attachment 2.

If there are any questions regarding the information contained in this submission, please contact Mr. Walter Parker at 305-246-6632.

Very truly yours,

Terry Jones

Terry O. Jones
Vice President
Turkey Point Nuclear Plant

Attachments: 1) 10 CFR 50.59 Summary Report (six sections)
2) Technical Specification Bases Control Program, Procedure 0-ADM-536

cc: Regional Administrator, Region II, USNRC
Senior Resident Inspector, USNRC, Turkey Point Nuclear Plant

IE47

2002 / 2003

10 CFR 50.59

SUMMARY REPORT

FLORIDA POWER & LIGHT COMPANY

TURKEY POINT UNITS 3 and 4

TURKEY POINT PLANT UNITS 3 AND 4

DOCKET NUMBERS 50-250 AND 50-251

CHANGES, TESTS AND EXPERIMENTS

MADE AS ALLOWED BY 10 CFR 50.59

FOR THE PERIOD COVERING

APRIL 7, 2002 THROUGH NOVEMBER 5, 2003

INTRODUCTION

This report is divided into six (6) sections. The first section summarizes those changes made to the facility as described in the UFSAR that were performed by a Plant Change/Modification (PC/M). The second section summarizes those changes made to the facility or procedures as described in the UFSAR that were performed by a 10 CFR 50.59 evaluation. This includes those changes not performed by a PC/M, and any tests and experiments not described in the UFSAR that were performed during this reporting period. The third section provides a summary of the Unit 3 and Unit 4 fuel reload evaluations. The fourth section provides a list of power operated relief valve (PORV) actuations. This section is included as part of FPL's commitment to comply with the requirements of Item II.K.3.3 of NUREG 0737. The fifth section of this report provides a summary of the findings of any steam generator tube inspections. The sixth section of this report provides Technical Specification bases changes made since issuance of Amendments 222 and 217 to the Unit 3 and 4 licenses, respectively. The amendments established a bases control program in Section 6 of the Technical Specifications.

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SECTION 1

PLANT CHANGE / MODIFICATIONS

PLANT CHANGE/MODIFICATION 95-035

UNIT : 3 and 4

TURN OVER DATE : 04/01/2003

ELIMINATE CAPABILITY FOR NITROGEN CAPPING OF EXTRACTION STEAM PIPING FOR OXYGEN CONTROL

Summary:

This Engineering Package (EP) provided the details and instructions necessary to abandon in-place/isolate the nitrogen capping system to various secondary side feedwater heaters and the steam jet air ejector (SJAE) condenser. The specific affected heaters and condenser for each unit are as follows: 3/4E4A & B heaters, 3/4E5A & B heaters, 3/4E6A & B heaters, 3/4T25A, B, C and D MSRs, and 4S4 SJAE condenser. The nitrogen capping system was designed to provide a blanket of nitrogen within feedwater heaters and the SJAE condenser during extended outages. The purpose of filling the vessels with a nitrogen blanket was to remove normally occurring dissolved oxygen, therefore eliminating or reducing the potential for internal metal surface oxidation/corrosion. During the first few years of plant operation following startup, it was ascertained that the nitrogen capping system was ineffective in controlling oxygen and was subsequently rarely if ever used. The in-place abandonment of the nitrogen capping system required other means of protecting the inner metal surfaces of the pressure vessels during extended outages. To fulfill this need, the plant was provided with a backfitted secondary wet layup system (in use since 1991) designed to recirculate water through the condenser, condensate system, and feedwater system including the shell side of the feedwater heaters. The secondary wet layup system prevents metal corrosion and provides a means to degassify and add chemicals to prevent excursions of water quality in the secondary system during extended unit shutdowns. A UFSAR change package was provided as an attachment to this modification package to remove references to nitrogen capping capabilities to the components discussed above.

10 CFR 50.59 Evaluation:

The EP provided guidance on installing various in-line pipe caps in place of existing pipe nipples to ensure both piping isolation and piping restraint of the noted nitrogen capping system hardware are maintained. The nitrogen capping components addressed in this EP did not serve any safety function and were not required for the safe shutdown of the plant. This EP was classified as non-safety related due to association with various non-safety related feedwater heaters. The exception to this classification are the high pressure feedwater heaters 6A and 6B which are quality related due to the seismic/structural integrity of their shells. The work associated with this EP did not adversely impact the structural integrity of these vessels. The in-place abandonment of the identified nitrogen capping system hardware did not adversely affect the design function of the feedwater heaters nor degrade the internal metallic surfaces. The equipment abandonment/isolation did not introduce any new failure modes or interactions with safety related equipment or functions. Since this modification did not impact safe operation of the plant or require changes to the plant technical specifications, prior NRC approval was not required for implementation.

PLANT CHANGE/MODIFICATION 95-124

Revision 0, Revision 1

UNIT: 4

TURN OVER DATE: 10/29/2003

REPLACEMENT OF CONTAINMENT PURGE VALVE ACTUATORS (POV-4-2600/2601)

Summary:

This Engineering Package (EP) provided the engineering and design necessary to replace the existing containment purge supply valve actuators with new actuators to improve reliability, operability and maintenance. Valve POV-4-2600 provides the outside containment isolation barrier for the containment purge supply penetration. Valve POV-4-2601 provides the inside containment isolation barrier for the containment purge supply penetration. The existing actuators for these valves required frequent maintenance, and spare parts were not readily available to service them because they were obsolete. The existing actuators utilized a dual spring / air canister design whereas the new actuators utilize a single spring / air canister design. The new actuators provide more torque and require less instrument air pressure than the existing models to achieve an opening and closing stroke. Additionally, one pressure control valve (PCV-4-2600 and PCV-4-2601) was added upstream of each of the new actuators. The purpose of the pressure control valves is to limit instrument air pressure to within the nameplate rating of the valves.

Revision 1 of this EP provided the engineering and design necessary to replace POV-4-2601.

Safety Evaluation:

The existing containment purge supply valves POV-4-2600 and POV-4-2601 were upgraded in this EP to improve reliability, operability, and maintenance. The activity was considered to be a design enhancement since the new actuators were similar in form, fit and function to the existing actuators. The containment purge supply valves are not considered to be accident initiators in the UFSAR. Since this modification did not increase the valve closure time, the consequences of an accident previously evaluated in the UFSAR were not increased. The replacement actuators were tested and qualified as suitable for operation in nuclear safety systems. Furthermore, the addition of an instrument air regulator in the instrument air supply tubing had no affect on the safety function of the purge supply valve. Postulated malfunctions of the instrument air system and/or the new air pressure regulators were evaluated and did not result in a malfunction of the purge supply valves. Additionally, the modification did not adversely affect the integrity, operation or function of any safety related system. No new hazards were created that could be postulated to cause an accident different than those previously analyzed. Since this modification did not impact the safe operation of the plant or require a change to the plant technical specifications, this EP was determined not to require prior NRC approval.

PLANT CHANGE/MODIFICATION 00-015

UNIT: 4

TURN OVER DATE: 05/09/2002

TURBINE LUBE OIL CONDITIONER REPLACEMENT

Summary:

This Engineering Package (EP) provided for removal of the turbine lube oil filtration system (Bowser/Delaval) from Unit 4 and replacing it with a self-contained skid-mounted oil conditioning system (Kayden TURBO-TOC). The replaced lube oil conditioning system was unable to maintain the oil within the vendor recommended purity criteria, and the maintenance costs associated with troubleshooting, repairing and maintaining the system (Bowser/Delaval) were excessive. The replacement oil conditioning system is a 100 gpm off-line pressure coalescence turbine oil conditioning system that continuously pumps the oil from the main turbine reservoir, cleans and dries the oil, and returns it under pressure to the reservoir. The purpose of this modification was to provide an equivalent replacement system capable of providing acceptable oil contamination levels consistent with applicable standards. The replacement equipment provides an improved design utilizing newer technology in oil conditioning based on a combination of coalescing and cartridge filter elements to remove solid contaminants as well as free water. The lube oil piping was rerouted to accommodate the connection points on the new oil conditioner. In addition to replacing the existing filtration system, this EP provides for raising a portion of the existing fire suspension ring protecting the lube oil conditioning area to avoid interference with the control panel on the new oil conditioning skid. A UFSAR change package for Section 10.2 was provided as an attachment to this modification package to delete reference to a specific lube oil conditioner manufacturer for Unit 4 and to remove details not pertinent to nuclear safety. In addition, UFSAR Appendix 9.6A was updated to address the reduction of the combustible loading for oils in Fire Zone 78.

10 CFR 50.59 Evaluation

The modification performed by this EP replaced the existing Unit 4 turbine lube oil conditioner units with a new conditioner of an improved design. The replacement conditioner is designed to be functionally equivalent in terms of automatic operation, particulate and water removal, and operating parameters. The lube oil conditioner associated tie-ins and supports are not safety related nor part of safety related design features. The modification did not have an effect on, or interact with safety related equipment, systems, or components. Process piping and components used were designed to accommodate the design and/or operating pressure and temperature of the turbine lubrication system. In addition, the current design of protecting from an external fault either at the oil conditioner or its associated piping from draining the reservoir below a critical level is maintained by means of a siphon break arrangement at the piping to the new lube oil conditioner. The additional pipe and fittings to the fixed water suppression system did not change the method of suppression system actuation or the spray pattern. Since this modification did not impact the safe operation of the plant or require a change to the plant technical specifications, this EP was determined not to require prior NRC approval.

PLANT CHANGE/MODIFICATION 00-041

UNIT: 3 & 4

TURN OVER DATE: 04/25/2002

APPENDIX R MODIFICATION TO ATMOSPHERIC STEAM DUMP VALVES

Summary:

The Atmospheric Steam Dump Valves (ADVs) are normally pneumatically controlled from hand/auto stations in the control room. The pneumatic control of the ADVs is configured such that control of the valves can be transferred to the alternate shutdown panel (ASP) by energizing a solenoid valve for each ADV. The ADV control is normally aligned to the control room but is transferred to the ASP only during a postulated fire that requires control room evacuation. A condition report evaluation identified possible inadvertent transfer of ADV controls from the control room to the ASP panels if the solenoid valves are spuriously energized due to adverse fire affects in fire areas U/67 (Unit 4) and W/70 (Unit 3). This would cause a loss of control of ADV from the control room as well as from the ASP since these panels are located in the postulated fire areas.

The purpose of this Engineering Package (EP) was to install a 1/4-inch manual three-way valve in the pneumatic control tubing of each ADV such that the spurious transfer of the controls can be mitigated. This manual valve was installed between the ADV and its solenoid valve. During normal plant operation the three-way valve is aligned and locked such that the pneumatic control signal from the control room passes through the normally de-energized solenoid valve and the manual valve. In the event of a postulated fire when the solenoid valve is spuriously energized, the pneumatic control can inadvertently transfer to the ASP. During this scenario the manual valve will be placed in "isolate" position to align the valve to the control room signal directly and block pneumatic signal from the ASP through the solenoid valve. Thus, the signal from the ASP will be blocked but the signal from the control room will be established. This modification was performed for ADVs CV-3-1606, 1607, 1608 for Fire Area W/70 and for CV-4-1606, 1607, 1608 for Fire Area U/67. This modification required that a new manual action be added to the safe shutdown analysis at the main steam platform and that additional emergency lighting be added for operator ingress/egress.

10 CFR 50.59 Evaluation

Potential failure modes were reviewed to determine their impact on nuclear safety. All new components that were installed were of the same quality standards of the original components in the pneumatic control system and did not involve a change in the functional configuration or operation of the existing pneumatic control or ADV valve operators. The manual valves are passive components and the imposition of administrative controls precludes inadvertent operation. The new manual valves were configured such that there is no change in the backup nitrogen system associated with the ADVs. Therefore, no new failure modes were introduced with this change. The modification performed enhanced the ability of the ADVs to perform as intended during specific fire scenarios. The ADVs are not considered to be accident initiators in any accident sequence evaluated in the UFSAR and the modification did not increase the consequences of an accident described in the UFSAR. No new hazards are created that can be postulated to cause an accident of a different type than those previously analyzed. Since the modification did not compromise plant safety or require any change to the plant technical specifications, prior NRC approval was not required for implementation.

PLANT CHANGE/MODIFICATION 01-012

UNIT: 3

TURN OVER DATE: 03/12/2003

AUXILIARY FEEDWATER (AFW) BUS STRIPPING RESET MODIFICATION

Summary:

This Engineering Package (EP) provided justification and instructions for revising the auxiliary feedwater (AFW) bus stripping actuating circuits such that the AFW auto start relays automatically reset after a sufficient time delay for the AFW pumps to have started. Previously, the AFW auto start relays did not reset when actuated from a bus stripping signal from the load sequencers until the start-up transformer breaker was closed. The EP adds time delay and interposing relays in the circuitry that initiates the AFW auto start relays such that the auto start relays will reset after two minutes when these relays have been actuated from a bus stripping signal from the load sequencers. Resetting the autostart relays will not cause any valves to change position. The change improves the control room operators' ability to manage the operation of the AFW system and to more expeditiously shutdown AFW if it is not needed, when AFW operation is initiated from a stripping signal.

10 CFR 50.59 Evaluation

Bus stripping is an anticipatory start signal for loss of offsite power (LOOP) and is not the primary actuation signal for any design basis event described in the UFSAR. The LOOP event analysis is based on AFW start from a low-low steam generator water level signal. AFW pump start is required from a bus stripping signal by technical specifications in Modes 1, 2 and 3. Although the added relay introduces another failure possibility, the significance is minimal due to the multiple redundancy for AFW actuation due to other means (loss of last running feed pump, safety injection, low-low steam generator level and manual). This modification makes no changes to the AFW start functions that serve as a basis for mitigating FSAR Chapter 14 events. This evaluation concluded that the modification did not impact the safe operation of the plant or require a change to the plant technical specifications, and thus did not require NRC approval prior to implementation.

PLANT CHANGE/MODIFICATION 02-004

UNIT: 4

TURN OVER DATE: 04/12/2002

CORE EXIT THERMOCOUPLE INSTALLATION VIA IN-CORE SYSTEM FLUX THIMBLE FOR LOCATIONS H1 AND M3

Summary:

The purpose of the Engineering Package (EP) was to restore two of the 13 core exit thermocouples (CETs) that were lost during the Unit 4 cycle 17 refueling outage when CET support column 53 was damaged. CET TE-4-46E was restored at its original core location (M-3) by insertion into the fuel assembly through the thimble tube. CET TE-4-16E was restored to location H-1, adjacent to its previous location in J-2, also by thimble tube insertion. The new replacement thermocouple locations met the described NUREG-0737 core exit locations. Mineral insulated thermocouple wires with inconel sheath were inserted into the existing in-core thimble tubes. These wires exit the thimble tubes at the seal table, outside the reactor coolant system (RCS) pressure boundary. Environmentally qualified extension wires were routed from the seal table to existing containment electrical penetrations. The replacement thermocouples provide equivalent temperature readings compared to the existing CET for their respective locations. This EP restored two CETs at the expense of eliminating two in-core detector thimbles. However, the requirements of the technical specifications and the description in the UFSAR for each system (CET and thimbles) are met with sufficient margin. A UFSAR change package was provided as an attachment to the EP to describe the change to the CETs and flux mapping thimble tubes.

10 CFR 50.59 Evaluation:

This EP restored two CETs in core quadrant 2 to operable status by inserting CET sensors into in-core detection system thimble tubes at locations M-3 and H-1. An evaluation of the failure rate and modes of failure determined that the new CET configuration was equivalent to the existing components, and as such no increase in the frequency of failure existed, and there was no increase in the frequency of occurrence of accidents. The change did not physically alter equipment, system performance, or operator actions in a manner that adversely impacted UFSAR analyses. The changes did not create new malfunctions or introduce new credible failure modes. The use of existing RCS pressure retaining thimble tubes for new CET thermocouple locations coupled with the fact that no new credible failure modes were created eliminated the potential for increasing the consequences of an accident previously evaluated in the UFSAR. The use of existing thimble tubes and minor changes to the qualified safety parameter display system (QSPDS) similarly eliminated the potential for increasing the consequences of accidents previously evaluated in the UFSAR. In addition, the modifications did not introduce the possibility of a new accident. A Failure Modes and Effects Analysis specifically addressed the potential for thimble tube failure due to mechanical interaction as a result of permanent CET installation and the impact of using grounded vs. ungrounded thermocouples was evaluated with no new credible failure mechanisms created. The use of existing thimble tube locations to restore CET capability did not affect any controlling numerical values presented in the UFSAR used to determine the integrity of a fission product barrier. Since this modification did not impact safe operation of the plant or require a change to the plant technical specifications, this EP did not require prior NRC approval.

PLANT CHANGE/MODIFICATION 02-006

UNIT : 3 & 4

TURN OVER DATE : 05/29/2003

CONTROL ROOM EMERGENCY VENTILATION SYSTEM (CREVS) BACKUP FAN (SF1A) STARTUP TIME DELAY (2X/LOFL)

Summary:

The Control Room Emergency Ventilation System (CREVS) is designed and operated to minimize the effects on control room operators of an accidental release of radioactive gases. The design is such that on a valid actuation signal, specified motor operated control room dampers reposition and a single emergency supply fan (SF-1B) is started to recirculate a portion of the control room atmosphere through HEPA and charcoal filters. A backup fan (SF-1A) is started if a low flow condition is sensed within a specified period of time after the initial actuation signal. A condition report evaluation noted that the existing set point of 30 seconds might not provide sufficient time to allow the first fan to develop full flow therefore allowing the possibility of two fans running at the same time. Two fans operating simultaneously would decrease the radioactive gas residence time in the charcoal filter below required values. The purpose of this Engineering Package (EP) was to provide the required documentation, justification, and instructions to increase the SF-1A start signal time delay from 30 seconds to 75 seconds to reduce the possibility of two fans running at the same time. The existing low flow time delay relay is an Agastat Model 7012AE with an adjustable setting from 20 to 200 seconds. The setting was changed from the existing setting of 30 seconds to a setting of 75 +/- 5 seconds. No additional components were added to the plant as a result of this EP.

10 CFR 50.59 Evaluation:

The EP changed the time delay for the startup of a redundant CREVS backup emergency supply fan from 30 seconds to 75 seconds. The function of the low flow time delay is to provide sufficient time for the first fan to start and provide a minimum flow of 300 cfm prior to starting the second fan. The increase in the delay time will prevent unnecessary cycling of the backup supply fan. An evaluation of the safety significance of a delay in the start time of the redundant fan determined that a 2-3 minute delay in actuating the emergency pressurization mode could easily be tolerated without increasing the control room dose. It was concluded that the failure of the redundant supply fan to automatically start due to the failure of the SF-1B would not result in exceeding General Design Criterion 19 limits and would not significantly degrade plant safety. In addition, the modification would not affect the conclusion of the radiological dose evaluation (Section 14.2.1.2) of the UFSAR Fuel Handling Accident. No new equipment was added and the control circuitry for the primary supply fan (SF-1B) was not modified. Since the EP did not impact safe operation of the plant or require changes to the plant technical specifications, prior NRC approval was not required for implementation.

PLANT CHANGE/MODIFICATION 02-031

UNIT : 3

TURN OVER DATE : 04/08/2003

ABANDONMENT OF HYDROGEN RECOMBINER EXHAUST LINE TO CONTAINMENT AND REPLACEMENT OF CHECK VALVE 3-40-205

Summary:

Issuance of the NRC approved exemption to 10 CFR 50.44 eliminated the need for the hydrogen recombiner and Post Accident Containment Vent (PACV) system at Turkey Point Units 3 and 4. Consistent with this, the PACV system was removed from the plant technical specifications by Amendments 217/211. This design change eliminated the portions of these systems that affected containment penetration 34, thereby reducing the amount of testing and maintenance required by this penetration. Penetration 34 provides service air supply to the containment. Service air is used for pneumatic tools for maintenance activities. Service air is also used to pressurize containment for post-accident venting. Penetration 34 also provides a return path to containment from the hydrogen recombiner. This Engineering Package (EP) cut and capped the hydrogen recombiner return branch of the penetration and replaced the service air check valve 3-40-205 with a locked manual isolation valve. A UFSAR change package was provided with the EP to reflect changes made to containment penetration 34 and update the appropriate descriptions and design information.

10 CFR 50.59 Evaluation:

This EP abandoned in place the exhaust line from the hydrogen recombiner and reconfigured the containment isolation features for containment penetration 34, based on the NRC-approved exemption to 10 CFR 50.44 and issuance of Amendments 217/211 removing the PACV system from the Technical Specifications. The structures, systems and components affected by these changes are not accident or event initiators as described in the UFSAR. The modified valving arrangements on penetration 34 (replacing a swing check valve with a locked closed manual isolation valve and cutting and capping the hydrogen recombiner branch line) reduced the number of components necessary to maintain the containment function. The changes did not adversely affect the existing level of protection against the release of radioactivity to the outside atmosphere. The reconfigured penetration 34 satisfies the UFSAR single active failure criterion for containment isolation. The barriers credited for maintaining the isolation function consist of two manual isolation valves in series. Therefore, these modifications did not increase the frequency or likelihood of occurrence or result in more than a minimal increase in the consequences of an accident or malfunction of an SSC important to safety previously evaluated in the UFSAR. No new failure modes were created. Therefore, the change did not create the possibility for an accident or for the malfunction of any SSC important to safety of a different type or with a different result than any previously evaluated in the UFSAR. The modification did not result in altering or exceeding a design basis limit for a fission product barrier as described in the UFSAR or in a departure from a method of evaluation described in the UFSAR used in establishing the design bases or in the safety analyses. Therefore, as these changes were performed based on receipt of the NRC exemption and approved plant technical specification changes, no further NRC approval was required for implementation.

PLANT CHANGE/MODIFICATION 02-050

UNIT : 3

TURN OVER DATE : 03/19/2003

PERMANENT PLATFORM/SCAFFOLDING/COMPONENTS IN CONTAINMENT

Summary:

The purpose of this Engineering Package (EP) is to install permanent structures and components inside the Unit 3 containment that will replace temporary structures and components that are usually installed and removed during each outage. The structures installed are scaffolding platform frames, scaffold storage racks, and fixed ladders. The components installed are storage barrels. The scaffolding platform frames are used for performing maintenance on the steam generators, reactor coolant pumps, normal containment coolers, and to connect temporary power. The storage racks will be used for storage of scaffold poles that will remain in containment. The ladders are used for access to the inspection ports on the steam generators and the barrels are used for the storage of knuckles that are used to build platforms during plant outages. Implementation of this EP reduces personnel dose and time spent in containment by craft personnel during plant outages, since all or portions of the platforms will already be in place and the poles and knuckles to complete the scaffold platform frames will already be in containment.

10 CFR 50.59 Evaluation:

The potential adverse affects associated with seismic events, the potential impact on hydrogen generation, adverse affects on containment free volume and bulk material inventory affects related to heat sinks, potential fire hazards affects, containment sump interactions, jet impingement, post-LOCA flood levels, pressurization, air flow, thermal loads and secondary missile effects were considered in the design of these new components and structures. Restrictions imposed in this EP to ensure that the plant design bases with respect to seismic and high energy line break considerations were not compromised. There are no credible failure modes associated with the new structures and components that could adversely affect safety related structures, systems, or components. Therefore, since these changes did not adversely affect safe plant operation or require a change to the plant technical specification, NRC approval was not required prior to implementation.

PLANT CHANGE/MODIFICATION 03-033

UNIT : 4

TURN OVER DATE : 10/29/2003

PERMANENT PLATFORMS/SCAFFOLDING/COMPONENTS IN CONTAINMENT

Summary:

Engineering Package (EP) 02-012 was previously issued to install permanent structures and components inside the Unit 4 containment that replaced temporary structures and components that are usually installed and removed during each outage. This EP was prepared to reinstate a number of items that were not installed under EP 02-012 due to time restraints, and which are considered necessary to support maintenance activities during Unit 4 outages. The items included under the scope of this EP are 1) Reactor Coolant Drain Tank (RCDT) fence frame, 2) ladders permanently affixed to the A, B, and C Steam Generator cubicle walls, and a storage barrel in the Reactor Coolant Pump C cubicle. The ladders will be used for access to the inspection ports on each steam generator. The fence frame was installed around the RCDT to form a barrier to prevent personnel from accessing the area around the RCDT which is a locked high radiation area. The frame can be used to hang temporary lead shielding blankets during outages. The single barrel will be used for storage of knuckles and scaffolding connectors used during the unit outages. Having these components permanently inside the containment reduces time personnel spend building temporary structures or placing ladders for access to the Steam Generator inspection ports. Minimizing the use of temporary structures and components reduce personnel dose during outages.

10 CFR 50.59 Evaluation:

The potential adverse affects associated with seismic events, the potential impact on hydrogen generation, adverse affects on containment free volume and bulk material inventory affects related to heat sinks, potential fire hazards affects, containment sump interactions, jet impingement, post-LOCA flood levels, pressurization, air flow, thermal loads and secondary missile effects were considered in the design of these new components and structures. Restrictions imposed in this EP to ensure that the plant design bases with respect to seismic and high energy line break considerations were not compromised. There are no credible failure modes associated with the new structures and components that could adversely affect safety related structures, systems, or components. Therefore, since these changes did not adversely affect safe plant operation or require a change to the plant technical specification, NRC approval was not required prior to implementation.

SECTION 2

10 CFR 50.59 EVALUATIONS

10 CFR 50.59 EVALUATION JPN-PTN-SEEJ-88-042
Revision 12

UNIT: 4

APPROVAL DATE: 09/09/2003

DE-ENERGIZATION OF UNIT 4 4160 VOLT SAFETY RELATED BUSES TO ALLOW FOR MODIFICATIONS OR PERIODIC MAINTENANCE

Summary:

This evaluation was developed to establish the requirements and restrictions which must be placed on the operation of Units 3 and 4 and their equipment when a Unit 4 4160 volt bus is de-energized and train "A" and "B" load centers are cross-connected. Also examined were technical and licensing concerns associated with de-energizing safety related equipment and effectively removing an emergency diesel generator (EDG) from service as the result of a Unit 4 4160 volt bus de-energization. The de-energization of a Unit 4 4160 volt safety related bus, with Unit 4 in cold or refueling shutdown (Modes 5 and 6) or de-fueled and Unit 3 at power operation (Mode 1) or below, is sometimes necessary to allow for periodic maintenance, testing, or design modifications of the 4160 volt switchgear. De-energization of a 4160 volt bus would cause de-energization of the 480 volt load centers and motor control centers powered from that bus, if any, and a loss of power to equipment which may be required to maintain cold/refueling shutdown, perform outage related activities, or support safe shutdown and accident mitigation on the opposite unit. This condition was alleviated by closing the tie-breakers between opposite train 480 volt load centers, while one 4160 volt bus was de-energized or by ensuring that alternate equipment was available.

Revision 12 of this evaluation was revised to change the load on the Portable Welding Load Center #4 feeder breaker (LC 4B, Breaker # 40212) from 120 Amps to 160 Amps to support outage power estimated to be 140 Amps. The evaluation showed that the new calculated load on Load Center 4B remain within the capabilities of the evaluated onsite electrical power distribution equipment and system. In addition, in the event of a loss of voltage, the Portable Welding Load Center #4 would not be loaded onto the EDG. In addition, Revision 12 reflects a load increase of 71HP on each of the Circulating Water Pump motors. This load increase has been evaluated for the effects on the 4160 volt bus analysis results and determined to be acceptable.

10 CFR 50.59 Evaluation:

This evaluation addressed the technical and licensing requirements for the de-energization of each Unit 4 4160 volt bus and concluded that the proposed plant configuration and mode of operation was bounded by the technical specifications and did not change the accident analyses addressed in the UFSAR or the results and conclusions of any previous 10 CFR 50.59 evaluation. The actions or procedural changes identified and evaluated in this 10 CFR 50.59 evaluation did not have any adverse affect on plant safety or plant operations and did not require changes to plant technical specifications. Therefore, prior NRC approval was not required for implementation of the actions or precautions identified in this 10 CFR 50.59 evaluation.

10 CFR 50.59 EVALUATION JPN-PTN-SEMS-90-041
Revision 8

UNIT: 3

APPROVAL DATE: 12/12/2002

ACCEPTABILITY OF AS-FOUND CONDITION FOR RHR CHECK VALVE 3-753A

Summary:

This safety evaluation examined the as-found metallurgical defects in the residual heat removal (RHR) system 3A pump discharge check valve 3-753A. In response to Significant Operating Experience (SOER) 86-3, Turkey Point implemented a disassembly and inspection program on a sampling basis to ensure check valve internals were intact and were not experiencing abnormal wear. During visual inspection of the 3A RHR pump discharge check valve, three linear indications were identified on the valve seat. One of the indications cut across the stellite seat and extended into the austenitic stainless steel valve body. A liquid penetrant examination determined that the other two defects met the acceptance criteria of ASME Section III. A flaw evaluation was conducted consistent with the analytical flaw evaluation methods contained in ASME Section XI (IWB-3600). Based on this review and the material behavior for the cast austenitic stainless steel valve body, the only relevant degradation expected was fatigue. Due to the low calculated crack growth for the estimated valve duty cycles, it was concluded that the valve would provide acceptable operation until the end-of-service life of the plant.

Revision 8 to this evaluation provided a technical basis for the continuation of the five-year inspection frequency for check valve 3-753A. Based on review of the original and re-inspection data, as well as a review of the 1990 and 1992 flaw evaluation calculations, the following was concluded: 1) Since no flaw growth was observed for the original flaw since 1992, the assumptions on crack size and crack growth in the original calculation are still valid and conservative. Based on similarity in size, location, loading conditions, etc., the assumptions are also applicable to the second flaw identified in 2001; 2) the loading conditions for future operation are unchanged from past operation history, and these conditions have been treated in a bounding manner in the original flaw evaluation; 3) A preventive maintenance re-inspection interval of five years (60 months) for valve 3-753A is adequate to monitor any potential changes for the remaining life of the valve.

10 CFR 50.59 Evaluation:

Inspections and evaluations have shown that there has been no crack growth of the original flaw since 1992. Based on similarity in size, location, loading conditions, etc., the assumptions for the original flaw are also applicable to the second flaw identified in 2001. The evaluation confirmed that the preventive maintenance and re-inspection interval of five years (60 months) is adequate to monitor any potential changes for the remaining life of the valve. Since the as-found condition of the valve will not impact the capability of the RHR system to perform its safety functions (effectively until the end-of-service life of the plant), the actions or plant conditions identified in this 10 CFR 50.59 evaluation did not have any adverse impact on plant safety and did not require changes to plant technical specifications. Therefore, prior NRC approval was not required for implementation of the actions or conditions identified within this 10 CFR 50.59 evaluation.

10 CFR 50.59 EVALUATION JPN-PTN-SENP-95-007
Revision 6

UNIT: 3

APPROVAL DATE: 02/27/2003

OPERABILITY OF RESIDUAL HEAT EXCHANGER AND REFUELING SUPPORT EQUIPMENT DURING INTEGRATED SAFEGUARDS TESTING

Summary:

This evaluation reviewed the Unit 3 engineered safeguards integrated test (ESIT) procedures with respect to a generic Westinghouse concern related to the effectiveness of the steam generators (S/Gs) to remove decay heat during shutdown conditions. Westinghouse identified that there was a potential for gas formation within the steam generator U-tubes under certain reactor coolant system (RCS) pressure and level conditions in Mode 5 that could inhibit the ability to establish natural circulation cooling. To accommodate the potential unavailability of the S/Gs for decay heat removal under these conditions, plant technical specifications require that both trains of the residual heat removal system (RHR) be operable in Mode 5 when the RCS is in a "loops not filled" configuration. Since safeguards testing was normally performed during Mode 5 with the RCS depressurized and partially drained, this evaluation was developed to document that both trains of the RHR system would remain operable during the test period. The evaluation concluded that no restrictions on plant operations or additional operator actions, other than those already prescribed in the ESIT procedures, were required to ensure RHR operability.

Revision 6 expanded the scope of this evaluation to address operability of the refueling support equipment during performance of the ESIT in Mode 6 during core reload. It also clarifies assumptions made previously in addressing operability of refueling support equipment during ESIT performance including spent fuel pool cooling and component cooling (CCW) water flow through an inoperable CCW heat exchanger. Additionally, this revision considered procedural enhancements with respect to operation of the containment ventilation system when the ESIT is performed during core alterations.

10 CFR 50.59 Evaluation:

This 10 CFR 50.59 evaluation examined the electrical, mechanical, and hydraulic configuration of the plant during performance of the ESIT in Modes 5 (loops not filled) and 6 (vessel level two feet below the flange). Actions and limitations were identified to ensure that both RHR loops would remain operable during the test sequence. Appropriate actions and limitations were also identified for the refueling support equipment to ensure core offload/reload could be conducted during portions of the ESIT provided that identified actions and restrictions are complied with. The evaluation also examined heat removal capability, tube vibration, thermal stress, and pressure boundary integrity of a CCW heat exchanger if it is operated without intake cooling water (ICW) flow during the test. The actions and limitations identified and evaluated in this 10 CFR 50.59 evaluation did not have any adverse affect on plant safety or operations. No new failure modes were created. Since all licensing and design basis requirements would continue to be met during the ESIT and the proposed activity did not require changes to plant technical specifications, prior NRC approval was not required to initiate the test sequences.

10 CFR 50.59 EVALUATION JPN-PTN-SENP-95-023
Revision 7

UNIT: 4

APPROVAL DATE: 10/04/2003

OPERABILITY OF PLANT EQUIPMENT DURING INTEGRATED SAFEGUARDS TESTING

Summary:

This evaluation reviewed the Unit 4 engineered safeguards integrated test (ESIT) procedures with respect to a generic Westinghouse concern related to the effectiveness of the steam generators (S/Gs) to remove decay heat during shutdown conditions. Westinghouse identified that there was a potential for gas formation within the steam generator U-tubes under certain reactor coolant system (RCS) pressure and level conditions in Mode 5 that could inhibit the ability to establish natural circulation cooling. To accommodate the potential unavailability of the S/Gs for decay heat removal under these conditions, plant technical specifications require that both trains of the residual heat removal system (RHR) be operable in Mode 5 when the RCS is in a "loops not filled" configuration. Since safeguards testing was normally performed during Mode 5 with the RCS depressurized and partially drained, this evaluation was developed to document that both trains of the RHR system would remain operable during the test period. The evaluation concluded that no restrictions on plant operations or additional operator actions, other than those already prescribed in the ESIT procedures, were required to ensure RHR operability.

Revision 7 expanded the scope of the evaluation to address a concern raised in a condition report regarding the performance of ESIT in conjunction with fuel movement. Specifically, this evaluation addressed procedural enhancements with respect to the operation of the containment ventilation system isolation during ESIT performance. Additionally, this revision incorporated the implementing engineering evaluation PTN-ENG-SEMS-03-003 associated with the NRC approved 72-hour post-shutdown license amendment.

10 CFR 50.59 Evaluation:

This 10 CFR 50.59 evaluation examined the electrical, mechanical, and hydraulic configuration of the plant during performance of the ESIT in Modes 5 (loops not filled) and 6 (vessel level two feet below the flange). Actions and limitations were identified to ensure that both RHR loops would remain operable during the test sequence. Appropriate actions and limitations were identified for the refueling support equipment to ensure core reload could be conducted during portions of the ESIT. The evaluation also examined heat removal capability, tube vibration, thermal stress, and pressure boundary integrity of a component cooling water (CCW) heat exchanger if it is operated without intake cooling water (ICW) flow during the test. The actions and limitations identified and evaluated in this 10 CFR 50.59 evaluation did not have any adverse affect on plant safety or operations. No new failure modes were created. This evaluation ensures that regardless of the test configuration utilized, the associated RHR train is operable and can be immediately started and effectively operated from the control room without local actions during performance of the ESIT with the plant in Mode 5 or Mode 6. Since all licensing and design basis requirements would continue to be met during the ESIT and the proposed activity did not require changes to plant technical specifications, prior NRC approval was not required to initiate the test sequences.

10 CFR 50.59 EVALUATION JPN-PTN-SEMS-96-038
Revision 5, Revision 6

UNIT: 3

APPROVAL DATE: 05/28/2003, Rev. 6

APPROVAL DATE: 05/13/2002, Rev. 5

STEAM GENERATORS' SECONDARY SIDE FOREIGN OBJECTS

Summary:

This evaluation addressed the potential safety significance of operating the Unit 3 steam generators (S/Gs) with foreign objects present in the secondary side. The foreign objects identified within the scope of this evaluation are those which are considered to be irretrievable. Previously, individual safety evaluations addressed the acceptability of continued Unit 3 operation while these foreign objects remained in the S/Gs and associated systems. The purpose of this evaluation was to: (1) re-examine the analyses, results, requirements, and restrictions of previous evaluations while applying recent industry standards; (2) document the methodology for determining the interval between S/G eddy current tests as affected by estimated S/G tube wall wear times; and (3) provide a single Unit 3 10 CFR 50.59 Evaluation to assess and document all of the Unit 3 S/G foreign object estimated wear times as adjusted by updated S/G eddy current data (ECT) and S/G Foreign Object Search and Retrievals (FOSAR) results.

Revision 5 modified the evaluation to be consistent with the changes made to the requirements of 10 CFR 50.59. This revision incorporated results from the ECT and FOSAR activities for all S/Gs and an extended visual inspection within the tube bundle of the 3C S/G conducted during the Unit 3 Cycle 19 refueling outage (RFO). The full-length ECT inspection activities implemented during the Unit 3, Cycle 19 RFO, coupled with inspection activities from the previous refueling outage, complete a 100% ECT inspection of all S/Gs. All wear time estimates within this evaluation were updated on that basis. Revision 6 incorporates results from the ECT and FOSAR activities for all S/Gs conducted during the Unit 3, Cycle 20 RFO. A total of three tubes required plugging in two of the three S/Gs. The full-length ECT inspection activities implemented in the Unit 3 Cycle 20 RFO complete a 100% ECT inspection of all S/Gs. All wear time assessments within this evaluation were updated on that basis.

10 CFR 50.59 Evaluation:

Previous 10 CFR 50.59 evaluations prepared for each S/G secondary side foreign object have considered the effects of the object upon tube integrity, chemistry, S/G instrumentation, the main steam system, and S/G blowdown and sampling systems. This evaluation establishes current wear time to minimum tube wall thickness estimates based on conservative assumptions from Westinghouse WCAP-14258 and associated Westinghouse clarification correspondence. These wear times assume worst case conditions and actual wear times are likely to be much greater than the Westinghouse methodology would predict. Based on this assessment, this evaluation determined that currently identified foreign objects within the secondary side of the Unit 3 S/Gs did not result in more than a minimal impact on any safety related design function and did not require a change to the plant technical specifications. Therefore, prior NRC approval was not required for continued operation of the plant with foreign objects present in the secondary side of the S/Gs, or endorsement of programmatic actions identified within this evaluation.

10 CFR 50.59 EVALUATION PTN-ENG-SECS-98-058

Revision 4

UNIT: 3

APPROVAL DATE: 03/17/2003

EVALUATION FOR STORAGE OF TOOLS AND EQUIPMENT IN CONTAINMENT DURING ALL MODES OF OPERATION

Summary:

This evaluation addressed the acceptability of leaving a quantity of tools and equipment within the Unit 3 containment structure during all modes of plant operation. The items to be stored, and the storage locations within the Unit 3 containment, were specifically identified within the evaluation. The purpose of leaving these tools and equipment within containment following refueling outages was to reduce the usage demand on the Unit 3 polar crane during refueling outages. This evaluation considered the potential for adverse seismic interactions with safety related equipment, the potential for additional hydrogen generation within containment during accidents, the impact on the containment free volume and heat sink analyses, the potential to obstruct flow to the containment sumps, and the impact on containment combustible loading. To ensure that the tools and equipment addressed in the evaluation were safely stored during plant operation, both generic and specific actions and restrictions were identified for implementation within the evaluation.

Revision 4 of this evaluation addresses the permanent storage of one control rod drive mechanism (CRDM) fan/motor assembly and two filter/vacuum units, and the temporary storage of the reactor head shield assembly in the Unit 3 containment. The evaluation concludes that these units can remain in the containment during all modes of operation provided that all of the requirements stipulated in this evaluation are followed. This revision also deletes all reference to material addressed under revision 3 of this evaluation since these materials have been removed from containment.

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 evaluation concluded that the identified items could safely remain within containment during all modes of operation, provided that all of the restrictions and requirements identified within the evaluation were implemented following each outage. The evaluation further concluded that the identified restrictions and requirements would ensure that these activities would have no adverse effects on plant operation, and would not compromise the safety and licensing bases of the plant. Consequently, the requirements and restrictions identified in this 10 CFR 50.59 evaluation did not adversely affect plant safety or require changes to the plant technical specifications. Therefore, prior NRC approval was not required for implementation of the requirements or restrictions identified within this evaluation.

10 CFR 50.59 EVALUATION PTN-PENG-SENS-00-046
Revision 4

UNIT: 4
APPROVAL DATE: 11/22/2002

SAFETY EVALUATION FOR TEMPORARY LOWERING OF UNIT 4 SPENT FUEL POOL WATER LEVEL FOR MAINTENANCE ACTIVITIES

Summary:

This evaluation was developed to examine the effects of securing the spent fuel cooling pumps and reducing the pool level by about 1-foot in order to perform maintenance on valve 4-821 in the primary water system makeup line to the spent fuel pool (SFP). This evaluation addressed the effects of spent fuel handling accidents, SFP heatup rates, increased radiation levels resulting from lowered water (shielding) levels, and activation of system alarms. To reduce the potential for fuel handling accidents, all fuel movement and crane operation were suspended in accordance with Technical Specification 3/4.9.11. Considering the amount of decay time that has elapsed since the previous refueling (Cycle 18), pool heatup from 100 °F to 135 °F was estimated to take about 18 hours, which would be a sufficient time to perform the required maintenance. Previous evaluations of reduced water levels have demonstrated that expected increases in radiation levels would be negligible. In order to preclude activation of the SFP alarms, pool temperature and level were required to be monitored on an hourly basis. A SFP temperature limit of 130 °F was established as an upper limit during the maintenance activity, at which time work would be secured and SFP cooling restored.

Revision 4 of this evaluation supports securing Unit 4 SFP cooling and lowering Unit 4 SFP level approximately 1 foot in support of coincidental maintenance activities on the demineralized water supply to SFP isolation valve (4-821) and on valve 4-798B in the filtration return header to the SFP during Operating Cycle 20. This revision also updated the associated restrictions and required actions identified in this evaluation.

10 CFR 50.59 Evaluation:

This evaluation concluded that reducing the spent fuel pool level for coincident maintenance on the primary water makeup valve and valve 4-798B in the filtration return header to the SFP would not adversely impact plant operation, and would not compromise the spent fuel handling accident analyses provided that the actions and restrictions identified in the evaluation were observed. Consequently, the reduced pool water level and other actions identified in this safety evaluation did not adversely affect plant safety or require changes to the plant technical specifications. Therefore, prior NRC approval was not required for implementation of the actions or changes identified within this evaluation.

10 CFR 50.59 EVALUATION PTN-ENG-SENS-01-057

Revision 2

UNIT: 3

APPROVAL DATE: 06/06/2002

TEMPORARY LOWERING OF UNIT 3 SFP LEVEL

Summary:

This evaluation was developed to examine the effects of securing the spent fuel cooling pumps and reducing the pool level by about one foot in order to perform maintenance on valve 3-798B in the filtration return header to the spent fuel pool (SFP). This evaluation addressed the effects of spent fuel handling accidents, SFP heatup rate, increased radiation levels resulting from lowered water (shielding) levels, and activation of system alarms. To reduce the potential for fuel handling accidents, all fuel movement and crane operation were suspended in accordance with Technical Specification 3/4.9.11. Considering the decay heat load in the SFP, it was estimated to take about 26 hours to heat the pool from 108 °F to 130 °F. This duration was determined to be sufficient to perform the required maintenance. Previous evaluations of reduced water levels have demonstrated that expected increases in radiation levels would be negligible. In order to preclude activation of the SFP alarms, pool temperature and level were required to be monitored on an hourly basis. A SFP temperature limit of 130 °F was established as an upper limit during the maintenance activity, at which time work would be secured and SFP cooling restored.

Revision 2 supports securing Unit 3 SFP cooling and lowering the Unit 3 SFP level approximately one foot in support of maintenance activities on isolation valve 3-821 in the 2-inch primary makeup water supply line to the Unit 3 SFP. Considering the decay heat load on the SFP, it was estimated to take about 31 hours to heat the pool from 104 °F to 130 °F. This allows sufficient time to perform the maintenance activities which were estimated to take less than two shifts to complete.

10 CFR 50.59 Evaluation:

This evaluation concluded that reducing the spent fuel pool level for maintenance on the isolation valve in the primary makeup water supply line to the Unit 3 SFP would not adversely impact plant operation and would not compromise the spent fuel handling accident analyses, provided that the actions and restrictions identified in the evaluation were observed. Consequently, the reduced pool water level and other actions identified in this 10 CFR 50.59 evaluation did not adversely affect plant safety or require changes to the plant technical specifications. Therefore, prior NRC approval was not required for implementation of the actions or changes identified within this evaluation.

10 CFR 50.59 EVALUATION PTN-ENG-SECS-02-025
Revision 0, Revision 1

UNIT : 4

APPROVAL DATE: 5/17/2002, Rev. 0
APPROVAL DATE: 5/18/2002, Rev. 1

TEMPORARY STORAGE OF EQUIPMENT IN UNIT 4 CONTAINMENT DURING ALL MODES OF OPERATION

Summary:

This evaluation addressed the acceptability of leaving a quantity of equipment and materials in the Unit 4 containment structure for one operating cycle. The subject items were associated with on-line replacement of the 4B control rod drive mechanism cooler fan motor. The specific items to be stored, and the storage locations within the Unit 4 containment, were specifically identified within the evaluation. The evaluation considered the potential for adverse seismic interactions with safety related equipment, the potential for additional hydrogen generation within containment during accidents, the impact on the containment free volume and heat sink analyses, the potential to obstruct flow to the containment sumps, and the impact on containment combustible loading. To ensure that the equipment and materials addressed in the evaluation were safely stored during plant operation, both generic and specific actions and restrictions were identified for implementation within the evaluation.

Revision 1 addressed the storage of some additional items inside containment associated with the maintenance activity.

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 evaluation concluded that the identified items could safely remain within containment during all modes of operation, provided that all of the restrictions and requirements identified within the evaluation were implemented. The evaluation further concluded that the identified restrictions and requirements would ensure that these activities would have no adverse effects on plant operation, and would not compromise the safety and licensing bases of the plant. Consequently, the requirements and restrictions identified in this 10 CFR 50.59 evaluation did not adversely affect plant safety or require changes to the plant technical specifications. Therefore, prior NRC approval was not required for implementation of the requirements or restrictions identified within this evaluation.

10 CFR 50.59 EVALUATION PTN-ENG-SECS-02-036
Revision 0

UNIT: 4

APPROVAL DATE: 07/23/2002

4D NORMAL CONTAINMENT COOLER SHIELDING, SCAFFOLDING AND TEMPORARY STORAGE OF ITEMS IN UNIT 4 CONTAINMENT DURING ALL MODES OF OPERATION

Summary:

This evaluation addressed the acceptability of leaving a quantity of equipment and materials in the Unit 4 containment structure for one operating cycle. The subject items were associated with on-line replacement of the 4D normal containment cooler fan motor bearing and shaft. The specific items to be stored, and the storage locations within the Unit 4 containment, were specifically identified within the evaluation. The evaluation considered the potential for adverse seismic interactions with safety related equipment, the potential for additional hydrogen generation within containment during accidents, the impact on the containment free volume and heat sink analyses, the potential to obstruct flow to the containment sumps, and the impact on containment combustible loading. To ensure that the equipment and materials addressed in the evaluation were safely stored during plant operation, both generic and specific actions and restrictions were identified for implementation within the evaluation.

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 evaluation concluded that the identified items can safely remain within containment during all modes of operation, provided that all of the restrictions and requirements identified within the evaluation were implemented. The evaluation further concluded that the identified restrictions and requirements would ensure that these activities would have no adverse effects on plant operation, and would not compromise the safety and licensing bases of the plant. Consequently, the requirements and restrictions identified in this 10 CFR 50.59 evaluation did not adversely affect plant safety or require changes to the plant technical specifications. Therefore, prior NRC approval was not required for implementation of the requirements or restrictions identified within this evaluation.

10 CFR 50.59 EVALUATION PTN-ENG-SENS-02-047
Revision 0

UNIT: 3 & 4

APPROVAL DATE: 09/27/2002

EVALUATION IN SUPPORT OF US-AS-IS DISPOSITION OF CONDITION REPORT 02-1599

Summary:

This 10 CFR 50.59 evaluation assesses a condition during normal plant operation where a reactor control operator (RCO) observed the 4B Core Exit Thermocouple (CET) subcooling margin reading nonconservatively high at 65 ^{0}F, which is outside of the expected range. The instrument was reset and reporting 36 ^{0}F which was within the expected range. The Qualified Safety Parameter Display System (QSPDS) has occasionally (frequency of 19-46 months) and randomly caused representative CET temperature to be calculated by the lowest CETs. This causes the CET subcooling value to be incorrectly calculated high by about 30 degrees (during normal plant operations). QSPDS 3A has experienced this problem once. The other QSPDS trains (3B, 4A) have not experienced this problem. Although this random occurrence during normal operation requires equipment reset to restore subcooling margin indication, discussions with Westinghouse indicate that this will not manifest itself as a failure during accident conditions. Specifically, during an event with a reactor trip, the anomaly should disappear and the equipment operate correctly due to CETs in the core trending to homogeneous values verses the comparatively diverse readings experienced in different regions during normal operation. Even if this were not the case, the anomaly would be acceptable based upon relative risk insignificance, the availability of alternate indications, relative impact during accident mitigation activities, and the operators ability to diagnose an incorrect reading.

10 CFR 50.59 Evaluation:

This 10 CFR 50.59 evaluation was prepared to accept the nonconforming condition described in Condition Report 04-1599 as an infrequent random display of a nonconservative subcooled margin value for a single channel of QSPDS. The reactor coolant system (RCS) subcooled margin monitor (SMM) function does not introduce the possibility of a change in the frequency of an accident because the QSPDS is not an initiator of any accident and no new credible failure modes are introduced which could impact the occurrence of an accident. The qualitative assessment provided in this evaluation demonstrated that the activity does not introduce the possibility of a change in the likelihood of a malfunction because the SMM temperature display is self-correcting during accident conditions. The random display of a nonconservative subcooled margin value for a single channel of QSPDS does not introduce the possibility of a change in the consequences of an accident because no equipment, system performance or operator actions are affected that could impact the response to design basis accidents. Therefore, the acceptance of the nonconforming condition does not have an adverse impact on plant safety and does not require a change to the plant technical specifications. Therefore prior NRC approval is not required.

10 CFR 50.59 EVALUATION PTN-ENG-SEMS-03-003
Revision 0

UNIT: 3 & 4

APPROVAL DATE: 02/26/2003

IMPLEMENTATION OF CORE OFFLOAD TO 72 HOURS

Summary:

The plant technical specifications prohibit the movement of irradiated fuel in the reactor core until the reactor has been subcritical for 100 hours. This evaluation determined that it is feasible from a spent fuel pool heat addition standpoint to begin transferring fuel immediately after 100 hours of core subcriticality provided fuel transfer is suspended when pool bulk temperature reaches 140°F. Suspending fuel transfer activities when the pool bulk temperature reaches 140°F prevents the bulk temperature from exceeding the regulatory commitment of limiting pool temperature to 150°F. The evaluation further determined that restricting the fuel transfer rate to six assemblies per hour or less would provide reasonable assurance that fuel transfer could continue uninterrupted without reaching heatup limits. However, the licensing basis core average decay heat rate of 50.5 Btu/second restricts offload start to no earlier than 116 hours with no power coastdown, 108 hours with coastdown if average power is maintained below 50% power for at least 48 hours prior to shutdown, and 90 hours with downpower if power is maintained at or below 60% power for at least 7 days prior to shutdown unless otherwise restricted by Technical Specifications. Based on the new analysis, no new plant restrictions were imposed to limit the minimum offload start time to 100 hours with power reduction performed prior to shutdown.

A UFSAR change package was provided as an attachment to this evaluation.

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 evaluation demonstrated that core offload could safely begin no earlier than 116 hours following subcriticality with no power coastdown, 108 hours with coastdown if average power is maintained below 50% power for at least 48 hours prior to shutdown, or 90 hours with downpower if power is maintained below 60% power for at least 7 days prior to shutdown unless otherwise restricted by Technical Specifications. However, plant technical specifications prohibited the movement of irradiated fuel in the reactor core until the reactor has been subcritical for 100 hours. The fuel transfer restrictions ensured that fuel cladding temperature remained within analyzed limits and did not compromise fuel clad integrity. The earlier offload start times and reduced offload rate did not introduce new failure modes because the equipment and practices employed in fuel handing remain unchanged. The evaluation concluded that the change in offload time did not affect plant safety or operation or require a change to the plant technical specifications. Therefore, prior NRC approval was not required to implement the revised offload times or offload rates.

10 CFR 50.59 EVALUATION PTN-ENG-SEFJ-03-007

Revision 1

UNIT: 3 & 4

APPROVAL DATE: 08/28/2003

TURKEY POINT FSAR AND DBD CHANGE PACKAGES FOR THE REANALYSIS OF THE LOSS OF NORMAL FEEDWATER AND LOSS OF NON-EMERGENCY POWER FOR MINIMUM STEAM GENERATOR TUBE PLUGGING

Summary:

This evaluation reanalyzes the Loss of Normal Feedwater (LONF) and Loss of Non-Emergency AC Power to Plant Auxiliaries (LOAC) design basis events to address a non-conservative analysis modeling assumption identified by Westinghouse in Safety Advisory Letter NSAL-02-1. The assumption involved modeling the steam generator using the maximum steam generator tube plugging (SGTP) levels for the LONF and LOAC events. LONF/LOAC analysis assumptions are selected to conservatively demonstrate that system overpressure, DNB, and pressurizer overfill acceptance criteria are met. To conservatively reduce secondary-side heat removal, maximum SGTP levels have been historically modeled in the analysis. An increased maximum SGTP level results in a reduced heat transfer area and a larger primary-side heatup. Hence, it was assumed that these conditions would lead to a larger reactor coolant swell resulting in more limiting pressurizer fill conditions. However, an investigation into effects of SGTP conditions identified a non-conservative assumption with respect to the criterion of precluding the pressurizer filling events. When minimum or no SGTP is assumed, a larger reactor coolant system (RCS) fluid volume exists with the capacity for more heat removal. Though more heat removal capability with minimum SGTP reduces the rate of reactor coolant thermal expansion during heatup, this benefit with respect to pressurizer overfill could be offset by the larger initial RCS inventory available to expand. These competing effects are dependent on the transient conditions and auxiliary feedwater (AFW) assumptions used in the safety analysis. The results of a new analysis with minimum or no SGTP show that all of the applicable safety acceptance criteria, especially RCS overpressure and no pressurizer filling requirements, continue to be met. LONF/LOAC UFSAR and Design Basis Document (DBD) change packages were provided with this 10 CFR 50.59 evaluation to reflect the changes made to the accident analyses.

10 CFR 50.59 Evaluation:

The changes to the LONF/LOAC analysis are all input changes (AFW delay time of 95 seconds and minimum or no SGTP) and are not changes to the methodology to analyze the events, which remain unchanged. The reanalysis of the LONF with AFW delay time of 95 seconds and minimum or no SGTP and LOAC with minimum or no SGTP shows that all applicable safety acceptance criteria, specifically the overpressure and no pressurizer filling, continue to be met. That is, the RCS and main steam system pressures do not exceed 110% of design pressure. Additionally, the pressurizer does not reach a water solid condition, ensuring that the events do not progress from ANS Condition II events to more severe events. The review of the reanalysis of the LONF and LOAC events concluded that the reanalysis and the proposed changes to the UFSAR and DBD do not affect the technical specifications and do not require a license amendment. Therefore, prior NRC approval was not required for the implementation of the UFSAR and DBD changes.

10 CFR 50.59 EVALUATION PTN-ENG-SEMS-03-011

UNIT: 4

APPROVAL DATE: 02/13/2002

ALTERNATE THERMAL RELIEF FOR THE CVCS REGENERATIVE HEAT EXCHANGER

Summary:

This evaluation assessed the impact on plant safety and operation of isolating thermal relief valve RV 4-311 (located upstream of the Chemical & Volume Control System (CVCS) regenerative heat exchanger (RHX)) on line and temporarily utilizing CV-4-311 (auxiliary spray flow line isolation valve) to provide the relief function while RV-4-311 was non-functional. Isolation of RV-4-311 was required because it was leaking past its seat during plant operation causing pressurizer relief tank (PRT) level to fluctuate. Increased in-leakage to the PRT and temperature measurements concluded that the most probable source of the in-leakage was through RV-4-311. The purpose of this evaluation was to provide the basis to isolate the RV-4-311 relief path and transfer the thermal relief function temporarily to downstream relief valve CV-4-311 to satisfactorily protect the system from thermal overpressurization concerns. The evaluation assessed the effect of temporarily using CV-4-311 as the relief device in place of RV-4-311 on regenerative heat exchanger operability, piping and fitting operability, valve operability, relief valve code compliance, valve closure assist device structural qualification, Appendix R modifications to CV-4-311, Generic Letter 96-06, in-service test implications, and foreign material exclusion considerations.

10 CFR 50.59 Evaluation:

This evaluation assessed the compensatory action of using CV-4-311 to provide requisite thermal overpressure protection for the regenerative heat exchanger in place of RV-4-311 while the system is aligned to the reactor coolant system (RCS). The charging system is not an accident initiator in any accidents previously evaluated. The isolation of the discharge flow path for RV-4-311 could cause higher internal pressure accumulation in the affected piping segment prior to relief through CV-4-311. However, adequate thermal relief protection would be maintained by CV-4-311. The proposed change does not alter the pressure retaining characteristics of any component in the charging system flow path. Failure probabilities have been evaluated for the proposed use of CV-4-311 for thermal overpressure protection in lieu of RV-4-311 and the increase in pressure boundary failure probability was shown to be less than minimal. The isolation of the RV-4-311 thermal relief valve discharge path does not alter the flow delivery functions of the charging system or compromise the pressure integrity functions of the CVCS or the RCS; thus, no increase in core damage was postulated and the proposed configuration does not create any unanalyzed release paths. The evaluation demonstrated that the temporary charging system alignment change required to isolate the leakage from the CVCS to the pressurizer relief tank did not introduce any new failure modes for the CVCS or RCS, nor adversely affect operation of any safety related equipment. No design or operating limits were impacted and the activity did not result in a design basis limit or a fission product barrier being exceeded or altered. Therefore, this activity does not affect plant safety or require a change to the plant technical specifications. Therefore, NRC approval was not required prior to implementation.

10 CFR 50.59 EVALUATION PTN-ENG-SEMS-03-015
Revision 1, Revision 0

UNIT:	3 & 4
APPROVAL DATE:	10/04/2003, Rev. 1
APPROVAL DATE:	03/04/2003, Rev. 0

DISCHARGE OF REACTOR VESSEL HEAD WASH DOWN WATER TO REACTOR CAVITY DURING MODE 6

Summary:

This 10 CFR 50.59 evaluation examined the controls, procedures, and processes used in the maintenance task to conduct an under the reactor vessel head wash in preparation for the Unit 3 Cycle 20 remote ultrasonic test (UT) examination of the reactor vessel closure head penetrations. The purpose of the wash down was to provide better UT probe life and signal. The wash was conducted using clean unborated demineralized water (from the primary water system) through a portable high-pressure spray unit. The inside area of the reactor head stand was sealed (non-permanent coating) creating a collection pool for the wastewater which provided control over the amount and rate of discharge to the flooded reactor cavity. The wastewater was transferred to the flooded reactor cavity using a submersible effluent pump which discharged to the suction of the lower reactor cavity filtration system located in the deep end of the reactor cavity to maximize mixing. The controls established minimized the potential for the introduction of the unborated wastewater into the refueling cavity to cause a dilution in the reactor coolant system (RCS) and thereby introduce a positive reactivity addition to the fuel in the reactor vessel.

Revision 1 to this evaluation was expanded to include the Unit 4 maintenance task to conduct an under the reactor vessel head washdown in preparation for the Unit 4 Cycle 21 remote UT examination of the reactor vessel closure head penetration. With the exception of the Unit designation, all calculations and assumptions were valid for applicability to Unit 4.

10 CFR 50.59 Evaluation:

The 10 CFR 50.59 evaluation assessed the dilution event caused by the introduction of unborated water into the RCS during the reactor vessel head wash. The evaluation conservatively assumed that 1100 gallons of water would be used in the head wash down. This was conservatively based on assuming the high pressure spray unit used approximately 5 gpm of water and was used for two hours (head wash was expected to take less than one hour). The amount of water would be 5 gpm times 120 minutes which equals 600 gallons. Based upon an initial refueling cavity pool level of 57 ft. and a boron concentration of 1950 ppm, the addition of 1100 gallons of unborated water would lower the initial boron concentration by less than 10 ppm. The actual change to the boron concentration would be considerably less. The boron concentration would have to be diluted to approximately 1400 ppm before the reactor would go critical. Therefore, the likelihood of an uncontrolled boron dilution event from the proposed maintenance activity was considered extremely small. The failure modes for the reactor vessel closure head wash down and wastewater transfer activities were reviewed and it was determined that the affect on boron dilution is bounded by the boron dilution assumptions of the evaluation. The 10 CFR 50.59 evaluation confirmed that the proposed maintenance activities did not adversely affect plant safety or require a change to the plant technical specifications provided the actions and restrictions identified in this evaluation were observed. Therefore, prior NRC approval was not required for implementation of the actions identified within the evaluation.

10 CFR 50.59 EVALUATION PTN-ENG-SEFS-03-021

UNIT: 3

APPROVAL DATE: 03/20/2003

EVALUATION OF HIGHER SILICA LIMITS IN RCS
TURKEY POINT UNIT 3 CYCLE 20

Summary:

The purpose of this evaluation was to assess plant operation with reactor coolant system (RCS) silica levels of <3 ppm for 30 days after Unit 3 Cycle 20 startup (Mode 2), compared to the then current limit of <1 ppm. With the continued degradation of the Boraflex material used in the spent fuel pool (SFP) racks and the corresponding increased silica level in the SFP and refueling water storage tank (RWST), the time to reduce the silica level in the RCS becomes an operational concern at startup following refueling. This condition results from mixing of reactor coolant with SFP and RWST water during refueling operations. The current silica limit in the RCS during power operation is 1 ppm. This evaluation considered the impact of power operation at higher silica concentrations on the fuel, RCS components and auxiliary systems. This evaluation provides guidelines on silica levels and impurity limits such that fuel performance and RCS and auxiliary system components would not be affected.

10 CFR 50.59 Evaluation:

This evaluation determined that the current diagnostic limit of <1 ppm silica may be relaxed to <3 ppm for up to 30 days of power operation after initial criticality of Unit 3 Cycle 20. Operation with silica < 3 ppm for 30 days is in accordance with fuel vendor guidelines for silica divergence and is consistent with EPRI's recommended limits provided that aluminum (Al), calcium (Ca), and magnesium (Mg) are controlled within fuel vendor recommended limits. The potential adverse effect of silica on fuel cladding surface was assessed. It was determined that the current thermodynamic models and experience base justify the proposed 3 ppm diagnostic limit for RCS silica, based on achieving makeup water impurity limits for cations (Al, Ca, Mg) per fuel vendor guidelines. The fuel failure mode analysis, including UFSAR accident analyses, are not affected by the increased silica limits. The evaluation shows that the 3 ppm silica level is still low enough not to cause an increase in precipitation rates of silicates, therefore there is no potential to increase the cladding oxidation rate nor increase the probability of fuel failure. The potential impact of increasing from 1 ppm to 3 ppm silica on reactor coolant pump seals wear rate was assessed and determined to be acceptable. There is no indication that the increased silica levels would result in an increase in the probability of inter-granular stress corrosion cracking of alloy 600 material present in the RCS. The presence of higher silica concentrations in a chemical and volume control system (CVCS) ion exchanger would not adversely affect the corrosion rate of RCS components. As a result, the RCS continues to present a robust barrier to fission product release and no design limits described in the UFSAR are challenged. The higher silica levels will not result in an increase in crud formation provided that Al, Ca, and Mg impurities are limited as discussed above. Therefore, the increased silica levels would not adversely affect the functionality of the ion exchangers which will continue to scavenge fission products and other large ions present in CVCS effluent. Since this activity did not impact safe plant operation or require a change to the plant technical specifications, prior NRC approval was not required.

10 CFR 50.59 EVALUATION PTN-ENG-SEMS-03-035
Revision 2

UNIT: 3 & 4

APPROVAL DATE: 08/19/2003

EVALUATION FOR CONTROL ROOM TRACER GAS TESTING TO MEASURE UNFILTERED INLEAKAGE

Summary:

The Nuclear Regulatory Commission (NRC) issued Generic Letter 2003-01 requiring plants to perform tests to measure the quantity of unfiltered inleakage into the control room. This 10 CFR 50.59 evaluation of a tracer gas injection test was performed to ensure continued operability of the Control Room Emergency Ventilation System (CREVS) during setup, performance, and demobilization of the test.

Two tests were performed with the injection of a tracer gas, Sulfur Hexafluoride (SF_6), into the control room envelope. One test measured the filtered makeup through the emergency intake. The second measured unfiltered inleakage to the control room. The tests were performed using procedure TP 03-017 in accordance with the guidance contained in ASTM E 741. SF_6 is a non-toxic, chemically inert, colorless, odorless gas. SF_6 was shown not to have any adverse effects on control room personnel, control room functions and indications, or CREVS equipment in the concentrations used in this test.

10 CFR 50.59 Evaluation:

This evaluation demonstrated that setup, performance and demobilization of the tracer gas test would not affect CREVS operability. The assessment demonstrated that SF_6 has no affect on CREVS or control room personnel or equipment including the charcoal filters, fans, ductwork, air handling units and control room instrumentation. A failure modes and effects analysis determined that no new failure modes that could impact nuclear safety, and the probability of occurrence and consequences of previously analyzed failures are not increased. The control room operator dose is calculated for the loss of coolant accident and the fuel handling accident in the UFSAR. Per the plant restrictions specified in the evaluation, no fuel movement was permitted during the test and therefore a fuel handling accident could not occur. During the tracer gas test, the design basis of the operating CREVS was maintained. The tracer gas test does not depart from methodologies described in the UFSAR since the test requires the CREVS to be aligned essentially the same as during normal surveillance operation. This evaluation concluded that the tracer gas test could be performed in accordance to with TP 03-017 provided that certain actions and restrictions were adhered to. The test conditions described in the evaluation do not adversely effect plant safety or require a change to the plant technical specifications. Therefore, prior NRC approval was not required for implementation of the actions identified within the evaluation.

10 CFR 50.59 EVALUATION PTN-ENG-SENS-03-040

UNIT: 4

APPROVAL DATE: 08/24/2003

TEMPORARY LOWERING OF SPENT FUEL POOL WATER LEVEL FOR MAINTENANCE ACTIVITIES

Summary:

This evaluation was developed to examine the effects of securing the spent fuel cooling pumps and reducing the pool level by about 1-foot in support of coincidental maintenance activities on the demineralized water supply to Spent Fuel Pool (SFP) isolation valve (4-821), and on valve 4-798B in the filtration return header to the SFP. This evaluation examined the effects of spent fuel handling accidents, spent fuel heatup rates, increased radiation levels resulting from lowered water (shielding) levels, and activation of system alarms. To reduce the potential for fuel handling accidents, all fuel movement and crane operation were suspended in accordance with Technical Specification 3/4.9.11. The SFP has been evaluated for elevated temperatures. Based on heatup rates of July 31, 2003 from the Plant Curve Book, pool heatup from 104 °F to 130 °F was estimated to take 16 hours, which was sufficient to perform the required maintenance. Actual experience, as recorded from actual temperatures during similar draindown tasks on Units 3 and 4 SFPs, indicate that the Curve Book heatup rate is typically overly conservative. Using a more realistic heatup rate indicates that it should take approximately 18.5 hours to reach 130 °F, which was more than adequate time to perform the required maintenance. Previous evaluations of reduced water levels have demonstrated that expected increases in radiation levels would be negligible. In order to preclude activation of the SFP alarms, pool temperature and level were required to be monitored on an hourly basis. A SFP temperature limit of 130 °F was established as an upper limit during the maintenance activity, at which time work would be secured and SFP cooling restored.

10 CFR 50.59 Evaluation:

This evaluation concluded that reducing the spent fuel pool level for coincident maintenance on the demineralized water supply to SFP isolation valve and on the filtration return header to SFP valve would not adversely impact plant operation, and would not compromise the spent fuel handling accident analyses provided that the actions and restrictions identified in the evaluation were observed. Consequently, the reduced pool water level and other actions identified in this evaluation did not adversely affect plant safety or require changes to the plant technical specifications. Therefore, prior NRC approval was not required for implementation of the actions or changes identified within this evaluation.

SECTION 3

RELOAD SAFETY EVALUATIONS

PLANT CHANGE/MODIFICATION 02-086
Revision 1

UNIT: 3

TURN OVER DATE: 09/23/2003

TURKEY POINT UNIT 3 CYCLE 20 RELOAD DESIGN

Summary:

This Engineering Package provided the reload core design for the Turkey Point Unit 3 Cycle 20 reload. The primary design change to the core for Cycle 20 was the replacement of 60 irradiated assemblies with 60 fresh Debris Resistant Fuel Assemblies (DRFA). Similar to past reloads, these fresh Debris Resistant Fuel Assemblies (DRFA), with a nominal fuel enrichment of either 4.0 w/o or 4.4 w/o, all contain a nominal 6-inch axial blanket of natural UO_2 pellets at both the top and bottom of the fuel stack. No Wet Annular Burnable Absorbers (WABA) were used in this reload consistent with the current core design practice. The maximum fuel enrichments for the DRFA used in Cycle 20, including the 0.05 w/o fabrication uncertainty, is 4.45 w/o which is less than the plant technical specification limit of 4.50 w/o.

There are no mechanical design changes to the fresh fuel assemblies to be loaded into Unit 3 for Cycle 20 with respect to the fresh fuel loaded in Cycle 19.

Cross core fuel bundle shuffles were utilized in the Cycle 20 loading pattern to minimize potential power asymmetries. The fuel was arranged in a low leakage pattern with no significant differences between the Cycle 19 and Cycle 20 patterns.

10 CFR 50.59 Evaluation:

The Unit 3 Cycle 20 reload core design was evaluated by FPL and by the fuel supplier, Westinghouse Electric Corporation. The Cycle 20 reload core design met all applicable design criteria, appropriate licensing bases, and the requirements of plant technical specifications. The Cycle 20 core reload did not have any adverse effect on plant safety or plant operations or require changes to plant technical specifications. Therefore, prior NRC approval was not required for implementation.

PLANT CHANGE/MODIFICATION 03-046

UNIT: 4

TURN OVER DATE: 03/01/2004

TURKEY POINT UNIT 4 CYCLE 21 RELOAD DESIGN

Summary:

This Engineering Package provided the reload core design for the Turkey Point Unit 4 Cycle 21 reload. The primary design change to the core for Cycle 21 was the replacement of 56 irradiated assemblies with 56 fresh Debris Resistant Fuel Assemblies (DRFA). Similar to past reloads, these fresh Debris Resistant Fuel Assemblies (DRFA), with nominal fuel enrichments of either 4.0 w/o or 4.4 w/o, all contain a nominal 6-inch axial blanket of natural UO_2 pellets at both the top and bottom of the fuel stack. No Wet Annular Burnable Absorbers (WABA) were used in this reload consistent with the current core design practice. The maximum fuel enrichments for the DRFA used in Cycle 21, including the 0.05 w/o fabrication uncertainty, is 4.45 w/o which is less than the plant technical specification limit of 4.50 w/o.

There are no mechanical design changes to the fresh fuel assemblies to be loaded into Unit 4 for Cycle 21 with respect to the fresh fuel load in Unit 3 Cycle 20.

Cross core fuel bundle shuffles were utilized in the Cycle 21 loading pattern to minimize potential power asymmetries. The fuel was arranged in a low leakage pattern.

10 CFR 50.59 Evaluation:

The Unit 4 Cycle 21 reload core design was evaluated by FPL and by the fuel supplier, Westinghouse Electric Corporation. The Cycle 21 reload core design met all applicable design criteria, appropriate licensing bases, and the requirements of plant technical specifications. The minor design modifications to fuel assemblies in this reload did not affect applicable design criteria and did not increase the radiological consequences of any accident previously evaluated in the UFSAR. These changes had no impact on fuel rod performance, dimensional stability or core operating limits. The Cycle 21 core reload did not have any adverse effect on plant safety or plant operations or require changes to plant technical specifications. Therefore, prior NRC approval was not required for implementation.

SECTION 4

REPORT OF POWER OPERATED RELIEF VALVE (PORV) ACTUATIONS

ANNUAL REPORT OF SAFETY AND RELIEF VALVE CHALLENGES

By letter dated June 18, 1980 (L-80-186) Florida Power and Light Company stated their intent to comply with the requirements of Item II.K.3.3 of Enclosure 3 to the Commissioner's letter of May 7, 1980 (Five Additional TMI-2 Related Requirements for Operating Reactors). Pursuant to these requirements, a summary of the power operated relief valve (PORV) actuations that have occurred at Turkey Point Units 3 and 4 during this reporting period is provided below:

Unit 3

No PORV actuations have occurred on Turkey Point Unit 3 between April 7, 2002 and November 5, 2003.

Unit 4

No PORV actuations have occurred on Turkey Point Unit 4 between April 7, 2002 and November 5, 2003.

SECTION 5

STEAM GENERATOR TUBE INSPECTIONS FOR TURKEY POINT

Page 1 of 1

FORM NIS-BB OWNERS' DATA REPORT FOR EDDY CURRENT EXAMINATION RESULTS
As required by the provisions of the ASME CODE RULES

EDDY CURRENT EXAMINATION RESULTS

PLANT: Turkey Point Unit 3

EXAMINATION DATE: March 9, 2003 through March 13, 2003

STEAM GENERATOR	TOTAL TUBES INSPECTED	TOTAL TUBES 20%-39%	TOTAL TUBES ≥40%, PIT & VOL	TUBES PREVENTIVELY PLUGGED (PTP)	TUBES PLUGGED THIS OUTAGE	TOTAL PLUGGED TUBES IN S/G
3E210A (Bobbin)	3168	6(1)	0	0	0	See RPC
3E210B (Bobbin)	3147	6(1)	0	1(4)	1(4)	See RPC
3E210C (Bobbin)	3161	26(1)	0	0	0	See RPC
3E210A (RPC)	3397(5)	2(2)	0	1(3)	1(3)	47
3E210B (RPC)	3307(5)	0	0	1(4)	1(4)	69
3E210C (RPC)	3288(5)	0	0	0	0	53

LOCATION OF INDICATIONS
(20% - 100%, PIT & VOL)

STEAM GENERATOR	AVB Bars	Tube Supports 1 thru 6 C/L	Tube Supports 1 thru 6 H/L	Freespan 6H thru 6C UBEND	Top of Tubesheet to #1 Support C/L	Top of Tubesheet to #1 Support H/L	Total Indications 20%-39%	Total Indications ≥40%, PIT & VOL
3E210A (Bobbin)	6(1)	0	0	0	0	0	6	0
3E210B (Bobbin)	13(1)	0	0	0	0	0	13	0
3E210C (Bobbin)	40(1)	0	0	0	0	0	40	0
3E210A (RPC)	0	0	0	1(3)	0	1(2)	2	0
3E210B (RPC)	0	0	0	0	0	0	0	0
3E210C (RPC)	0	0	0	0	0	0	0	0

Remarks:
(1) Mechanical wear damage at anti-vibration bars (AVB) was depth sized using qualified bobbin coil sizing technique.
(2) Mechanical wear damage at the top of tubesheet was depth sized using qualified Plus Point RP coil sizing technique. (R16 C4 in SG 3A)
(3) One tube in 3A (R21 C38) was preventatively plugged due to a manufacturing indication (SVI – Single Volumetric Indication) in the U-bend region. This indication was determined to be present since the preservice inspection and has not exhibited any evidence of change.
(4) Two tubes in 3B were preventively plugged. One due to mechanical wear (35% through wall) at an anti vibration bar in the u-bend and one tube due to a restriction in the u-bend to a plus point examination.
(5) Includes tubes in the hot leg dent, low row U-bend, special interest (SI) and hot leg TTS expansion transition programs.

(SG 3A)

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 3 Component: S/G A

EOC19 20-39% Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	EXT	UTIL 1	UTIL 2	CAL #	LEG	PROBE
16	4	0.24	120	2	TWD	29	TSH	+1.36	TSH	TSH	0.71	WAR	31	HOT	720PP
21	38	0.24	91	3	SVI		AV2	+11.25	AV2	AV2	0.20	25	42	HOT	680IP
28	59	0.66	85	P 2	TWD	25	AV2	-0.33	TEH	TEC			16	COLD	720UL
30	52	0.50	85	P 2	TWD	21	AV3	-0.19	TEH	TEC			15	COLD	720UL
31	44	0.48	137	P 2	TWD	22	AV3	+0.00	TEH	TEC			12	COLD	720UL
33	15	0.62	134	P 2	TWD	20	AV3	-0.00	TEH	TEC			3	COLD	720UL
37	47	0.88	66	P 2	TWD	30	AV3	+0.00	TEH	TEC			15	COLD	720UL
38	65	0.48	33	P 2	TWD	21	AV3	+0.05	TEH	TEC			17	COLD	720UL

Total Tubes : 8
Total Records: 8

Attachment 2 (SG 3B)

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 3 Component: S/G B

EOC19 20-39% Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	EXT	UTIL 1	UTIL 2	CAL #	LEG	PROBE
30	42	0.57	43	P 2	TWD	21	AV2	+0.07	TEH	TEC			6	COLD	720UL
		0.94	72	P 2	TWD	29	AV3	+0.15	TEH	TEC			6	COLD	720UL
		0.69	43	P 2	TWD	24	AV4	+0.00	TEH	TEC			6	COLD	720UL
32	34	0.52	66	P 2	TWD	24	AV4	-0.12	TEH	TEC			7	COLD	720UL
		1.02	54	P 2	TWD	35	AV2	-0.20	TEH	TEC			7	COLD	720UL
		0.99	72	P 2	TWD	35	AV1	+0.00	TEH	TEC			7	COLD	720UL
		0.51	42	P 2	TWD	24	AV3	-0.72	TEH	TEC			7	COLD	720UL
		0.97	75	P 2	TWD	34	AV3	+0.55	TEH	TEC			7	COLD	720UL
34	31	0.69	55	P 2	TWD	23	AV3	+0.39	TEH	TEC			8	COLD	720UL
34	53	1.03	83	P 2	TWD	28	AV2	-0.76	TEH	TEC			18	COLD	720UL
		0.66	132	P 2	TWD	21	AV1	+0.02	TEH	TEC			18	COLD	720UL
35	48	0.69	129	P 2	TWD	21	AV3	+0.11	TEH	TEC			18	COLD	720UL
45	46	0.53	42	P 2	TWD	20	AV2	+0.07	TEH	TEC			6	COLD	720UL

Total Tubes : 6
Total Records: 13

(SG 3C)

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 3 Component: S/G C

EOC19 20-39% Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	EXT	UTIL 1	UTIL 2	CAL #	LEG	PROBE
21	38	0.46	62	P 2	TWD	24	AV3	-0.13	TEH	TEC			8	COLD	720UL
		0.46	32	P 2	TWD	24	AV2	+0.06	TEH	TEC			8	COLD	720UL
21	62	0.29	130	P 2	TWD	20	AV2	-0.09	TEH	TEC			11	COLD	720UL
23	45	0.47	149	P 2	TWD	23	AV3	+0.16	TEH	TEC			7	COLD	720UL
24	59	0.39	63	P 2	TWD	24	AV1	+0.00	TEH	TEC			11	COLD	720UL
		0.36	33	P 2	TWD	23	AV2	-0.11	TEH	TEC			11	COLD	720UL
24	63	0.51	32	P 2	TWD	24	AV3	+0.22	TEH	TEC			12	COLD	720UL
25	62	0.44	69	P 2	TWD	26	AV2	-0.14	TEH	TEC			11	COLD	720UL
		0.41	158	P 2	TWD	25	AV3	-0.02	TEH	TEC			11	COLD	720UL
26	58	0.41	48	P 2	TWD	20	AV1	+0.04	TEH	TEC			12	COLD	720UL
		0.70	135	P 2	TWD	29	AV2	+0.17	TEH	TEC			12	COLD	720UL
28	48	0.89	87	P 2	TWD	34	AV2	+0.15	TEH	TEC			10	COLD	720UL
30	30	0.38	40	P 2	TWD	20	AV4	+0.07	TEH	TEC			5	COLD	720UL
30	31	0.49	42	P 2	TWD	24	AV3	-0.13	TEH	TEC			6	COLD	720UL
		0.47	124	P 2	TWD	24	AV2	-0.04	TEH	TEC			6	COLD	720UL
		0.50	48	P 2	TWD	25	AV1	-0.37	TEH	TEC			6	COLD	720UL
30	61	0.66	81	P 2	TWD	28	AV2	+0.09	TEH	TEC			12	COLD	720UL
33	31	0.42	147	P 2	TWD	22	AV3	-0.13	TEH	TEC			6	COLD	720UL
33	32	0.37	68	P 2	TWD	20	AV3	+0.14	TEH	TEC			5	COLD	720UL
33	43	0.60	28	P 2	TWD	28	AV3	-0.17	TEH	TEC			6	COLD	720UL
		0.42	135	P 2	TWD	22	AV2	-0.08	TEH	TEC			6	COLD	720UL
34	31	0.78	129	P 2	TWD	32	AV3	-0.15	TEH	TEC			6	COLD	720UL
		0.59	83	P 2	TWD	27	AV2	-0.04	TEH	TEC			6	COLD	720UL
34	41	0.64	108	P 2	TWD	29	AV4	-0.15	TEH	TEC			6	COLD	720UL
		0.72	105	P 2	TWD	31	AV3	-0.15	TEH	TEC			6	COLD	720UL
		0.72	113	P 2	TWD	31	AV2	-0.06	TEH	TEC			6	COLD	720UL
		0.72	130	P 2	TWD	31	AV1	+0.10	TEH	TEC			6	COLD	720UL
34	44	0.51	47	P 2	TWD	25	AV3	+0.02	TEH	TEC			5	COLD	720UL
35	35	0.38	70	P 2	TWD	21	AV3	+0.00	TEH	TEC			6	COLD	720UL
35	36	0.52	41	P 2	TWD	25	AV2	+0.00	TEH	TEC			5	COLD	720UL
		0.56	88	P 2	TWD	26	AV3	+0.02	TEH	TEC			5	COLD	720UL
35	49	0.51	43	P 2	TWD	24	AV4	+0.02	TEH	TEC			9	COLD	720UL
37	28	0.43	36	P 2	TWD	22	AV4	-0.14	TEH	TEC			5	COLD	720UL
38	61	0.39	125	P 2	TWD	20	AV2	+0.11	TEH	TEC			12	COLD	720UL
38	65	0.53	124	P 2	TWD	29	AV2	-0.07	TEH	TEC			11	COLD	720UL
		0.37	112	P 2	TWD	24	AV3	+0.25	TEH	TEC			11	COLD	720UL
		0.69	58	P 2	TWD	33	AV4	-0.07	TEH	TEC			11	COLD	720UL
38	71	0.60	138	P 2	TWD	28	AV3	+0.00	TEH	TEC			15	COLD	720UL
40	25	0.36	134	P 2	TWD	20	AV2	-0.11	TEH	TEC			4	COLD	720UL
40	55	0.43	123	P 2	TWD	23	AV3	-0.09	TEH	TEC			10	COLD	720UL

Total Tubes : 26
Total Records: 40

(SG 3A)

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 3 Component: S/G A

EOC19 40-100%,VOL,PIT,PTP Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	EXT	UTIL 1	UTIL 2	CAL #	LEG	PROBE
21	38				PTP			AV2	AV2			30	HOT	6801P

Total Tubes : 1
Total Records: 1

(SG 3B)

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 3 Component: S/G B

EOC19 40-100%,VOL,PIT,PTP Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	EXT	UTIL 1	UTIL 2	CAL #	LEG	PROBE
1	86				PTP			06H	06C			27	HOT	6801P
32	34				PTP			TEH	TEC			7	COLD	720UL

Total Tubes : 2
Total Records: 2

(SG 3C)

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 3 Component: S/G C

EOC19 40-100%,VOL,PIT,PTP Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	EXT	UTIL 1	UTIL 2	CAL #	LEG	PROBE

Total Tubes : 0
Total Records: 0

[illegible] OWNER'S DATA REPORT [illegible] CURRENT EXAMINATION RESULTS
As required by the provisions of the ASME CODE RULES

[illegible] CURRENT EXAMINATION RESULTS

PLANT: Turkey Point Unit 4
EXAMINATION DATE: October 15, 2003 to October 20, 2003

STEAM GENERATOR	TOTAL TUBES INSPECTED	TOTAL TUBES 20%-39%	TOTAL TUBES ≥40%, PIT & VOL	TUBES PREVENTIVELY PLUGGED (PTP)	TUBES PLUGGED THIS OUTAGE	TOTAL PLUGGED TUBES IN S/G
4E210A (Bobbin)	**3195**	**1** (1)	0	0	0	See RPC
4E210B (Bobbin)	**3201**	**0**	0	0	0	See RPC
4E210C (Bobbin)	**3203**	**2** (1)	0	0	0	See RPC
4E210A (RPC)	**3195**(4)	0	**2**	**2**	**4**	23
4E210B (RPC)	**3201** (4)	0	0	0	0	13
4E210C (RPC)	**3203**(4)	0	0	0	0	11

LOCATION OF INDICATIONS
(20% - 100%, PIT & VOL, WAR,PLP, SVI)

STEAM GENERATOR	AVB Bars	Tube Supports 1 thru 6 C/L	Tube Supports 1 thru 6 H/L	Freespan 6H thru 6C UBEND	Top of Tubesheet to #1 Support C/L	Top of Tubesheet to #1 Support H/L	Total Indications 20%-39%	Total Indications ≥40%, PIT & VOL
4E210A (Bobbin)	1	0	0	0	0	0	1	0
4E210B (Bobbin)	0	0	0	0	0	0	0	0
4E210C (Bobbin)	2	0	0	0	0	0	2	0
4E210A (RPC)	0	0	0	0	1 (2)	3 (3) (5)	0	4
4E210B (RPC)	0	0	0	0	0	0	0	0
4E210C (RPC)	0	0	0	0	0	0	0	0

LOCATION OF INDICATIONS
(1% - 19%) Bobbin Probe Only

STEAM GENERATOR	AVB Bars	Tube Supports 1 thru 6 C/L	Tube Supports 1 thru 6 H/L	Freespan 6H thru 6C UBEND	Top of Tubesheet to #1 Support C/L	Top of Tubesheet to #1 Support H/L	Total Indications 1%-19%	Total Indications 1%-39% Left in Service
4E210A (Bobbin)	6	0	1(6)	0	0	0	7	8
4E210B (Bobbin)	12	1(6)	0	0	0	0	13	13
4E210C (Bobbin)	9	0	0	0	0	0	9	11

Remarks:
1. Mechanical wear damage at anti-vibration bars (AVB) was depth sized using qualified bobbin coil sizing technique.
2. One tube in 4A was preventatively plugged due to VOL type signal at TSC +12.5 inches.
3. One tube in 4A was preventatively plugged due to minor wear associated with a possible loose part (PLP) at the hot leg baffle plate
4. Includes tubes in the dent, low row U-bend and hot leg TTS expansion transition programs.
5. Two tubes in 4A were reported as Pit-like (PIT) indications at BAH, were called single volumetric indications (SVI) and were plugged.
6. Indications detected at broached supports by bobbin coil and confirmed to be low level wear (WAR) by rotating coil

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 4
Component: S/G A

All Tubes with Pluggable Indications in Steam Generator "A"

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	UTIL1	CAL #	LEG	PROBE
3	1	0.22	71	P 4	SVI	PIT	BAH -0.38	BAH BAH	23	44	HOT	720PP
23	10				PLP	PTP	BAH +0.34	BAH BAH		44	HOT	720PP
40	28	0.31	102	P 4	SVI	PIT	BAH -0.22	BAH BAH	25	44	HOT	720PP
45	45	0.56	112	1	VOL		TSC +12.15	TSC BAC	24	44	COLD	720PP
						PTP		TSC BAC		44	COLD	720PP

Total Tubes : 4
Total Records: 5

NO TUBES WERE PLUGGED IN STEAM GENERATOR "B"

NO TUBES WERE PLUGGED IN STEAM GENERATOR "C"

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 4
Component: S/G A

Tubes with 1-19% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT		CAL #	LEG	PROBE
4	58	0.10	0	P5	WAR	7	02H	+0.51	02H	02H	44	HOT	720PP
26	20	0.19	101	P 2	TWD	6	AV1	+0.00	TEH	TEC	25	COLD	720UL
32	74	0.37	46	P 2	TWD	13	AV1	-0.02	TEH	TEC	1	COLD	720UL
33	72	0.41	118	P 2	TWD	18	AV1	+0.03	TEH	TEC	2	COLD	720UL
37	65	0.40	134	P 2	TWD	14	AV4	-0.15	TEH	TEC	7	COLD	720UL
		0.28	55	P 2	TWD	10	AV3	+0.17	TEH	TEC	7	COLD	720UL
		0.47	29	P 2	TWD	17	AV2	+0.02	TEH	TEC	7	COLD	720UL

Tubes with 20-39% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT		CAL #	LEG	PROBE
33	78	0.83	134	P 2	TWD	28	AV3	-0.05	TEH	TEC	2	COLD	720UL

Total Tubes : 1
Total Records: 1

Tubes with 40-100% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	CAL #	LEG	PROBE

None Reported

Total Tubes : 0
Total Records: 0

Total Records: 0

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 4
Component: S/G C

Tubes with 1-19% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	CAL #	LEG	PROBE
13	4	0.24	59	P 2	TWD	11	AV4	+0.23	TEH TEC	3	COLD	720UL
13	44	0.19	147	P 2	TWD	10	AV3	-0.88	TEH TEC	37	COLD	720UL
22	7	0.33	66	P 2	TWD	14	AV2	+0.00	TEH TEC	1	COLD	720UL
22	83	0.23	214	P 2	TWD	12	AV4	-0.16	TEH TEC	21	COLD	720UL
26	82	0.24	12	P 2	TWD	13	AV1	+0.14	TEH TEC	21	COLD	720UL
27	80	0.36	40	P 2	TWD	15	AV3	-0.05	TEH TEC	19	COLD	720UL
32	16	0.34	23	P 2	TWD	15	AV2	+0.00	TEH TEC	4	COLD	720UL
32	70	0.35	38	P 2	TWD	16	AV3	-0.09	TEH TEC	13	COLD	720UL
34	75	0.22	21	P 2	TWD	10	AV4	+0.00	TEH TEC	19	COLD	720UL

Total Tubes : 9
Total Records: 9

Tubes with 20-39% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	CAL #	LEG	PROBE
32	70	0.63	35	P 2	TWD	24	AV1	+0.09	TEH TEC	13	COLD	720UL
35	31	0.62	66	P 2	TWD	28	AV2	+0.19	TEH TEC	10	COLD	720UL

Total Tubes : 2
Total Records: 2

Tubes with 40-100% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	CAL #	LEG	PROBE

None Reported

Total Tubes : 0
Total Records: 0

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 4
Component: S/G B

Tubes with 1-19% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	CAL #	LEG	PROBE
21	6	0.30	51	P 2	TWD	11	AV3	-0.14	TEH TEC	35	COLD	720UL
23	50	0.45	78	P 2	TWD	16	AV3	-0.17	TEH TEC	9	COLD	720UL
27	72	0.27	140	P 2	TWD	11	AV1	+0.02	TEH TEC	5	COLD	720UL
		0.29	18	P 2	TWD	12	AV2	-0.02	TEH TEC	5	COLD	720UL
30	65	0.49	57	P 2	TWD	18	AV2	+0.21	TEH TEC	7	COLD	720UL
30	73	0.27	22	P 2	TWD	11	AV3	-0.02	TEH TEC	5	COLD	720UL
		0.33	35	P 2	TWD	13	AV4	-0.09	TEH TEC	5	COLD	720UL
31	13	0.28	61	P 2	TWD	12	AV4	-0.02	TEH TEC	39	COLD	720UL
33	16	0.39	38	P 2	TWD	14	AV4	+0.00	TEH TEC	22	COLD	720UL
34	46	0.43	39	P 2	TWD	15	AV2	-0.35	TEH TEC	13	COLD	720UL
35	54	0.30	46	P 2	TWD	11	AV3	+0.39	TEH TEC	9	COLD	720UL
38	58	0.35	71	P 2	TWD	13	AV3	+0.07	TEH TEC	8	COLD	720UL
44	38	0.19	0	P5	WAR	9	04C	+0.54	04C 04C	43	COLD	720PP

Total Tubes : 11
Total Records: 13

Tubes with 20-39% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	CAL #	LEG	PROBE

None Reported

Total Tubes : 0
Total Records: 0

Tubes with 40-100% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	CAL #	LEG	PROBE

None Reported

Total Tubes : 0

Total Records: 0

Framatome ANP Inc.
Customer Name: Turkey Point - Unit 4
Component: S/G C

Tubes with 1-19% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	CAL #	LEG	PROBE
13	4	0.24	59	P 2	TWD	11	AV4	+0.23	TEH TEC	3	COLD	720UL
13	44	0.19	147	P 2	TWD	10	AV3	-0.88	TEH TEC	37	COLD	720UL
22	7	0.33	66	P 2	TWD	14	AV2	+0.00	TEH TEC	1	COLD	720UL
22	83	0.23	214	P 2	TWD	12	AV4	-0.16	TEH TEC	21	COLD	720UL
26	82	0.24	12	P 2	TWD	13	AV1	+0.14	TEH TEC	21	COLD	720UL
27	80	0.36	40	P 2	TWD	15	AV3	-0.05	TEH TEC	19	COLD	720UL
32	16	0.34	23	P 2	TWD	15	AV2	+0.00	TEH TEC	4	COLD	720UL
32	70	0.35	38	P 2	TWD	16	AV3	-0.09	TEH TEC	13	COLD	720UL
34	75	0.22	21	P 2	TWD	10	AV4	+0.00	TEH TEC	19	COLD	720UL

Total Tubes : 9
Total Records: 9

Tubes with 20-39% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION		EXT	CAL #	LEG	PROBE
32	70	0.63	35	P 2	TWD	24	AV1	+0.09	TEH TEC	13	COLD	720UL
35	31	0.62	66	P 2	TWD	28	AV2	+0.19	TEH TEC	10	COLD	720UL

Total Tubes : 2
Total Records: 2

Tubes with 40-100% TWD Indications

ROW	COL	VOLTS	DEG	CHN	IND	%TW	LOCATION	EXT	CAL #	LEG	PROBE

None Reported

Total Tubes : 0
Total Records: 0

SECTION 6

TECHNICAL SPECIFICATION BASES CHANGES

(Procedure 0-ADM-536)

Technical Specification Bases Control Program

Amendments 222 and 217 to the Turkey Point Units 3 and 4 operating licenses, respectively, added Technical Specification 6.8.4.i, Technical Specification Bases Control Program. Technical Specification 6.8.4.i.d requires changes to Technical Specification bases that do not require prior NRC approval to be submitted to the NRC "... on a frequency consistent with 10 CFR 50.71(e)." The report of changes made pursuant to 10 CFR 50.59 is also submitted consistent with 10 CFR 50.71(e) (the FSAR update). Therefore, changes made to the Technical Specification bases are being submitted with this report and are contained in Procedure 0-ADM-536, Technical Specification Bases Control Program, which is provided in Attachment 2. A summary of the changes made since Amendments 222 and 217 were issued follows:

Procedure Change:

RTS No. 03-0867

There were two changes incorporated into 0-ADM-536 by RTS No. 03-0867. They were incorporated into 0-ADM-536 on December 23, 2003 and are described below:

ENGINEERING EVALUATION PTN-ENG-SENS-03-0046

Unit : 3 and 4

ENABLING THE COLD OVERPRESSURE MITIGATION SYSTEM AT HIGHER TEMPERATURE

Summary:

Technical Specification 3.4.9.3 requires an Overpressure Mitigation System (OMS) to be operable when reactor coolant system (RCS) temperature is less than 275 degrees F. In addition, a footnote applicable to Technical Specification Surveillance Requirements 4.4.9.3.1.a and 4.4.9.3.1.d allows 12 hours to perform them after reaching 275 degrees F. Since OMS can be enabled at temperatures above 275 degrees F, Bases Section 3/4.4.9 has been revised to clarify that the 12-hour surveillance clock indicated in the footnote begins upon enabling OMS and not when RCS temperature reaches 275 degrees F.

ENGINEERING EVALUATION PTN-ENG-SEFJ-02-016

Unit : 3 and 4

POTENTIAL CORE RECRITICALITY DURING HOT LEG SWITCHOVER FOLLOWING A LARGE COLD LEG BREAK LOCA

Summary:

This issue only applies to the recovery phase from large cold leg break loss of coolant accidents (LOCA). It does not apply to large hot leg break LOCAs or small break LOCAs.

The concern relates to the possibility of the core becoming critical again at the time of hot leg switchover (HLSO) during the recovery phase from large cold leg break LOCAs. Following the blowdown period of a large break LOCA (LBLOCA), the reactor is refilled by the emergency core cooling system (ECCS) using borated water from the Refueling Water Storage Tank (RWST) and the ECCS accumulators. For cold leg breaks, decay heat boils off pure ECCS water while the boron is left behind thereby increasing the boron concentration in the core. The sump boron concentration decreases as boron deficient steam leaving the vessel and exiting the reactor coolant system (RCS) through the broken cold leg break condenses in the containment and returns to the sump. The core remains subcritical due to the presence of voids and an increasing boron concentration. To prevent the boron concentration in the core from reaching precipitation levels, ECCS injection is switched from cold leg to hot leg. At the time of hot leg switchover, the nuclear steam supply system vendor postulated that excessively diluted ECCS fluid could be introduced at the top of the core and, without mixing, could displace the highly borated liquid in the core thus resulting in a return to criticality. The potential for recriticality at HLSO time is not an issue for hot leg breaks because, for these type of breaks, the excess ECCS fluid does not boil off but flows through the core and out through the break thus precluding boron buildup in the core. In either LBLOCA case described above, control rod insertion had not been credited. This evaluation extends the subcriticality methodology to the time of HLSO, for the cold leg LBLOCA only, to provide credit for the negative reactivity from the inserted control rods and from the presence of xenon still in the core at the time of HLSO.

Technical Specification Bases Section 3/4.5.4 have been revised to indicate that cold leg LBLOCA analyses now take credit for control rod insertion at the time of HLSO to provide additional negative reactivity to prevent criticality.

Attachment 2

Turkey Point Nuclear Plant

Procedure 0-ADM-536

Technical Specification Bases Control Program

Florida Power & Light Company

This procedure may be affected by an O.T.S.C. (On The Spot Change) verify information prior to use Date verified_________ Initials______

Turkey Point Nuclear Plant

0-ADM-536

<u>Title</u>:

Technical Specification Bases Control Program

Responsible Department:	Licensing
Revision Approval Date:	12/23/03C
Periodic Review Due:	2/13/08

RTSs *90-2107, 93-0005, 96-0153, 97-1414, 98-0772, 99-0283, 99-1074P, 00-0489, 01-0100P, 03-0049, 03-0231, 03-0867*

W97:DPS/ms/mrg/mrg

LIST OF EFFECTIVE PAGES

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1	12/23/03C	31	05/01/03	61	05/01/03	91	05/01/03
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3	03/04/03	33	05/01/03	63	05/01/03	93	05/01/03
4	12/23/03	34	05/01/03	64	05/01/03	94	05/01/03
5	03/04/03	35	05/01/03	65	05/01/03	95	05/01/03
6	03/04/03	36	05/01/03	66	05/01/03	96	05/01/03
7	03/04/03	37	05/01/03	67	05/01/03	97	05/01/03
8	03/04/03	38	05/01/03	68	12/23/03	98	05/01/03
9	03/04/03	39	05/01/03	69	05/01/03	99	05/01/03
10	03/04/03	40	05/01/03	70	05/01/03	100	05/01/03
11	05/01/03	41	05/01/03	71	05/01/03	101	05/01/03
12	05/01/03	42	05/01/03	72	05/01/03	102	05/01/03
13	05/01/03	43	05/01/03	73	12/23/03	103	05/01/03
14	05/01/03	44	05/01/03	74	05/01/03	104	05/01/03
15	05/01/03	45	05/01/03	75	05/01/03	105	05/01/03
16	05/01/03	46	05/01/03	76	05/01/03	106	05/01/03
17	05/01/03	47	05/01/03	77	05/01/03	107	05/01/03
18	05/01/03	48	05/01/03	78	05/01/03	108	05/01/03
19	05/01/03	49	05/01/03	79	05/01/03	109	05/01/03
20	05/01/03	50	05/01/03	80	05/01/03	110	05/01/03
21	05/01/03	51	05/01/03	81	05/01/03	111	05/01/03
22	05/01/03	52	05/01/03	82	05/01/03	112	05/01/03
23	05/01/03	53	05/01/03	83	05/01/03		
24	05/01/03	54	05/01/03	84	05/01/03		
25	05/01/03	55	05/01/03	85	05/01/03		
26	05/01/03	56	05/01/03	86	05/01/03		
27	05/01/03	57	05/01/03	87	05/01/03		
28	05/01/03	58	05/01/03	88	05/01/03		
29	05/01/03	59	05/01/03	89	05/01/03		
30	05/01/03	60	05/01/03	90	05/01/03		

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1.0 PURPOSE

1.1 This procedure provides instructions for the preparation, review, approval, distribution and revision of Technical Specification (TS) Bases.

1.2 TS Bases changes are not a substitute for a License Amendment. The discussion provided in the Bases cannot change the meaning or intent of the Technical Specifications. The Bases can only provide guidance in what is necessary to meet the intent of the Technical Specifications.

1.3 Licensees may make changes to the Bases without prior NRC approval provided the changes do not require either of the following:

1.3.1 Change in the TS incorporated in the license, or

1.3.2 A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

2.0 REFERENCES/RECORDS REQUIRED/COMMITMENT DOCUMENTS

2.1 References

2.1.1 Quality Instructions/Plant Procedures

1. 0-ADM-100, Preparation, Revision, Review, Approval and Use of Procedures
2. 0-ADM-104, 10 CFR 50.59 Applicability/Screening Reviews
3. 0-ADM-507, Processing Engineering Evaluations
4. 0-ADM-518, Condition Reports

2.1.2 Regulatory Guidelines

1. NUREG-1431, Westinghouse Standard Technical Specifications
2. 10 CFR 50.59, Changes, Tests and Experiments
3. 10 CFR 50.71, Maintenance of Records Making Reports
4. 10 CFR 50.36, Technical Specification

2.1.3 Miscellaneous Documents (i.e., PC/M, Correspondence)

1. ENG-QI 2.0, Engineering Evaluation
2. ENG-QI 2.1, 10 CFR 50.59 Applicability/Screening/Evaluation
3. CR-98-0382
4. NRC SER, dated 3/3/03, **Turkey Point Units 3 and 4 – Issuance of Amendments Regarding Missed Surveillance and Adoption of a Technical Specifications Bases Control Program**
5. PTN-ENG-SENS-03-0046, Rev. 0 |
6. PTN-ENG-SEFJ-02-016, Rev. 0 |

2.2 Records Required

2.2.1 Completed copies of the below listed item(s) constitute Quality Assurance records and shall be transmitted to QA Records for retention in accordance with Quality Assurance Records Program requirements:

1. None.

2.3 Commitment Documents

2.3.1 Amendment No 182/176, NRC Letter dated, February 13, 1996

3.0 RESPONSIBILITIES

3.1 The Plant General Manager is responsible for approval of all Technical Specification Bases changes.

3.2 The Plant Nuclear Safety Committee (PNSC) is responsible for review and recommending approval or disapproval of all Technical Specification Bases changes.

3.3 The Operations Manager is responsible for reviewing the Technical Specification Bases changes for plant operational impact.

3.4 The Licensing Manager is responsible for:

3.4.1 Submitting to the NRC changes to the Technical Specification Bases on the same schedule as periodic update to the FSAR as required by 10 CFR 50.71(e)

3.4.2 Reviewing the Technical Specification Bases changes and the overall implementation of this procedure.

3.5 The responsible individual for proposed changes to the TS Bases shall process the change in accordance with 0-ADM-100, Preparation, Revision, Review, Approval and Use of Procedures.

4.0 DEFINITIONS

4.1 10 CFR 50.59 Evaluation

4.1.1 The documented evaluation against the eight criteria in 10 CFR 50.59(c)(2) to determine if a proposed change, test, or experiment requires prior NRC approval.

4.1.2 Many changes to the Bases will not require a formal 10 CFR 50.59 evaluation. These cases require a 10 CFR 50.59 Applicability Determination/Screening Review.

4.2 Technical Specification Bases

4.2.1 A set of documentation providing the basis of the Technical Specifications and their application to physical systems in the plant.

5.0 PROCEDURE

5.1 Technical Specification Bases Changes

5.1.1 Changes to the Technical Specification Bases shall be processed as a revision to this procedure in accordance with the plant's procedure change process specified in 0-ADM-100, Preparation, Revision, Review, Approval and Use of Procedures.

NOTE

Any 10 CFR 50.59 Evaluations that support TS Bases changes contained in this procedure shall be presented to PNSC as part of change package.

5.1.2 Proposed changes to the Technical Specification Bases should take into consideration the Bases for the similar specification in NUREG 1431, Westinghouse Standard Technical Specifications and Bases; Updated Final Safety Analysis Report; Design Basis Documents; NRC correspondence and other applicable documents. All references changing the TS Bases should be listed in the reference section of this procedure.

5.1.3 An updated TS Bases procedure shall be sent to NRC on a frequency consistent with 10 CFR 50.71(e) reporting requirements.

5.1.4 TS Bases changes shall be evaluated for prior NRC approval in accordance with 10 CFR 50.59 applicability/screening methodology as delineated in 0-ADM-104, 10 CFR 50.59 APPLICABILITY/SCREENING REVIEWS.

END OF TEXT

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ATTACHMENT 1
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TECHNICAL SPECIFICATION BASES

BASES

FOR

SECTION 2.0

SAFETY LIMITS

AND

LIMITING SAFETY SYSTEM SETTINGS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Section 2.0, but in accordance with 10 CFR 50.36 are not part of the Technical Specifications..

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TECHNICAL SPECIFICATION BASES

2.1 SAFETY LIMITS

2.1.1 REACTOR CORE

The restrictions of this Safety Limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and reactor coolant temperature and pressure have been related to DNB. This relationship has been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions. The local DNB heat flux ratio (DNBR) is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux and is indicative of the margin to DNB.

The DNB design basis is as follows: there must be at least a 95 percent probability with 95 percent confidence that the minimum DNBR of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used. The correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95 percent probability with 95 percent confidence that DNB will not occur when the minimum DNBR is at the DNBR limit.

The curves of Figure 2.1-1 show the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature for which the minimum DNBR is no less than the design DNBR value, or the average enthalpy at the vessel exit is equal to the enthalpy of saturated liquid.

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TECHNICAL SPECIFICATION BASES

2.1.1 REACTOR CORE (Cont'd)

These curves are based on an enthalpy hot channel factor, $F^N_{\Delta H}$, and a reference cosine with a peak of 1.55 for axial power shape. An allowance is included for an increase in $F^N_{\Delta H}$ at reduced power based on the expression:

$$F^N_{\Delta H} \leq F^{RTP}_{\Delta H}[1+ PF_{\Delta H}(1-P)]$$

Where P is the fraction of RATED THERMAL POWER.

$F^{RTP}_{\Delta H}$ = $F_{\Delta H}$ limit at RATED THERMAL POWER as specified in the CORE OPERATING LIMITS REPORT.

$PF_{\Delta H}$ = Power Factor multiplier for $F_{\Delta H}$ as specified in the CORE OPERATING LIMITS REPORT.

These limiting heat flux conditions are higher than those calculated for the range of all control rods fully withdrawn to the maximum allowable control rod insertion limit assuming the axial power imbalance is within the limits of the f (ΔT) function of the Overtemperature trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature ΔT trips will reduce the setpoints to provide protection consistent with core Safety Limits.

Fuel rod bowing reduces the values of DNB ratio (DNBR). The penalties are calculated pursuant to "Fuel Rod Bow Evaluation," WCAP-8691-P-A Revision 1 (Proprietary) and WCAP-8692 Revision 1 (Non-Proprietary). The restrictions of the Core Thermal Hydraulic Safety Limits assure that an amount of DNBR margin greater than or equal to the above penalties is retained to offset the rod bow DNBR penalty.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System (RCS) from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The reactor vessel and pressurizer are designed to Section III of the ASME Code for Nuclear Power Plants which permits a maximum transient pressure of 110% (2735 psig) of design pressure. The RCS piping, valves and fittings are designed to ANSI B31.1 which permits a maximum transient pressure of 120% of design pressure of 2485 psig. The Safety Limit of 2735 psig is therefore more conservative than the ANSI B31.1 design criteria and consistent with associated ASME Code requirements.

The entire RCS is hydrotested at 125% (3107 psig) of design pressure, to demonstrate integrity prior to initial operation.

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TECHNICAL SPECIFICATION BASES

2.2 LIMITING SAFETY SYSTEM SETTINGS

2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Trip Setpoint Limits specified in Table 2.2-1 are the nominal values at which the Reactor trips are set for each functional unit. The Trip Setpoints have been selected to ensure that the core and Reactor Coolant System are prevented from exceeding their safety limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. The setpoint for a reactor trip system or interlock function is considered to be adjusted consistent with the Nominal Trip Setpoint when the "as measured" setpoint is within the band allowed for calibration accuracy.

To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, statistical allowances are provided for in the Nominal Trip Setpoint and Allowable Values in accordance with the setpoint methodology described in WCAP's 12201 and 12745. Surveillance criteria have been determined and are controlled in Plant procedures and in design documents. The surveillance criteria ensure that instruments which are not operating within the assumptions of the setpoint calculations are identified. An instrument channel is considered OPERABLE when the surveillance is within the Allowable Value and the channel is capable of being calibrated in accordance with Plant procedures. Sensor and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

The inability to demonstrate through measurement and/or analytical means, using the methods described in WCAP's 12201 and 12745 ($TA \geq R+S+Z$), that the Reactor Trip function would have occurred within the values specified in the design documentation provides a threshold value for REPORTABLE EVENTS.

There is a small statistical probability that a properly functioning device will drift beyond determined surveillance criteria. Infrequent drift outside the surveillance criteria are expected. Excessive rack or sensor drift that is more than occasional, may be indicative of more serious problems and should warrant further investigations.

The various Reactor trip circuits automatically open the Reactor trip breakers whenever a condition monitored by the Reactor Trip System reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a Reactor Trip System which monitors numerous system variables, therefore providing Trip System functional diversity. The functional capability at the specified trip setting is required for those anticipatory or diverse Reactor trips for which no direct credit was assumed in the safety analysis to enhance the overall reliability of the Reactor Trip System. The Reactor Trip System initiates a Turbine trip signal whenever Reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive Reactor Coolant System cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System.

TECHNICAL SPECIFICATION BASES

2.2 LIMITING SAFETY SYSTEM SETTINGS (Continued)

Manual Reactor Trip

The Reactor Trip System includes manual Reactor trip capability.

Power Range, Neutron Flux

In each of the Power Range Neutron Flux channels there are two independent bistables, each with its own trip setting used for a High and Low Range trip setting. The Low Setpoint trip provides protection during subcritical and low power operations to mitigate the consequences of a power excursion beginning from low power, and the High Setpoint trip provides protection during power operations for all power levels to mitigate the consequences of a reactivity excursion which may be too rapid for the temperature and pressure protective trips.

The Low Setpoint trip may be manually blocked above P-10 (a power level of approximately 10% of RATED THERMAL POWER) and is automatically reinstated below the P-10 Setpoint.

Intermediate and Source Range, Neutron Flux

The Intermediate and Source Range, Neutron Flux trips provide core protection during reactor startup to mitigate the consequences of an uncontrolled rod cluster control assembly bank withdrawal from a subcritical condition. These trips provide redundant protection to the Low Setpoint trip of the Power Range, Neutron Flux channels. The Source Range channels will initiate a Reactor trip at about 10^5 counts per second unless manually blocked when P-6 becomes active. The Intermediate Range channels will initiate a Reactor trip at a current level equivalent to approximately 25% of RATED THERMAL POWER unless manually blocked when P-10 becomes active. No credit is taken for operation of the trips associated with either the Intermediate or Source Range Channels in the accident analyses; however, their functional capability at the specified trip settings is required by this specification to enhance the overall reliability of the Reactor Protection System.

Overtemperature ΔT

The Overtemperature ΔT trip provides core protection to prevent DNB for all combinations of pressure, power, coolant temperature, and axial power distribution, provided that the transient is slow with respect to piping transit delays from the core to the temperature detectors and pressure is within the range between the Pressurizer High and Low Pressure trips. The setpoint is automatically varied with: (1) coolant temperature to correct for temperature induced changes in density and heat capacity of water and includes dynamic compensation for piping delays from the core to the loop temperature detectors, (2) pressurizer pressure, and (3) axial power distribution. With normal axial power distribution, this Reactor trip limit is always below the core Safety Limit as shown in Figure 2.1-1. If axial peaks are greater than design, as indicated by the difference between top and bottom power range nuclear detectors, the Reactor trip is automatically reduced according to the notations in Table 2.2-1.

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TECHNICAL SPECIFICATION BASES

2.2 LIMITING SAFETY SYSTEM SETTINGS (Continued)

Overpower ΔT

The Overpower ΔT trip prevents power density anywhere in the core from exceeding 118% of the design power density. This provides assurance of fuel integrity (e.g., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions, limits the required range for Overtemperature ΔT trip, and provides a backup to the High Neutron Flux trip. The setpoint is automatically varied with: (1) coolant temperature to correct for temperature induced changes in density and heat capacity of water, (2) rate of change of temperature for dynamic compensation for piping delays from the core to the loop temperature detectors to ensure that the allowable heat generation rate (kW/ft) is not exceeded.

Pressurizer Pressure

In each of the pressurizer pressure channels, there are two independent bistables, each with its own trip setting to provide for a High and Low Pressure trip thus limiting the pressure range in which reactor operation is permitted. The Low Setpoint trip protects against low pressure which could lead to DNB by tripping the reactor in the event of a loss of reactor coolant pressure.

On decreasing power the Low Setpoint trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with turbine first stage pressure at approximately 10% of full power equivalent); and on increasing power, automatically reinstated by P-7.

The High Setpoint trip functions in conjunction with the pressurizer safety valves to protect the Reactor Coolant System against system overpressure.

Pressurizer Water Level

The Pressurizer Water Level-High trip is provided to prevent water relief through the pressurizer safety valves. On decreasing power the Pressurizer High Water Level trip is automatically blocked by P–7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine first stage pressure at approximately 10% of full power equivalent); and on increasing power, automatically reinstated by P-7.

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TECHNICAL SPECIFICATION BASES

2.2 LIMITING SAFETY SYSTEM SETTINGS (Continued)

Reactor Coolant Flow

The Reactor Coolant Flow-Low trip provides core protection to prevent DNB by mitigating the consequences of a loss of flow resulting from the loss of one or more reactor coolant pumps.

On increasing power above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a turbine first stage pressure at approximately 10% of full power equivalent), an automatic Reactor trip will occur if the flow in more than one loop drops below 90% of loop design flow. Above P-8 (a power level of approximately 45% of RATED THERMAL POWER) an automatic Reactor trip will occur if the flow in any single loop drops below 90% of nominal full loop flow. Conversely, on decreasing power between P–8 and the P-7 an automatic Reactor trip will occur on low reactor coolant flow in more than one loop and below P-7 the trip function is automatically blocked.

Steam Generator Water Level

The Steam Generator Water Level Low-Low trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch resulting from loss of normal feedwater. The specified setpoint provides allowances for starting delays of the Auxiliary Feedwater System.

Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level

The Steam/Feedwater Flow Mismatch in coincidence with a Steam Generator Water Level-Low trip is not used in the transient and accident analyses but is included in Table 2.2-1 to ensure the functional capability of the specified trip settings and thereby enhance the overall reliability of the Reactor Trip System. This trip is redundant to the Steam Generator Water Level Low-Low trip. The Steam/Feedwater Flow Mismatch portion of this trip is activated when the steam flow exceeds the feedwater flow by greater than or equal to 0.665×10^6 lbs/hour. The Steam Generator Water Level-Low portion of the trip is activated when the water level drops below 10%, as indicated by the narrow range instrument. These trip values include sufficient allowance in excess of normal operating values to preclude spurious trips but will initiate a Reactor trip before the steam generators are dry. Therefore, the required capacity and starting time requirements of the auxiliary feedwater pumps are reduced and the resulting thermal transient on the Reactor Coolant System and steam generators is minimized.

TECHNICAL SPECIFICATION BASES

2.2 LIMITING SAFETY SYSTEM SETTINGS (Continued)

Undervoltage - 4.16 kV Bus A and B Trips

The 4.16 kV Bus A and B Undervoltage trips provide core protection against DNB as a result of complete loss of forced coolant flow. The specified setpoint assures a Reactor trip signal is generated before the Low Flow Trip Setpoint is reached. Time delays are incorporated in the Undervoltage trips to prevent spurious Reactor trips from momentary electrical power transients. The delay is set so that the time required for a signal to reach the Reactor trip breakers following the trip of at least one undervoltage relay in both of the associated Units 4.16 kV busses shall not exceed 1.3 seconds. On decreasing power the Undervoltage Bus trips are automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine first stage pressure at approximately 10% of full power equivalent); and on increasing power, reinstated automatically by P-7.

Turbine Trip

A Turbine trip initiates a Reactor trip. On decreasing power, the Reactor Trip from the Turbine trip is automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine first stage pressure at approximately 10% of full power equivalent); and on increasing power, reinstated automatically by P-7.

Safety Injection Input from ESF

If a Reactor trip has not already been generated by the Reactor Trip System instrumentation, the ESF automatic actuation logic channels will initiate a Reactor trip upon any signal which initiates a Safety Injection. The ESF instrumentation channels which initiate a Safety Injection signal are shown in Table 3.3-3.

Reactor Coolant Pump Breaker Position Trip

The Reactor Coolant Pump Breaker Position Trips are anticipatory trips which provide reactor core protection against DNB. The open/close position trips assure a reactor trip signal is generated before the low flow trip setpoint is reached. Their functional capability at the open/close position settings is required to enhance the overall reliability of the Reactor Protection System. Above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a turbine first stage pressure at approximately 10% of full power equivalent) an automatic reactor trip will occur if more than one reactor coolant pump breaker is opened. Above P-8 (a power level of approximately 45% of RATED THERMAL POWER) an automatic reactor trip will occur if one reactor coolant pump breaker is opened. On decreasing power between P-8 and P-7, an automatic reactor trip will occur if more than one reactor coolant pump breaker is opened and below P-7 the trip function is automatically blocked.

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TECHNICAL SPECIFICATION BASES

2.2 LIMITING SAFETY SYSTEM SETTINGS (Continued)

Reactor Coolant Pump Breaker Position Trip (Continued)

Underfrequency sensors are also installed on the 4.16 kV busses to detect underfrequency and initiate breaker trip on underfrequency. The underfrequency trip setpoints preserve the coast down energy of the reactor coolant pumps, in case of a grid frequency decrease so DNB does not occur.

Reactor Trip System Interlocks

The Reactor Trip System interlocks perform the following functions:

P-6 On increasing power, P-6 allows the manual block of the Source Range trip (i.e., prevents premature block of Source Range trip) and deenergizes the high voltage to the detectors. On decreasing power, Source Range Level trips are automatically reactivated and high voltage restored.

P-7 On increasing power, P-7 automatically enables Reactor trips on low flow in more than one reactor coolant loop, more than one reactor coolant pump breaker open, reactor coolant pump bus undervoltage and underfrequency, Turbine trip, pressurizer low pressure and pressurizer high level. On decreasing power, the above listed trips are automatically blocked.

P-8 On increasing power, P-8 automatically enables Reactor trips on low flow in one or more reactor coolant loops, and one or more reactor coolant pump breakers open. On decreasing power, the P-8 interlock automatically blocks the trip on low flow in one coolant loop or one coolant pump breaker open.

P-10 On increasing power, P-10 allows the manual block of the Intermediate Range trip and the Low Setpoint Power Range trip; and automatically blocks the Source Range trip and deenergizes the Source Range high voltage power. On decreasing power, the Intermediate Range trip and the Low Setpoint Power Range trip are automatically reactivated. P-10 also provides input to P-7. The trip setpoint on increasing power shall be ≥ 10% and the reset point shall be less than or equal to 10%.

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TECHNICAL SPECIFICATION BASES

BASES FOR

SECTIONS 3.0 AND 4.0

LIMITING CONDITIONS FOR OPERATION

AND

SURVEILLANCE REQUIREMENTS

NOTE

The BASES contained in succeeding pages summarize the reasons for the Specifications in Sections 3.0 and 4.0, but in accordance with 10 CFR 50.36 are not part of the Technical Specifications.

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TECHNICAL SPECIFICATION BASES

3/4 LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

3/4.0 APPLICABILITY

Specification 3.0.1 through 3.0.5 establish the general requirements applicable to Limiting Conditions for Operation. These requirements are based on the requirements for Limiting Conditions for Operation stated in the Code of Federal Regulations, 10 CFR 50.36(c)(2):

"Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specification until the condition can be met."

Specification 3.0.1 establishes the Applicability statement within each individual specification as the requirement for when (i.e., in which OPERATIONAL MODES or other specified conditions) conformance to the Limiting Conditions for Operation is required for safe operation of the facility. The ACTION requirements establish those remedial measures that must be taken within specified time limits when the requirements of a Limiting Condition for Operation are not met.

There are two basic types of ACTION requirements. The first specifies the remedial measures that permit continued operation of the facility which is not further restricted by the time limits of the ACTION requirements. In this case, conformance to the ACTION requirements provides an acceptable level of safety for unlimited continued operation as long as the ACTION requirements continue to be met. The second type of ACTION requirement specifies a time limit in which conformance to the conditions of the Limiting Condition for Operation must be met. This time limit is the allowable outage time to restore an inoperable system or component to OPERABLE status or for restoring parameters within specified limits. If these actions are not completed within the allowable outage time limits, a shutdown is required to place the facility in a MODE or condition in which the specification no longer applies. It is not intended that the shutdown ACTION requirements be used as an operational convenience which permits (routine) voluntary removal of a system(s) or component(s) from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

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TECHNICAL SPECIFICATION BASES

3/4.0 APPLICABILITY (Continued)

The specified time limits of the ACTION requirements are applicable from the point in time it is identified that a Limiting Condition for Operation is not met. The time limits of the ACTION requirements are also applicable when a system or component is removed from service for surveillance testing or investigation of operational problems. Individual specifications may include a specified time limit for the completion of a Surveillance Requirement when equipment is removed from service. In this case, the allowable outage time limits of the ACTION requirements are applicable when this limit expires if the surveillance has not been completed. When a shutdown is required to comply with ACTION requirements, the plant may have entered a MODE in which a new specification becomes applicable. In this case, the time limits of the ACTION requirements would apply from the point in time that the new specification becomes applicable if the requirements of the Limiting Condition for Operation are not met.

Specification 3.0.2 establishes that noncompliance with a specification exists when the requirements of the Limiting Condition for Operation are not met and the associated ACTION requirements have not been implemented within the specified time interval. The purpose of this specification is to clarify that (1) implementation of the ACTION requirements within the specified time interval constitutes compliance with a specification and (2) completion of the remedial measures of the ACTION requirements is not required when compliance with a Limiting Condition of Operation is restored within the time interval specified in the associated ACTION requirements.

Specification 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements. The purpose of this specification is to delineate the time limits for placing the unit in a safe shutdown MODE when plant operation cannot be maintained within the limits for safe operation defined by the Limiting Conditions for Operation and its ACTION requirements. It is not intended to be used as an operational convenience which permits (routine) voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable. One hour is allowed to prepare for an orderly shutdown before initiating a change in plant operation. This time permits the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the cooldown capabilities of the facility assuming only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the primary coolant system and the potential for a plant upset that could challenge safety systems under conditions for which this specification applies.

TECHNICAL SPECIFICATION BASES

3/4.0 APPLICABILITY (Continued)

If remedial measures permitting limited continued operation of the facility under the provisions of the ACTION requirements are completed, the shutdown may be terminated. The time limits of the ACTION requirements are applicable from the point in time there was a failure to meet a Limiting Condition for Operation. Therefore, the shutdown may be terminated if the ACTION requirements have been met or the time limits of the ACTION requirements have not expired, thus providing an allowance for the completion of the required actions.

The time limits of Specification 3.0.3 allow 37 hours for the plant to be in the COLD SHUTDOWN MODE when a shutdown is required during the POWER MODE of operation. If the plant is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE of operation applies. However, if a lower MODE of operation is reached in less time than allowed, the total allowable time to reach COLD SHUTDOWN, or other applicable MODE, is not reduced. For example, if HOT STANDBY is reached in 2 hours, the time allowed to reach HOT SHUTDOWN is the next 11 hours because the total time to reach HOT SHUTDOWN is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into a MODE or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher MODE of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower MODE of operation.

The shutdown requirements of Specification 3.0.3 do not apply in MODES 5 and 6, because the ACTION requirements of individual specifications define the remedial measures to be taken.

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TECHNICAL SPECIFICATION BASES

3/4.0 APPLICABILITY (Continued)

Specification 3.0.4 establishes limitations on MODE changes when a Limiting Condition for Operation is not met. It precludes placing the facility in a higher MODE of operation when the requirements for a Limiting Condition for Operation are not met and continued noncompliance to these conditions would result in a shutdown to comply with the ACTION requirements if a change in MODES were permitted. The purpose of this specification is to ensure that facility operation is not initiated or that higher MODES of operation are not entered when corrective action is being taken to obtain compliance with a specification by restoring equipment to OPERABLE status or parameters to specified limits. Compliance with ACTION requirements that permit continued operation of the facility for an unlimited period of time provides an acceptable level of safety for continued operation without regard to the status of the plant before or after a MODE change. Therefore, in this case, entry into an OPERATIONAL MODE or other specified condition may be made in accordance with the provisions of the ACTION requirements. The provisions of this specification should not, however, be interpreted as endorsing the failure to exercise good practice in restoring systems or components to OPERABLE status before plant startup.

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 3.0.4 do not apply because they would delay placing the facility in a lower MODE of operation.

Specification 3.0.5 delineates the applicability of each specification to Unit 3 and Unit 4 operation.

Specification 4.0.1 through 4.0.5 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations, 10 CFR 50.36(c)(3):

"Surveillance requirements are requirements relating to test, calibration or inspection to ensure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

Specification 4.0.1 establishes the requirement that surveillances must be performed during the OPERATIONAL MODES or other conditions for which the requirements of the Limiting Conditions for Operation apply unless otherwise stated in an individual Surveillance Requirement. The purpose of this specification is to ensure that surveillances are performed to verify the operational status of systems and components and that parameters are within specified limits to ensure safe operation of the facility when the plant is in a MODE or other specified condition for which the associated Limiting Conditions for Operation are applicable. Surveillance Requirements do not have to be performed when the facility is in an OPERATIONAL MODE for which the requirements of the associated Limiting Condition for operation do not apply unless otherwise specified. The Surveillance Requirements associated with a Special Test Exception are only applicable when the Special Test Exception is used as an allowable exception to the requirements of a specification.

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TECHNICAL SPECIFICATION BASES

3/4.0 APPLICABILITY (Continued)

This requirement also establishes the failure to perform a Surveillance Requirement within the allowed surveillance interval, defined by the provisions of Specification 4.0.2, as a condition that constitutes a failure to meet the OPERABILITY requirements for a Limiting Condition for Operation. Under the provisions of this specification, systems and components are assumed to be OPERABLE when Surveillance Requirements have been satisfactorily performed within the specified time interval. However, nothing in this provision is to be construed as implying that systems or components are OPERABLE when they are found or known to be inoperable although still meeting the Surveillance Requirements.

Surveillance Requirements do not have to be performed on inoperable equipment because the ACTION requirements define the remedial measures that apply. However, the Surveillance Requirements have to be met to demonstrate that inoperable equipment has been restored to OPERABLE status.

Specification 4.0.2 establishes the conditions under which the specified time interval for Surveillance Requirements may be extended. It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g., transient conditions or other ongoing surveillance or maintenance activities. The limits of Specification 4.0.2 are based on engineering judgment and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. These provisions are sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval.

Specification 4.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance requirement has not been completed within the specified frequency. A delay period of up to 24 hours or up to the limit of the specified frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with Specification 4.0.2, and not at the time that the specified frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance requirement before complying with required ACTION(s) or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, Specification 4.0.3 allows for the full delay period of up to the specified frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

TECHNICAL SPECIFICATION BASES

Specification 4.0.3 provides a time limit for, and allowances for the performance of, a Surveillance that becomes applicable as a consequence of MODE changes imposed by required ACTION(s).

Failure to comply with the specified frequency for a Surveillance Requirement is expected to be an infrequent occurrence. Use of the delay period established by Specification 4.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65 (a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an *emergent condition* as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. A missed Surveillance for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All cases of a missed Surveillance will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the required ACTION(s) for the applicable Limiting Condition of Operation begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the required ACTION(s) for the applicable Limiting Condition of Operation begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with Specification 4.0.1.

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TECHNICAL SPECIFICATION BASES

3/4.0 APPLICABILITY (Continued)

Missed surveillance tests are reportable when the surveillance interval plus allowed surveillance interval extension, plus the LCO action statement time is exceeded. This means that a condition prohibited by the TS existed for a period of time longer than allowed by TS. If a TS surveillance is missed including the grace period, the equipment is inoperable. The TS LCO Action Statement is entered. If the time allowed by the action statement is exceeded, then it is reportable as a condition prohibited by the TS. The event is reportable even though the surveillance is subsequently satisfactorily performed. For example, if a TS requires a 31 day surveillance, and the grace period (25 %) is 7 days, and the equipment would be inoperable 38 days after the last surveillance. If the LCO allows 72 hours to restore the inoperable equipment to OPERABLE status (to perform a satisfactory surveillance), the missed surveillance would be reportable at the end of the 31 days + 7 days + 72 hours.

If the allowable outage time limits of the ACTION requirements are less than 24 hours or a shutdown is required to comply with ACTION requirements, e.g., Specification 3.0.3, a 24-hour allowance is provided to permit a delay in implementing the ACTION requirements. This provides an adequate time limit to complete Surveillance Requirements that have not been performed. The purpose of this allowance is to permit the completion of a surveillance before a shutdown is required to comply with ACTION requirements or before other remedial measures would be required that may preclude completion of a surveillance. The basis for this allowance includes consideration for plant conditions, adequate planning, availability of personnel, the time required to perform the surveillance, and the safety significance of the delay in completing the required surveillance. The provision also provides a time limit for the completion of Surveillance Requirements that become applicable as a consequence of MODE changes imposed by ACTION requirements and for completing Surveillance Requirements that are applicable when an exception to the requirements of Specification 4.0.4 is allowed. If a surveillance is not completed within the 24-hour allowance, the time limits of the ACTION requirements are applicable at that time. When a surveillance is performed within the 24-hour allowance and the Surveillance Requirements are not met, the time limits of the ACTION requirements are applicable at the time that the surveillance is terminated.

Surveillance Requirements do not have to be performed on inoperable equipment because the ACTION requirements define the remedial measures that apply. However, the Surveillance Requirements have to be met to demonstrate that inoperable equipment has been restored to OPERABLE status.

TECHNICAL SPECIFICATION BASES

3/4.0 APPLICABILITY (Continued)

Specification 4.0.4 establishes the requirement that all applicable surveillances must be met before entry into an OPERATIONAL MODE or other condition of operation specified in the Applicability statement. The purpose of this specification is to ensure that system and component OPERABILITY requirements or parameter limits are met before entry into a MODE or condition for which these systems and components ensure safe operation of the facility. This provision applies to changes in OPERATIONAL MODES or other specified conditions associated with plant shutdown as well as startup.

Under the provisions of this specification, the applicable Surveillance Requirements must be performed within the specified surveillance interval to ensure that the Limiting Conditions for Operation are met during initial plant startup or following a plant outage.

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 4.0.4 do not apply because this would delay placing the facility in a lower MODE of operation.

Specification 4.0.5 establishes the requirement that inservice inspection of ASME Code Class 1, 2, and 3 components and inservice testing of ASME Code Class 1, 2, and 3 pumps and valves shall be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50.55a.

This specification includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications and to remove any ambiguities relative to the frequencies for performing the required inservice inspection and testing activities.

Under the terms of this specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable Addenda. The requirements of Specification 4.0.4 to perform surveillance activities before entry into an OPERATIONAL MODE or other specified condition takes precedence over the ASME Boiler and Pressure. Vessel Code provision which allows pumps and valves to be tested up to one week after return to normal operation. The Technical Specification definition of OPERABLE does not allow a grace period before a component, that is not capable of performing its specified function, is declared inoperable and takes precedence over the ASME Boiler and Pressure Vessel Code provision which allows a valve to be incapable of performing its specified function for up to 24 hours before being declared inoperable.

Specification 4.0.6 delineates the applicability of the surveillance activities to Unit 3 and Unit 4 operations.

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TECHNICAL SPECIFICATION BASES

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 3/4.1.1.2 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that: (1) the reactor can be made subcritical from all operating conditions, (2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and (3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. Figure 3.1-1 shows the SHUTDOWN MARGIN equivalent to 1.77% Δk/k at the end-of-core-life with respect to an uncontrolled cooldown. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with FSAR safety analysis assumptions. With Tavg less than 200°F, the reactivity transients resulting from an inadvertent cooldown of the RCS or an inadvertent dilution of RCS boron are minimal and a 1% Δk/k SHUTDOWN MARGIN provides adequate protection.

The boron rate requirement of 16 gpm of 3.0 wt% (5245 ppm) boron or equivalent ensures the capability to restore the shutdown margin with one OPERABLE charging pump.

3/4.1.1.3 MODERATOR TEMPERATURE COEFFICIENT

The limitations on moderator temperature coefficient (MTC) are provided to ensure that the value of this coefficient remains within the limiting condition assumed in the FSAR accident and transient analyses.

The MTC values of this specification are applicable to a specific set of plant conditions; accordingly, verification of MTC values at conditions other than those explicitly stated will require extrapolation to those conditions in order to permit an accurate comparison.

The most negative MTC, value equivalent to the most positive moderator density coefficient (MDC), was obtained by incrementally correcting the MDC used in the FSAR analyses to nominal operating conditions. These corrections involved subtracting the incremental change in the MDC associated with a core condition of all rods inserted (most positive MDC) to an all rods withdrawn condition and, a conversion for the rate of change of moderator density with temperature at RATED THERMAL POWER conditions. This value of the MDC was then transformed into the limiting MTC value -3.5×10^{-4} Δk/k/°F. The MTC value of -3.0×10^{-4} Δk/k/°F represents a conservative value (with corrections for burnup and soluble boron) at a core condition of 300 ppm equilibrium boron concentration and is obtained by making these corrections to the limiting MTC value of -3.5×10^{-4} Δk/k/°F.

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TECHNICAL SPECIFICATION BASES

3/4.1 REACTIVITY CONTROL SYSTEMS (Continued)

3/4.1.1.3 MODERATOR TEMPERATURE COEFFICIENT (Continued)

The Surveillance Requirements for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup.

3/4.1.1.4 MINIMUM TEMPERATURE FOR CRITICALITY

This specification ensures that the reactor will not be made critical with the Reactor Coolant System average temperature less than 541°F. This limitation is required to ensure: (1) the moderator temperature coefficient is within its analyzed temperature range, (2) the trip instrumentation is within its normal operating range, (3) the pressurizer is capable of being in an OPERABLE status with a steam bubble, and (4) the reactor vessel is above its minimum RT_{NDT} temperature.

3/4.1.2 BORATION SYSTEMS

The Boron Injection System ensures that negative reactivity control is available during each mode of facility operation. The components required to perform this function include: (1) borated water sources, (2) charging pumps, (3) separate flow paths, and (4) boric acid transfer pumps.

With the RCS average temperature above 200°F, a minimum of two boron injection flow paths are required to ensure single functional capability in the event an assumed failure renders one of the flow paths inoperable. One flow path from the charging pump discharge is acceptable since the flow path components subject to an active failure are upstream of the charging pumps.

The boration flow path specification allows the RWST and the boric acid storage tank to be the boron sources. Due to the lower boron concentration in the RWST, borating the RCS from this source is less effective than borating from the boric acid tank and additional time may be required to achieve the desired SHUTDOWN MARGIN required by ACTION statement restrictions. ACTION times allow for an orderly sequential shutdown of both units when the inoperability of a component(s) affects both units with equal severity. When a single unit is affected, the time to be in HOT STANDBY is 6 hours. When an ACTION statement requires a dual unit shutdown, the time to be in HOT STANDBY is 12 hours.

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TECHNICAL SPECIFICATION BASES

3/4.1 REACTIVITY CONTROL SYSTEMS (Continued)

3/4.1.2 BORATION BORATION SYSTEMS (Continued)

The ACTION statement restrictions for the boration flow paths allow continued operation in mode 1 for a limited time period with either boration source flow path or the normal flow path to the RCS (via the regenerative heat exchanger) inoperable. In this case, the plant capability to borate and charge into the RCS is limited and the potential operational impact of this limitation on mode 1 operation must be addressed. With both the flow path from the boric acid tanks and the regenerative heat exchanger flow path inoperable, immediate initiation of action to go to COLD SHUTDOWN is required but no time is specified for the mode reduction due to the reduced plant capability with these flow paths inoperable.

Two charging pumps are required to be OPERABLE to ensure single functional capability in the event an assumed failure renders one of the pumps or power supplies inoperable. Each bus supplying the pumps can be fed from either the Emergency Diesel Generator or the offsite grid through a startup transformer.

The boration capability of either flow path is sufficient to provide the required SHUTDOWN MARGIN in accordance with Figure 3.1-1 from expected operating conditions after xenon decay and cooldown to 200°F. The maximum expected boration capability requirement occurs at EOL peak xenon conditions without letdown such that boration occurs only during the makeup provided for coolant contraction. This requirement can be met for a range of boric acid concentrations in the boric acid tank and the refueling water storage tank. The range of boric acid tanks requirements is defined by Technical Specification 3.1.2.5.

With the RCS temperature below 200°F, one boron injection source flow path is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity changes in the event the single boron injection system source flow path becomes inoperable.

The boron capability required below 200°F is sufficient to provide a SHUTDOWN MARGIN of 1% $\Delta k/k$ after xenon decay and cooldown from 200°F to 140°F. This condition requires either 2,900 gallons of at least 3.0 wt% (5245 ppm) borated water per unit from the boric acid storage tanks or 20,000 gallons of 1950 ppm borated water from the RWST.

The charging pumps are demonstrated to be OPERABLE by testing as required by Section XI of the ASME code or by specific surveillance requirements in the specification. These requirements are adequate to determine OPERABILITY because no safety analysis assumption relating to the charging pump performance is more restrictive than these acceptance criteria for the pumps.

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TECHNICAL SPECIFICATION BASES

3/4.1 REACTIVITY CONTROL SYSTEMS (Continued)

3/4.1.2 BORATION BORATION SYSTEMS (Continued)

The boron concentration of the RWST in conjunction with manual addition of borax ensures that the solution recirculated within containment after a LOCA will be basic. The basic solution minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. The temperature requirements for the RWST are based on the containment integrity and large break LOCA analysis assumptions.

The OPERABILITY of one Boron Injection flowpath during REFUELING ensures that this system is available for reactivity control while in MODE 6. Components within the flowpath, e.g., boric acid transfer pumps or charging pumps, must be capable of being powered by an OPERABLE emergency power source, even if the equipment is not required to operate.

The OPERABILITY requirement of 55°F and corresponding surveillance intervals associated with the boric acid tank system ensures that the solubility of the boron solution will be maintained. The temperature limit of 55°F includes a 5°F margin over the 50°F solubility limit of 3.5 wt.% boric acid. Portable instrumentation may be used to measure the temperature of the rooms containing boric acid sources and flow paths.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that: (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) the potential effects of rod misalignment on associated accident analyses are limited. OPERABILITY of the control rod position indicators is required to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits. OPERABLE condition for the analog rod position indicators is defined as being capable of indicating rod position to within the Allowed Rod Misalignment of Specification 3.1.3.1 of the demand counter position. For the Shutdown Banks and Control Banks A and B, the Position Indication requirement is defined as the group demand counter indicated position between 0 and 30 steps withdrawn inclusive, and between 200 steps withdrawn and All Rods Out (ARO) inclusive. This permits the operator to verify that the control rods in these banks are either fully withdrawn or fully inserted, the normal operating modes for these banks. Knowledge of these bank positions in these two areas satisfies all accident analysis assumptions concerning their position. For Control Banks C and D, the Position Indication requirement is defined as the group demand counter indicated position between 0 steps withdrawn and All Rods Out (ARO) inclusive.

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TECHNICAL SPECIFICATION BASES

3/4.1 REACTIVITY CONTROL SYSTEMS (Continued)

3/4.1.3 MOVABLE CONTROL ASSEMBLIES (Continued)

The increase in the Allowable Rod Misalignment below 90% or Rated Thermal Power is as a result of the increase in the peaking factor limits as reactor power is reduced.

Comparison of the group demand counters to the bank insertion limits with verification of rod position with the analog rod position indicators (after thermal soak after rod motion) is sufficient verification that the control rods are above the insertion limits.

Rod position indication is provided by two methods: a digital count of actuating pulses which shows demand position of the banks and a linear position indicator Linear Variable Differential Transformer which indicates the actual rod position. The relative accuracy of the linear position indicator Linear Variable Differential Transformer is such that, with the most adverse error, an alarm will be actuated if any two rods within a bank deviate by more than 24 steps for rods in motion and 12 steps for rods at rest. Complete rod misalignment (12 feet out of alignment with its bank) does not result in exceeding core limits in steady-state operation at RATED THERMAL POWER. If the condition cannot be readily corrected, the specified reduction in power to 75% will insure that design margins to core limits will be maintained under both steady-state and anticipated transient conditions. The 8-hour permissible limit on rod misalignment is short with respect to the probability of an independent accident.

The ACTION statements which permit limited variations from the basic requirements are accompanied by additional restrictions which ensure that the original design criteria are met. Misalignment of a rod requires measurement of peaking factors and a restriction in THERMAL POWER. These restrictions provide assurance of fuel rod integrity during continued operation. In addition, those safety analyses affected by a misaligned rod are reevaluated to confirm that the results remain valid during future operation.

The maximum rod drop time restriction is consistent with the assumed rod drop time used in the safety analyses. Measurement with Tavg greater than or equal to 500°F and with all reactor coolant pumps operating ensures that the measured drop times will be representative of insertion times experienced during a Reactor trip at operating conditions.

Control rod positions and OPERABILITY of the rod position indicators are required to be verified on a nominal basis of once per 12 hours with more frequent verifications required if an automatic monitoring channel is inoperable. These verification frequencies are adequate for assuring that the applicable LCOs are satisfied.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS

The specifications of this section provide assurance of fuel integrity during Condition I (Normal Operation) and II (Incidents of Moderate Frequency) events by: (1) maintaining the minimum DNBR in the core greater than or equal to the applicable design limit during normal operation and in short-term transients, and (2) limiting the fission gas release, fuel pellet temperature, and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the ECCS acceptance criteria limit of 2200°F is not exceeded.

The definitions of certain hot channel and peaking factors as used in these specifications are as follows:

$F_Q(Z)$ Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods;

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power; and

$F_{XY}(Z)$ Radial Peaking Factor, is defined as the ratio of peak power density to average power density in the horizontal plane at core elevation Z.

3/4.2.1 AXIAL FLUX DIFFERENCE

The limits on AXIAL FLUX DIFFERENCE (AFD) assure that the $F_Q(Z)$ limit defined in the CORE OPERATING LIMITS REPORT times the normalized axial peaking factor is not exceeded during either normal operation or in the event of xenon redistribution following power changes.

Target flux difference is determined at equilibrium xenon conditions. The full-length rods may be positioned within the core in accordance with their respective insertion limits and should be inserted near their normal position for steady-state operation at high power levels. The value of the target flux difference obtained under these conditions divided by the fraction of RATED THERMAL POWER is the target flux difference at RATED THERMAL POWER for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RATED THERMAL POWER value by the appropriate fractional THERMAL POWER level. The periodic updating of the target flux difference value is necessary to reflect core burnup considerations.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.1 AXIAL FLUX DIFFERENCE (Continued)

At power level below P_T, the limits on AFD are specified in the CORE OPERATING LIMITS REPORT (COLR) for RAOC operation. These limits were calculated in a manner such that expected operational transients, e.g., load follow operations, would not result in the AFD deviating outside of those limits. However, in the event that such a deviation occurs, a 15 minute period of time allowed outside of the AFD limits at reduced power levels will not result in significant xenon redistribution such that the envelope of peaking factors would change sufficiently to prevent operation in the vicinity of the power level.

With P_T greater than 100%, two modes are permissible: 1) RAOC with fixed AFD limits as a function of reactor power level and 2) Base Load operation which is defined as the maintenance of the AFD within a band about a target value. Both the fixed AFD limits for RAOC operation and the target band for Base Load operation are defined in the COLR and the Peaking Factor Limit Report, respectively. However, it is possible during extended load following maneuvers that the AFD limits may result in restrictions in the maximum allowed power or AFD in order to guarantee operation with $F_Q(Z)$ less than its limiting value. Therefore, P_T is calculated to be less than 100%. To allow operation at the maximum permissible value above P_T Base Load operation restricts the indicated AFD to a relative small target band and power swings. For Base Load operation, it is expected that the plant will operate within the target band. Operation outside of the target band for the short time period allowed (15 minutes) will not result in significant xenon redistribution such that the envelope of peaking factors will change sufficiently to prohibit continued operation in the power region defined above. To assure that there is no residual xenon redistribution impact from past operation on the Base Load operation, a 24-hour waiting period within a defined range of P_T and AFD allowed by RAOC is necessary. During this period, load changes and rod motion are restricted to that allowed by the Base Load requirement. After the waiting period, extended Base Load operation is permissible.

Provisions for monitoring the AFD on an automatic basis are derived from the plant process computer through the AFD Monitoring Alarm. The computer monitors the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels are: 1) outside the acceptable AFD (for RAOC operation), or 2) outside the acceptable AFD target band (for Base Load operation). These alarms are active when power is greater than: 1) 50% of RATED THERMAL POWER (for RAOC operation), or 2) P_T (Base Load operation). Penalty deviation minutes for Base Load operation are not accumulated based on the short time period during which operation outside of the target band is allowed.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

The limits on heat flux hot channel factor and nuclear enthalpy rise hot channel factor ensure that: (1) the design limits on peak local power density and minimum DNBR are not exceeded and (2) in the event of a LOCA the peak fuel clad temperature will not exceed the 2200°F ECCS acceptance criteria limit. The LOCA peak fuel clad temperature limit may be sensitive to the number of steam generator tubes plugged.

$F_Q(Z)$, Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux.

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

Each of these is measurable but will normally only be determined periodically as specified in Specifications 4.2.2 and 4.2.3. This periodic surveillance is sufficient to ensure that the limits are maintained provided:

a. Control rods in a single group move together with no individual rod insertion differing by more than ± 12 steps, indicated, from the group demand position;

b. Control rod groups are sequenced with overlapping groups as described in Specification 3.1.3.6;

c. The control rod insertion limits of Specifications 3.1.3.5 and 3.1.3.6 are maintained; and

d. The axial power distribution, expressed in terms of AXIAL FLUX DIFFERENCE, is maintained within the limits.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

When an F_Q measurement is taken, both experimental error and manufacturing tolerance must be allowed for. Five percent is the appropriate allowance for a full core map taken with the movable incore detector flux mapping system and three percent is the appropriate allowance for manufacturing tolerance. These uncertainties only apply if the map is taken for purposes other than the determination of P_{BL} and P_{RB}.

$F^N_{\Delta H}$ will be maintained within its limits provided Conditions a. through d. above are maintained.

In the specified limit of $F^N_{\Delta H}$ there is an 8 percent allowance for uncertainties which means that normal operation of the core is expected to result in $F^N_{\Delta H} \leq F^{RTP}_{\Delta H}/1.08$, where $F^{RTP}_{\Delta H}$ is the $F^N_{\Delta H}$ limit at RATED THERMAL POWER (RTP) specified in the CORE OPERATING LIMITS REPORT. The logic behind the larger uncertainty in this case is that (a) normal perturbations in the radial power shape (e.g., rod misalignment) affect $F^N_{\Delta H}$, in most cases without necessarily affecting F_Q, (b) although the operator has a direct influence on F_Q through movement of rods, and can limit it to the desired influence on F_Q through movement of rods, and can limit it to the desired value, he has no direct control over $F^N_{\Delta H}$ and (c) an error in the prediction for radial power shape, which may be detected during startup physics tests can be compensated for in F_Q by tighter axial control, bu compensation for $F^N_{\Delta H}$ is less readily available. When a measurement of $F^N_{\Delta H}$ is taken, experimental error must be allowed for and 4% is the appropriate allowance for a full core map taken with the movable incore detector flux mapping system.

The following are independent augmented surveillance methods used to ensure peaking factors are acceptable for continued operation above Threshold Power, P_T:

Base Load - This method uses the following equation to determine peaking factors:

$$F_{QBL} = F_Q(Z) \text{ measured } \times 1.09 \times W(Z)_{BL}$$

where:
$W(Z)_{BL}$ = accounts for power shapes;
1.09 = accounts for uncertainty;
$F_Q(Z)$ = measured data;
F_{QBL} = Base load peaking factor.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

The analytically determined $[F_Q]^P$ is formulated to generate limiting shapes for all load follow maneuvers consistent with control to a ± 5% band about the target flux difference. For Base Load operation the severity of the shapes that need to be considered is significantly reduced relative to load follow operation.

The severity of possible shapes is small due to the restrictions imposed by Sections 4.2.2.3. To quantify the effect of the limiting transients which could occur during Base Load operation, the function $W(Z)_{BL}$ is calculated from the following relationship:

$$W(Z)_{BL} = \text{Max}\left[\frac{F_Q(Z)\ \text{(Base Load Case(s), 150 MWD/T)}}{F_Q(Z)\ \ \text{(ARO, 150 MWD/T)}}, \frac{F_Q(Z)\ \text{(Base Case(s), 85\% EOL BU)}}{F_Q(Z)\ \ \text{(ARO, 85\% BOL BU)}}\right]$$

Radial Burndown - This method uses the following equation to determine peaking factors.

$$F_Q(Z)_{R.B.} = F_{xy}(Z)_{measured} \times F_Z(Z) \times 1.09$$

where: 1.09 = accounts for uncertainty

$F_Z(Z)$ = accounts for axial power shapes

$F_{xy}(Z)_{measured}$ = ratio of peak power density to average power density at elevation(Z)

$F_Q(Z)_{R.B.}$ = Radial Burndown Peaking Factor.

For Radial Burndown operation the full spectrum of possible shapes consistent with control to a ±5% Delta-I band needs to be considered in determining power capability. Accordingly, to quantify the effect of the limiting transients which could occur during Radial Burndown operation, the function $F_Z(Z)$ is calculated from the following relationship:

$$F_Z(Z) = [F_Q(Z)]\ \text{FAC Analysis}/[F_{xy}(Z)]\ \text{ARO}$$

TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

The essence of the procedure is to maintain the xenon distribution in the core as close to the equilibrium full power condition as possible. This can be accomplished by using the boron system to position the full length control rods to produce the require indicated flux difference.

Above the power level of P_T, additional flux shape monitoring is required. In order to assure that the total power peaking factor, F_Q, is maintained at or below the limiting value, the movable incore instrumentation will be utilized. Thimbles are selected initially during startup physics tests so that the measurements are representative of the peak core power density. By limiting the core average axial power distribution, the total power peaking factor F_Q can be limited since all other components remain relatively; fixed. The remaining part of the total power peaking factor can be derived from incore measurements, i.e., an effective radial peaking factor $\overline{R}$, can be determined as the ratio of the total peaking factor resulting from a full core flux map and the axial peaking factor in a selected thimble.

The limiting value of $[F_j\,(Z)]_S$ is derived as follows:

$$[F_j\,(Z)]_S = \frac{[F_Q]^L \times [K(Z)]}{P_L \overline{R}_j\,(1+\sigma_j)\,(1.03)\,(1.07)}$$

Where:

a) $F_j\,(Z)$ is the normalized axial power distribution from thimble j at elevation Z.

b) P_L is reactor thermal power expressed as a fraction of 1.

c) K(Z) is the reduction in the F_Q limit as a function of core elevation (Z) as specified in the CORE OPERATING LIMITS REPORT.

d) $[F_j\,(Z)]_s$ is the alarm setpoint for MIDS.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

e) R_j, for thimble j, is determined from n=6 incore flux maps covering the full configuration of permissible rod patterns at the thermal power limit of P_T.

$$\bar{R}_j = \frac{\sum_{i=1}^{n} R_{ij}}{n}$$

where

$$R_{ij} = \frac{F_{Qi}\ \text{meas.}}{[F_{ij}\ (Z)]\ \text{max}}$$

and F_{ij} (Z) is the normalized axial distribution at elevation Z from thimble j in map i which has a measure peaking factor without uncertainties or densification allowance of F_{Qi} meas.

f) σ_j is the standard deviation, expressed as a fraction or percentage of $\bar{R}_j$, and is derived from n flux maps and the relationship below, or 0.02 (2%), whichever is greater.

$$\sigma_j = \left[\frac{\frac{1}{n-1}\sum_{i-1}^{n}(R_{ij} - \bar{R}_j)^2}{\bar{R}_j}\right]^{1/2}$$

g) The factor 1.03 reduction in the kw/ft limit is the engineering uncertainty factor.

h) The factors (1+ σ_j) and 1.07 represent the margin between $(F_j(Z)]_L$ limit and the MIDS alarm setpoint $[F_j(Z)]_s$. Since (1 +σ_j) is bounded by a lower limit of 1.02, there is at least a 9% reduction of the alarm setpoint. Operations are permitted in excess of the operational limit ≤ 4% while making power adjustment on a percent for percent basis.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.4 QUADRANT POWER TILT RATIO

The QUADRANT POWER TILT RATIO limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during STARTUP testing and periodically during power operation.

The limit of 1.02, at which corrective action is required, provides DNB and linear heat generation rate protection with x-y plane power tilts. A limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The 2-hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned control rod. In the event such action does not correct the tilt, the margin for uncertainty on $F_Q(Z)$ is reinstated by reducing the maximum allowed power by 3% for each percent of tilt in excess of 1.

For purposes of monitoring QUADRANT POWER TILT RATIO when one excore detector is inoperable, the movable incore detectors or incore thermocouple map are used to confirm that the normalized symmetric power distribution is consistent with the QUADRANT POWER TILT RATIO. The incore detector monitoring is done with a full incore flux map or two sets of four symmetric thimbles. The two sets of four symmetric thimbles is a unique set of eight detector locations. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, N-8.

3/4.2.5 DNB PARAMETERS

The limits on the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial FSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR above the applicable design limits throughout each analyzed transient. The indicated Tavg value of 581.2°F and the indicated pressurizer pressure value of 2200 psig correspond to analytical limits of 583.2°F and 2175 psig respectively, with allowance for measurement uncertainty.

The measured RCS flow value of 264,000 gpm corresponds to an analytical limit of 255,000 gpm which is assumed to have a 3.5% calorimetric measurement uncertainty.

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TECHNICAL SPECIFICATION BASES

3/4.2 POWER DISTRIBUTION LIMITS (Continued)

3/4.2.5 DNB PARAMETERS (Continued)

The 12-hour periodic surveillance of these parameters through instrument readout is sufficient to ensure that the parameters are restored within their limits following load changes and other expected transient operation. The 18-month periodic measurement of the RCS total flow rate is adequate to ensure that the DNB-related flow assumption is met and to ensure correlation of the flow indication channels with measured flow. Six month drift effects have been included for feedwater temperature, feedwater flow, steam pressure, and the pressurizer pressure inputs. The flow measurement is performed within ninety days of completing the cross-calibration of the hot leg and cold leg narrow range RTDs. The indicated percent flow surveillance on a 12-hour basis will provide sufficient verification that flow degradation has not occurred. An indicated percent flow which is greater than the thermal design flow plus instrument channel inaccuracies and parallax errors is acceptable for the 12 hour surveillance on RCS flow. To minimize measurement uncertainties it is assumed that the RCS flow channel outputs are averaged.

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TECHNICAL SPECIFICATION BASES

3/4.3 INSTRUMENTATION

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

The OPERABILITY of the Reactor Trip System and the Engineered Safety Features Actuation System instrumentation and interlocks ensures that: (1) the associated ACTION and/or Reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its Setpoint (2) the specified coincidence logic is maintained, (3) sufficient redundancy is maintained to permit a channel to be out-of-service for testing or maintenance (due to plant specific design, pulling fuses and using jumpers may be used to place channels in trip), and (4) sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy, and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the safety analyses. The Surveillance Requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability. Surveillances for the analog RPS/ESFAS Hagan rack instrumentation have been extended to quarterly in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and supplements to that report as generically approved by the NRC and documented in their SERs (Letters to the Westinghouse Owner's Group from the NRC dated February 21, 1985, February 22, 1989, and April 30, 1990).

Under some pressure and temperature conditions, certain surveillances for Safety Injection cannot be performed because of the system design. Allowance to change modes is provided under these conditions as long as the surveillances are completed within specified time requirements.

The Engineered Safety Features Actuation System Instrumentation Trip Setpoints specified in Table 3.3-3 are the nominal values at which the bistables are set for each functional unit. The setpoint is considered to be adjusted consistent with the Nominal Trip Setpoint when the "as measured" setpoint is within the band allowed for calibration accuracy. Although the degraded voltage channel for Item 7.c consists of definite time (ITE) and inverse time (IAV) relays, the setpoint specified in Table 3.3-3 is only applicable to the definite time delay relays (Reference: CR 00-2301). The original protection scheme consisted of inverse time voltage relays; but based on operational experience, it was found that the settings of these relays drifted in a non-conservative direction. In 1992, to improve repeatability and to reduce potential harmful effects due to setpoint drifts, ITE definite time delay relays were added to the protection scheme to protect the 480 V alternating current (AC) system from adverse effects of a

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.3 INSTRUMENTATION (Continued)

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

sustained degraded voltage condition. The IAV relays protect the system from adverse effects of a brief large voltage transient. The IAV relay settings are such that they should not operate before the ITE relays. The degraded voltage protection is ensured by the definite time delay relays with the setpoints specified in the TS Table 3.3-3, Item 7.c (References: L-92-097 dated 4/21/92, and L-92-215 dated 7/29/92). These changes were approved by NRC letter dated August 20, 1992, and implemented by Amendment Nos 152 and 147.

To accommodate the instrument drift that may occur between operational tests and the accuracy to which setpoints can be measured and calibrated, statistical allowances are provided for in the Nominal Trip Setpoint and Allowable Values in accordance with the setpoint methodology described in WCAPs 12201 and 12745. Surveillance criteria have been determined and are controlled in Plant procedures and in design documents. The surveillance criteria ensure that instruments which are not operating within the assumptions of the setpoint calculations are identified. An instrument channel is considered OPERABLE when the surveillance is within the Allowable Value and the channel is capable of being calibrated in accordance with Plant procedures. Sensor and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes.

The inability to demonstrate through measurement and/or analytical means, using the methods described in WCAPs 12201 and 12745 (TA $\geq$R+S+Z), that the Reactor Trip function would have occurred within the values specified in the design documentation provides a threshold value for REPORTABLE EVENTS.

There is a small statistical probability that a properly functioning device will drift beyond determined surveillance criteria. Infrequent drift outside the surveillance criteria are expected. Excessive rack or sensor drift that is more than occasional, may be indicative of more serious problems and should warrant further investigations.

The Engineered Safety Features Actuation System senses selected plant parameters and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents events, and transients. Once the required logic combination is completed, the system sends actuation signals to

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.3 INSTRUMENTATION (Continued)

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

those Engineered Safety Features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the Engineered Safety Features Actuation System to mitigate the consequences of a steam line break or loss-of-coolant accident: (1) Safety Injection pumps start and automatic valves position, (2) Reactor trip, (3) feed water isolation, (4) startup of the emergency diesel generators, (5) containment spray pumps start and automatic valves position (6) containment ventilation isolation, (7) steam line isolation, (8) turbine trip, (9) auxiliary feedwater pumps start and automatic valves position, (10) containment cooling fans start and automatic valves position, (11) intake cooling water and component cooling water pumps start and automatic valves position, and (12) Control Room Isolation and Ventilation Systems start. This system also provides a feedwater system isolation to prevent SG overfill. Steam Generator overfill protection is not part of the Engineered Safety Features Actuation System (ESFAS), and is added to the Technical Specifications only in accordance with NRC Generic Letter 89-19.

Item 5 of Table 3.3-2 requires that two trains of feedwater isolation actuation logic and relays be OPERABLE in Modes 1 and 2. Operability requires:

a) isolation of both the normal feedwater branch and the bypass branch lines during a safety injection actuation signal or high-high steam generator water level signal, and

b) two independent trains of automatic actuation logic and actuation relays.

In the event that maintenance and/or in-service testing is required on a feedwater regulating valve in Mode 1 or 2, the above requirements can be met by closing the isolation valve upstream of the affected feedwater regulating valve, administratively controlling the position of the isolation valve, and controlling feedwater flow with an OPERABLE feedwater regulating valve (main or bypass).

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TECHNICAL SPECIFICATION BASES

3/4.3 INSTRUMENTATION (Continued)

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

When complying with ACTION 23 for Table 3.3-2 Functional Unit 6.d. the plant does not enter Limiting Condition for Operation (LCO) 3.0.3. ACTION 23, in the wording "comply with Specification 3.0.3", requires actions to be taken that are the same as those described in LCO 3.0.3, without any requirement to enter LCO 3.0.3. ACTION 23 has designated conditions under which the specific prescribed ACTIONS of "within 1 hour action shall be initiated to place the unit, as applicable, in:

a. At least HOT STANDBY within the next 6 hours,
b. At least HOT SHUTDOWN within the following 6 hours, and
c. At least COLD SHUTDOWN within the subsequent 24 hours,"

These are required when the designated conditions of "the number of OPERABLE channels one less than the Minimum Channels OPERABLE," are not met.

The definition of ACTION in Technical Specifications Section 1.1 is "that part of a Technical Specification which prescribes remedial measures required under designated conditions." The TS Bases for 3.0.3 describe the fact that 3.0.3 establishes the shutdown ACTION requirements that must be implemented when a Limiting Condition for Operation is not met and the condition is not specifically addressed by the associated ACTION requirements." In the case of ACTION statement 23, shutdown ACTION requirements are specifically described in the ACTION statement as inferred in the wording "comply with Specification 3.0.3." No reporting is necessary under ACTION 23 until a shutdown is begun.

The Engineered Safety Features Actuation System interlocks perform the following functions:

HIGH STEAM FLOW SAFETY INJECTION BLOCK - This permissive is used to block the safety injection (SI) signal generated by High Steam Line Flow coincident with Low Steam Line Pressure or Low T_{avg}. The permissive is generated when two out of three Low T_{avg} channels drop below their setpoints and the manual SI Block/Unblock switch is momentarily placed in the block position. This switch is a spring return to the normal position type. The permissive will automatically be defeated if two out of three Low T_{avg} channels rise above their setpoints. The permissive may be manually defeated when two out of three Low T_{avg} channels are below their setpoints and the manual SI Block/Unblock switch is momentarily placed in the unblock position.

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TECHNICAL SPECIFICATION BASES

3/4.3 INSTRUMENTATION (Continued)

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM AND ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

LOW PRESSURIZER PRESSURE SAFETY INJECTION BLOCK - This permissive is used to block the safety injection signals generated by Low Pressurizer Pressure and High Differential Pressure between the Steam Line Header and any Steam Line. The permissive is generated when two out of three pressurizer pressure permissive channels drop below their setpoints and the manual SI Block/Unblock switch is momentarily placed in the block position. This is the same switch that is used to manually block the High Steam Flow Safety Injection signals mentioned above. This permissive will automatically be defeated if two out of three pressurizer pressure permissive channels rise above their setpoints. The permissive may be manually defeated when two out of three pressurizer pressure permissive channels are below their setpoints and the manual SI Block/Unblock switch momentarily placed in the Unblock position.

3/4.3.3 MONITORING INSTRUMENTATION

3/4.3.3.1 RADIATION MONITORING FOR PLANT OPERATIONS

The OPERABILITY of the radiation monitoring instrumentation for plant operations ensures that conditions indicative of potential uncontrolled radioactive releases are monitored and that appropriate actions will be automatically or manually initiated when the radiation level monitored by each channel reaches its alarm or trip setpoint.

3/4.3.3.2 MOVABLE INCORE DETECTORS

The OPERABILITY of the movable incore detectors with the specified minimum complement of equipment ensures that the measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core. The OPERABILITY of this system is demonstrated by irradiating each detector used and determining the acceptability of its voltage curve.

For the purpose of measuring $F_Q(Z)$ or $F_{\Delta H}^N$ a full incore flux map is used. Quarter-core flux maps, as defined in WCAP-8648, June 1976 or in the Westinghouse Single Point Calibration Technique, may be used in recalibration of the Excore Neutron Flux Detection System, and full incore flux maps or symmetric incore thimbles may be used for monitoring the QUADRANT POWER TILT RATIO when one Power Range channel is inoperable.

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TECHNICAL SPECIFICATION BASES

3/4.3 INSTRUMENTATION (Continued)

3/4.3.3.3 ACCIDENT MONITORING INSTRUMENTATION

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables following an accident. This capability is consistent with the recommendations of Regulatory Guide 1.97, Revision 3, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident," May 1983 and NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

TS Table 3.3-5, Accident Monitoring Instrumentation, instrument item 3, Reactor Coolant Outlet Temperature, T-hot and instrument item 4 Reactor Coolant Inlet Temperature, T-cold, utilize the terms “detector” and “channel”. The term channel (in the context of the specification) refers to one of the two channels of QSPDS. Each channel has three detectors as inputs, one from each loop. For example, Resistance Temperature Detectors TE-3-413A, TE-3-423A, and TE-3-433A are the three detectors which feed QSPDS Channel A for Unit 3. The TOTAL NUMBER OF CHANNELS is two (with two of the three detectors required). The MINIMUM CHANNELS OPERABLE is one (with two of the three detectors.) To call a channel operable, it must have at least two of its three detectors operable. Although the minimum channels operable is one (of two), having one channel inoperable invokes Action Statement 31 (restore in seven days or shut down).

The QSPDS is configured into two channels, but it is often referred to as having two “trains”. In general, the term “train” applies only to Reactor Protection System (RPS) / Engineering Safety Feature Actuation System (ESFAS) actuation signals, i.e., there are two trains of reactor protection; each train will trip one reactor trip breaker. “Train” is not appropriate to QSPDS, since QSPDS serves no automatic protection function.

Technical Specification Table 3.3-5, Item 14.1, Incore Thermocouples (Core Exit Thermocouples), utilizes the term channel. There are no "channels" of Incore Thermocouples as stated previously, the term Channel refers to one of the two QSPDS channels. NUREG 0737, Section II.F.2, Attachment 1, Item (3) describes what is required from instrumentation standpoint: "A...display...should be provided with the capability for selective reading of a minimum of 16 operable thermocouples, 4 from each core quadrant...." This description is the basis for our Technical Specification, and clarifies the requirement for Incore Thermocouples. If we have fewer than 4 thermocouples per core quadrant, Action 31 applies. If we have fewer than 2 thermocouples per quadrant, Action 32 applies. There is no regulatory requirement that these 2 or 4 thermocouples per core quadrant be assigned to or divided between the two channels of QSPDS. The column heading "TOTAL NO. OF CHANNELS," is also misleading for the Incore Thermocouples. There are more than 4 thermocouples in every core quadrant. It takes 4 thermocouples per core quadrant to satisfy the Technical Specifications and unrestricted operation with fewer than the "TOTAL" but at least the "MINIMUM" is not allowed. For example, if there are only 3 operable thermocouples in a quadrant, in 7 days one must be fixed or shut down.

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TECHNICAL SPECIFICATION BASES

3/4.3 INSTRUMENTATION (Continued)

3/4.3.3.4 FIRE DETECTION INSTRUMENTATION - (Deleted)

3/4.3.3.5 RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

The radioactive liquid effluent instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in liquid effluents during actual or potential releases of liquid effluents. The Alarm/Trip Setpoints for these instruments shall be calculated and adjusted in accordance with the methodology and parameters in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63, and 64 of Appendix A to 10 CFR Part 50.

3/4.3.3.6 RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

The radioactive gaseous effluent instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in gaseous effluents during actual or potential releases of gaseous effluents. The Alarm/Trip Setpoints for these instruments shall be calculated and adjusted in accordance with the methodology and parameters in the ODCM to ensure that the alarm/trip will occur prior to exceeding the limits of 10 CFR Part 20. This instrumentation also includes provisions for monitoring (and controlling) the concentrations of potentially explosive gas mixtures in the GAS DECAY TANK SYSTEM. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63, and 64 of Appendix A to 10 CFR Part 50. The sensitivity of any noble gas activity monitors used to show compliance with the gaseous effluent release requirements of Specification 3.11.2.2 shall be such that concentrations as low as 1×10^{-6} μCi/ml are measurable.

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with all reactor coolant loops in operation and maintain DNBR above the applicable design limit during all normal operations and anticipated transients. In MODES 1 and 2 with one reactor coolant loop not in operation this specification requires that the plant be in at least HOT STANDBY within 6 hours.

In MODE 3, three reactor coolant loops provide sufficient heat removal capability for removing core decay heat in the event of a bank withdrawal accident; however, a single reactor coolant loop provides sufficient heat removal capacity if a bank withdrawal accident can be prevented, i.e., by opening the Reactor Trip System breakers. Single active failure considerations require that at least two loops be OPERABLE at all times.

In MODE 4, and in MODE 5 with reactor coolant loops filled, a single reactor coolant loop or RHR loop provides sufficient heat removal capability for removing decay heat, but all combinations of two loops, except two RHR loops, provide single active failure protection.

In MODE 5 with reactor coolant loops not filled, a single RHR loop provides sufficient heat removal capability for removing decay heat; but the unavailability of the steam generators as a heat removing component, requires that at least two RHR loops be OPERABLE.

To take credit for reactor coolant loops being filled requires the availability of at least two steam generators as heat removing components. Then if the RHR loop is lost, natural circulation will be established. If the RCS is depressurized, natural circulation cannot be established since there is not enough thermal driving head that can be established to overcome the Steam Generator U-tube voids. Therefore loops shall not be considered filled unless the reactor coolant system has been filled and vented with no intervening evolutions that could introduce air into the steam generators, and is pressurized to at least 100 psig (JPN-PTN-SEMS-95-026). The RCS loops cannot be considered a valid coolant loop if the RCS is depressurized to less than 100 psig, and two RHR loops must be OPERABLE.

The operation of one reactor coolant pump (RCP) or one RHR pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reduction will, therefore, be within the capability of operator recognition and control.

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION (Continued)

The restrictions on starting an RCP with one or more RCS cold legs less than or equal to 275°F are provided to prevent RCS pressure transients, caused by energy additions from the Secondary Coolant System, which could exceed the limits of Appendix G to 10 CFR Part 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by either: (1) restricting the water volume in the pressurizer and thereby providing a volume for the reactor coolant to expand into, or (2) by restricting starting of the RCPs to when the secondary water temperature of each steam generator is less than 50°F above each of the RCS cold leg temperatures. The 50°F limit includes instrument error.

The Technical Specifications for Cold Shutdown allow an inoperable RHR pump to be the operating RHR pump for up to 2 hours for surveillance testing to establish operability. This is required because of the piping arrangement when the RHR system is being used for Decay Heat Removal.

3/4.4.2 SAFETY VALVES

The pressurizer Code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 293,330 lbs per hour of saturated steam at the valve Setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an RCS vent opening of at least 2.50 square inches will provide overpressure relief capability and will prevent RCS overpressurization. In addition, the Overpressure Mitigating System provides a diverse means of protection against RCS overpressurization at low temperatures.

During operation, all pressurizer Code safety valves must be OPERABLE to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. The combined relief capacity of all of these valves is greater than the maximum surge rate resulting from a complete loss-of-load assuming no Reactor trip until the first Reactor Trip System Trip Setpoint is reached (i.e., no credit is taken for a direct Reactor trip on the loss-of-load) and also assuming no operation of the power-operated relief valves or steam dump valves.

In Mode 5 only one pressurizer code safety is required for overpressure protection. In lieu of an actual operable code safety valve, an unisolated and unsealed vent pathway (i.e., a direct, unimpaired opening, a vent pathway with valves locked open and/or power removed and locked on an open valve) of equivalent size can be taken credit for as synonymous with an OPERABLE code safety.

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.2 SAFETY VALVES (Continued)

Demonstration of the safety valves' lift settings will occur only during shutdown and will be performed in accordance with the provisions of Section XI of the ASME Boiler and Pressure Code. The pressurizer code safety valves' lift settings allows a +2%, -3% setpoint tolerance for OPERABILITY; however, the valves are reset to within ±1% during the surveillance to allow for drift.

3/4.4.3 PRESSURIZER

The 12-hour periodic surveillance is sufficient to ensure that the maximum water volume parameter is restored to within its limit following expected transient operation. The maximum water volume (1133 cubic feet) ensures that a steam bubble is formed and thus the RCS is not a hydraulically solid system. The requirement that both backup pressurizer heater groups be OPERABLE enhances the capability of the plant to control Reactor Coolant System pressure and establish natural circulation.

3/4.4.4 RELIEF VALVES

The opening of the power-operated relief valves (PORVs) fulfills no safety-related function and no credit is taken for their operation in the safety analysis for MODE 1, 2 or 3. Equipment necessary to establish PORV operability in Modes 1 and 2 is limited to Vital DC power and the Instrument Air system. Equipment necessary to establish block valve operability is limited to an AC power source. Each PORV has a remotely operated block valve to provide a positive shutoff capability should a PORV fail in the open position.

The OPERABILITY of the PORVs and block valves is determined on the basis of their being capable of performing the following functions:

A. Manual control of PORVs to control reactor coolant system pressure. This is a function that is used as a back-up for the steam generator tube rupture and to support plant shutdown in the event of an Appendix R fire. These functions are considered to be important-to-safety, or Quality Related per the FPL Quality Assurance program.

B. Maintaining the integrity of the reactor coolant pressure boundary. This is a function that is related to controlling identified leakage and ensuring the ability to detect unidentified reactor coolant pressure boundary leakage.

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.4 RELIEF VALVES (Continued)

C. Manual control of the block valve to: (1) unblock an isolated PORV to allow it to be used for manual control of reactor coolant system pressure, and (2) isolate a PORV with excessive leakage.

D. Manual control of a block valve to isolate a stuck-open PORV.

E. Ability to open or close the valve(s), consistent with the required function of the valve(s).

The PORVs are also used to provide automatic pressure control in order to reduce the challenges to the RCS code safety valves for overpresurization events. (The PORVs are not credited in the overpressure accident analyses as noted above.)

Surveillance Requirements provide the assurance that the PORVs and block valves can perform their functions. Specification 4.0.5. is applicable to PORVs and block valves. Specification 4.4.4. also addresses block valves. The block valves are exempt from the surveillance requirements to cycle the valves when they have been closed to comply with the ACTION requirements.

This precludes the need to cycle the valves with full system differential pressure, or when maintenance is being performed to restore an inoperable PORV to operable status.

ACTION statement a. includes the requirement to maintain power to closed block valves because removal of power would render block valves inoperable, with respect to their ability to be reopened in a timely manner to support decay heat removal or depressurization through the PORVs, and the requirements of ACTION statement c. would apply. Power is maintained to the block valve(s) so that it is operable and may be opened subsequently to allow use of the PORV for reactor pressure control or decay heat removal by using feed and bleed. Closure of the block valve(s) establishes reactor coolant pressure boundary integrity in the case of a PORV with excess leakage or for bonnet or stem leakage on the PORV or block valve which is isolable. (Reactor coolant pressure boundary integrity takes priority over the capability of the PORV to mitigate an overpressure event.) However, the APPLICABILITY requirements of the Limiting Condition for Operation (LCO) to operate with the block valve(s) closed with power maintained to the block valve(s) are intended only to permit operation of the plant for a limited period of time not to exceed the next refueling outage (MODE 6) so that maintenance can be performed to eliminate the leakage condition.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM

3/4.4.4 RELIEF VALVES (Continued)

ACTION statements b. and c. include removal of power from a closed block valve as additional assurance against inadvertent opening of the block valve at a time in which the PORV is inoperable for causes other than excessive seat leakage. (In contrast, ACTION statement a. is intended to permit continued plant operation for a limited period with the block valves closed, i.e., continued operation is not dependent on maintenance at power to eliminate excessive PORV leakage. Therefore, ACTION statement a. does not require removal of power from the block valve.)

ACTION statement d. establishes remedial measures consistent with the function of block valves. The most important reason for the capability to close the block valve is to isolate a stuck-open PORV. Therefore, if the block valve(s) cannot be restored to operable status within 1 hour, the remedial action is to place the PORV in manual control to preclude its automatic opening for an overpressure event, and thus avoid the potential for a stuck-open PORV at a time when the block valve is inoperable. The time allowed to restore the block valve(s) to operable status is based upon the remedial action time limits for inoperable PORVs per ACTION statements b. and c. These actions are also consistent with the use of the PORVs to control reactor coolant system pressure if the block valves are inoperable at a time when they have been closed to isolate PORVs with excessive leakage.

Leakage sufficient to cause the RCS total IDENTIFIED LEAKAGE to exceed 10 GPM is excessive, rendering the affected PORV inoperable. With PORV leakage identified, but small enough that it does not cause RCS total IDENTIFIED LEAKAGE to exceed 10 GPM, the PORV is not inoperable because of excessive leakage. The PORV may still be isolated as a matter of prudence but this is an operational decision, not a regulatory requirement. Closing the block valve does not render either the block valve or the PORV inoperable. The block valve is already performing its intended function. The PORV is still capable of relieving RCS pressure. This function is used as a backup for the steam generator tube rupture, and to support plant shutdown in the event of an Appendix R fire.

Surveillance Requirement 4.4.4 states that the block valve surveillance is not required if the block valve is closed to provide an isolation function. This exemption only applies when the block valve has been closed to comply with the ACTION requirements. If the PORV is declared inoperable due to excessive leakage, then the block valve must be closed to comply with ACTION a. Block valve surveillance is not required. If the PORV has not been declared inoperable, but the block valve has been closed as a matter of prudence, then the block valve has not been closed to comply with an ACTION requirement, and the surveillance must still be performed.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.5 STEAM GENERATORS

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or inservice conditions that lead to corrosion. Inservice inspection of steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the limitation of steam generator tube leakage between the Reactor Coolant System and the Secondary Coolant System (reactor-to-secondary leakage = 500 gallons per day per steam generator). Cracks having a reactor-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that reactor-to-secondary leakage of 500 gallons per day per steam generator can readily be detected by radiation monitors of steam generator blowdown. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged.

Wastage-type defects are unlikely with the all volatile treatment (AVT) of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging will be required for all tubes with imperfections exceeding the plugging limit of 40% of the tube nominal wall thickness. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20% of the original tube wall thickness.

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.5 STEAM GENERATORS (Continued)

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be promptly reported to the Commission in a Special Report pursuant to Specification 6.9.2 within 30 days and prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.6.1 LEAKAGE DETECTION SYSTEMS

The RCS Leakage Detection Systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary to the containment. The containment sump level system is the normal sump level instrumentation. The Post Accident Containment Water Level Monitor - Narrow range instrumentation also functions as a sump level monitoring system. In addition, gross leakage will be detected by changes in makeup water requirements, visual inspection, and audible detection. Leakage to other systems will be detected by activity changes (e.g., within the component cooling system) or water inventory changes (e.g., tank levels).

3/4.4.6.2 OPERATIONAL LEAKAGE

PRESSURE BOUNDARY LEAKAGE of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any PRESSURE BOUNDARY LEAKAGE requires the unit to be promptly placed in COLD SHUTDOWN.

Industry experience has shown that while a limited amount of leakage is expected from the RCS, the unidentified portion of this leakage can be reduced to a threshold value of less than 1 gpm. This threshold value is sufficiently low to ensure early detection of additional leakage.

The total steam generator tube leakage limit of 1 gpm for all steam generators ensures that the dosage contribution from the tube leakage will be limited to a small fraction of 10 CFR Part 100 dose guideline values in the event of either a steam generator tube rupture or steam line break. The 500 gpd leakage limit per steam generator ensures that steam generator tube integrity is maintained in the event of a main steam line rupture or under LOCA conditions.

The 10 gpm IDENTIFIED LEAKAGE limitation provides allowance for a limited amount of leakage from known sources whose presence will not interfere with the detection of UNIDENTIFIED LEAKAGE by the Leakage Detection Systems.

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.6.2 OPERATIONAL LEAKAGE (Continued)

The leakage from any RCS pressure isolation valve is sufficiently low to ensure early detection of possible in-series valve failure. It is apparent that when pressure isolation is provided by two in-series valves and when failure of one valve in the pair can go undetected for a substantial length of time, verification of valve integrity is required. Since these valves are important in preventing overpressurization and rupture of the ECCS low pressure piping which could result in a LOCA, these valves should be tested periodically to ensure low probability of gross failure.

The Surveillance Requirements for RCS pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the RCS pressure isolation valve is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

3/4.4.7 CHEMISTRY

The limitations on Reactor Coolant System chemistry ensure that corrosion of the Reactor Coolant System is minimized and reduces the potential for Reactor Coolant System leakage or failure due to stress corrosion. Maintaining the chemistry within the Steady-State Limits provides adequate corrosion protection to ensure the structural integrity of the Reactor Coolant System over the life of the plant. The associated effects of exceeding the oxygen, chloride, and fluoride limits are time and temperature dependent. Corrosion studies show that operation may be continued with contaminant concentration levels in excess of the Steady-State Limits, up to the Transient Limits, for the specified limited time intervals without having a significant effect on the structural integrity of the Reactor Coolant System. The time interval permitting continued operation within the restrictions of the Transient Limits provides time for taking corrective actions to restore the contaminant concentrations to within the Steady-State Limits.

The Surveillance Requirements provide adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action.

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.8 SPECIFIC ACTIVITY

The limitations on the specific activity of the reactor coolant ensure that the resulting 2-hour doses at the SITE BOUNDARY will not exceed an appropriately small fraction of 10 CFR Part 100 dose guideline values following a steam generator tube rupture accident in conjunction with an assumed steady-state reactor-to-secondary steam generator leakage rate of 1 gpm. The values for the limits on specific activity represent limits based upon a parametric evaluation by the NRC of typical site locations. These values are conservative in that specific site parameters of the Turkey Point site, Units 3 and 4 site, such as SITE BOUNDARY location and meteorological conditions, were not considered in this evaluation.

The ACTION statement permitting POWER OPERATION to continue for limited time periods with the reactor coolant's specific activity greater than 1 microCurie/gram DOSE EQUIVALENT I-131, but within the allowable limit shown on Figure 3.4-1, accommodates possible iodine spiking phenomenon which may occur following changes in THERMAL POWER.

The sample analysis for determining the gross specific activity and $\bar{E}$ can exclude the radioiodines because of the low reactor coolant limit of 1 microCurie/gram DOSE EQUIVALENT I–131, and because, if the limit is exceeded, the radioiodine level is to be determined every 4 hours. If the gross specific activity level and radioiodine level in the reactor coolant were at their limits, the radioiodine contribution would be approximately 1%. In a release of reactor coolant with a typical mixture of radioactivity, the actual radioiodine contribution would probably be about 20%. The exclusion of radionuclides with half-lives less than 30 minutes from these determinations has been made for several reasons. The first consideration is the difficulty to identify short-lived radionuclides in a sample that requires a significant time to collect, transport, and analyze. The second consideration is the predictable delay time between the postulated release of radioactivity from the reactor coolant to its release to the environment and transport to the SITE BOUNDARY, which is relatable to at least 30 minutes decay time. The choice of 30 minutes for the half-life cutoff was made because of the nuclear characteristics of the typical reactor coolant radioactivity.

Based upon the above considerations for excluding certain radionuclides from the sample analysis, the allowable time of 2 hours between sample taking and completing the initial analysis is based upon a typical time necessary to perform the sampling, transport the sample, and perform the analysis of about 90 minutes. After 90 minutes, the gross count should be made in a reproducible geometry of sample and counter having reproducible beta or gamma self-shielding properties. The counter should be reset to a reproducible efficiency versus energy. It is not necessary to identify specific nuclides. The radiochemical determination of nuclides should be based on multiple counting of the sample within typical counting basis following sampling of less than 1 hour, about 2 hours, about 1 day, about 1 week, and about 1 month.

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TECHNICAL SPECIFICATION BASES

3/4.4 <u>REACTOR COOLANT SYSTEM</u> (Continued)

3/4.4.8 <u>SPECIFIC ACTIVITY</u> (Continued)

Reducing T_{avg} to less than 500°F prevents the release of activity should a steam generator tube rupture since the saturation pressure of the reactor coolant is below the lift pressure of the atmospheric steam relief valves. The Surveillance Requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

3/4.4.9 <u>PRESSURE/TEMPERATURE LIMITS</u>

All components in the RCS are designed to withstand the effects of cyclic loads due to system temperature and pressure changes. These cyclic loads are induced by normal load transients, reactor trips and startup and shutdown operations. During RCS heatup and cooldown, the temperature and pressure changes must be limited to be consistent with design assumptions and to satisfy stress limits for brittle fracture.

During heatup, the thermal gradients through the reactor vessel wall produce thermal stresses which are compressive at the reactor vessel inside surface and which are tensile at the reactor vessel outside surface. Since reactor vessel internal pressure always produces tensile stresses at both the inside and outside surface locations, the total applied stress is greatest at the outside surface location. However, since neutron irradiation damage is larger at the inside surface location when compared to the outside surface, the inside surface flaw may be more limiting. Consequently for the heatup analysis both the inside and outside surface flaw locations must be analyzed for the specific pressure and thermal loadings to determine which is more limiting.

During cooldown, the thermal gradients through the reactor vessel wall produce thermal stresses which are tensile at the reactor vessel inside surface and which are compressive at the reactor vessel outside surface. Since reactor vessel internal pressure always produces tensile stresses at both the inside and outside surface locations, the total applied stress is greatest at the inside surface location. Since the neutron irradiation damage is also greatest at the inside surface location, the inside surface flaw is the limiting location. Consequently, only the inside surface flaw must be evaluated for the cooldown analysis.

The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G:

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.9 PRESSURE/TEMPERATURE LIMITS (Continued)

1. The reactor coolant temperature and pressure and system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figures 3.4-2 to 3.4-4 for the service period specified thereon:

   a. Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation; and

   b. Figures 3.4-2 to 3.4-4 define limits to assure prevention of non-ductile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity, may limit the heatup and cooldown rates that can be achieved over certain pressure-temperature ranges.

2. These limit lines shall be calculated periodically using methods provided below,

3. The secondary side of the steam generator must not be pressurized above 200 psig if the temperature of the steam generator is below 70°F,

4. The pressurizer heatup and cooldown rates shall not exceed 100°F/h and 200°F/h, respectively. The spray shall not be used if the temperature difference between the pressurizer and the spray fluid is greater than 320°F, and

5. System preservice hydrotests and inservice leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI.

The fracture toughness properties of the ferritic materials in the reactor vessel are determined in accordance with the NRC Standard Review Plan, the version of the ASTM E185 standard required by 10 CFR 50, Appendix H, and in accordance with additional reactor vessel requirements.

The properties are then evaluated in accordance with Appendix G of the 1983 Edition of Section III of the ASME Boiler and Pressure Vessel Code and the additional requirements of 10 CFR 50, Appendix G and the calculation methods described in Westinghouse Report GTSD-A-1.12, "Procedure for Developing Heatup and Cooldown Curves."

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.9 PRESSURE/TEMPERATURE LIMITS (Continued)

Heatup and cooldown limit curves are calculated using the most limiting value of the nil-ductility reference temperature, RT_{NDT}, at the end of 19 effective full power years (EFPY) of service life. The 19 EFPY service life period is chosen such that the limiting RT_{NDT}, at the 1/4T location in the core region is greater than the RT_{NDT}, of the limiting unirradiated material. The selection of such a limiting RT_{NDT} assures that all components in the Reactor Coolant System will be operated conservatively in accordance with applicable Code requirements.

The heatup and cooldown limit curves, Figures 3.4-2, 3.4-3 and 3.4-4 are composite curves prepared by determining the most conservative case with either the inside or outside wall controlling, for any heatup rate up to 100 degrees F per hour and cooldown rates of up to 100 degrees F per hour. The heatup and cooldown curves were prepared based upon the most limiting value of predicted adjusted reference temperature at the end of the applicable service period (19 EFPY).

The reactor vessel materials have been tested to determine their initial RT_{NDT}; the results of these tests are shown in Tables B 3/4.4-1 and B 3/4.4-2. Reactor operation and resultant fast neutron (E greater than 1 MeV) irradiation can cause an increase in the RT_{NDT}. Therefore, an adjusted reference temperature, based upon the fluence and chemistry factors of the material has been predicted using Regulatory Guide 1.99, Revision 2, dated May 1988, "Radiation Embrittlement of Reactor Vessel Materials." The heatup and cooldown limit curves of Figures 3.4-2, 3.4-3, and 3.4-4 include predicted adjustments for this shift in RT_{NDT} at the end of the applicable service period.

The actual shifts in RT_{NDT}, of the vessel materials will be established periodically during operation by removing and evaluating, in accordance with the version of the ASTM E185 standard required by 10 CFR Appendix H, reactor vessel material irradiation surveillance specimens installed near the inside wall of the reactor vessel in the core area. Since the neutron spectra at the irradiation samples and vessel inside radius are essentially identical, the measured transition shift for a sample can be applied with confidence to the adjacent section of the reactor vessel.

Since the limiting beltline materials (Intermediate to Lower Shell Circumferential Weld) in Units 3 and 4 are identical, the RV surveillance program was integrated and the results from capsule testing is applied to both Units. The surveillance capsule "T" results from Unit 3 (WCAP 8631) and Unit 4 (SWRI 02-4221) and the capsule "V" results from Unit 3 (SWRI 06- 8576) were used with the methodology in Regulatory Guide 1.99, Revision 2, to provide limiting material properties information for generating the heatup and cooldown curves in Figures 3.4-2, 3.4-3, and 3.4-4. The integrated surveillance program along with similar identical reactor vessel design and operating characteristics allows the same heatup and cooldown limit curves to be applicable at both Unit 3 and Unit 4.

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TECHNICAL SPECIFICATION BASES

TABLE B 3/4.4-1

REACTOR VESSEL TOUGHNESS (UNIT 3)

Component	Material Type	Cu (%)	Ni (%)	P (%)	NDTT (°F)	50 ft lb/35 mils Lateral Expansion Temp (°F) Long	Trans	RT_{NDT} (°F)	Minimum Upper Shelf (ft lb) Long	Trans
Cl. Hd. Dome	A302 Gr. B	-	-	0.010	0	-	36(a)	0	> 70	> 45.5(a)
Cl. Hd. Flange	A508 Cl. 2	-	0.72	0.010	44(a)	-	31(a)	44	>118	> 76.5(a)
Ves. Sh. Flange	A508 Cl. 2	-	0.65	0.010	-23(a)	-	-41(a)	-23	>120	> 78(a)
Inlet Nozzle	A508 Cl. 2	-	0.76	0.019	60(a)	-	NA	60	NA	NA
Inlet Nozzle	A508 Cl. 2	-	0.74	0.019	60(a)	-	NA	60	NA	NA
Inlet Nozzle	A508 Cl. 2	-	0.80	0.019	60(a)	-	NA	60	NA	NA
Outlet Nozzle	A508 Cl. 2	-	0.79	0.010	27(a)	-	9(a)	27	>110	>71.5(a)
Outlet Nozzle	A508 Cl. 2	-	0.72	0.010	7(a)	-	-22(a)	7	>111	>72(a)
Outlet Nozzle	A508 Cl. 2	-	0.72	0.010	42(a)	-	23(a)	42	>140	>91(a)
Upper Shell	A508 Cl. 2	-	0.68	0.010	50	-	44(a)	50	>129	>83.5(a)
Inter. Shell	A508 Cl. 2	0.058	0.70	0.010	40	-	25(a)	40	>122	>79(a)
Lower Shell	A508 Cl. 2	0.079	0.67	0.010	30	-	2(a)	30	163	106(a)
Trans. Ring	A508 Cl. 2	-	0.69	0.013	60(a)	-	58(a)	60	>109	>70.5(a)
Bot. Hd. Dome	A302 Gr. B	-	-	0.010	-10	-	NA	30	NA	NA
Inter. to Lower Shell Girth Weld	SAW	0.26	0.60	0.011	10(b)	-	63	10(b)	-	63
HAZ	HAZ	-	-	-	0(a)	-	0	0	-	168

(a) Estimated values based on NUREG-0800, Branch Technical Position - MTEB 52
(b) Actual Value

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TECHNICAL SPECIFICATION BASES

TABLE B 3/4.4-2

REACTOR VESSEL TOUGHNESS (UNIT 4)

Component	Material Type	Cu (%)	Ni (%)	P (%)	NDTT (°F)	50 ft lb/35 mils Lateral Expansion Temp (°F) Long	Trans	RT_{NDT} (°F)	Minimum Upper Shelf (ft lb) Long	Trans
Cl. Hd. Dome	A302 Gr. B	-	-	0.008	-20	-	NA	30	NA	NA
Cl. Hd. Flange	A508 Cl. 2	-	0.72	0.010	-4(a)	-	27(a)	-4	199	129(a)
Ves. Sh. Flange	A508 Cl. 2	-	0.68	0.010	-1(a)	-	-11(a)	-1	176	114(a)
Inlet Nozzle	A508 Cl. 2	0.08	0.71	0.009	60(a)	-	NA	60	NA	NA
Inlet Nozzle	A508 Cl. 2	-	0.84	0.019	60(a)	-	NA	60	NA	NA
Inlet Nozzle	A508 Cl. 2	-	0.75	0.008	16(a)	-	13(a)	16	162	105(a)
Outlet Nozzle	A508 Cl. 2	-	0.78	0.010	7(a)	-	-25(a)	7	165	107(a)
Outlet Nozzle	A508 Cl. 2	-	0.68	0.010	38(a)	-	16(a)	38	160	104(a)
Outlet Nozzle	A508 Cl. 2	-	0.70	0.010	60(a)	-	42(a)	60	143	93(a)
Upper Shell	A508 Cl. 2	-	0.70	0.010	40	-	32(a)	40	156	101(a)
Inter. Shell	A508 Cl. 2	0.054	0.69	0.010	50	-	90(a)	50	143	93(a)
Lower Shell	A508 Cl. 2	0.056	0.74	0.010	40	-	38(a)	40	149	97(a)
Trans. Ring	A508 Cl. 2	-	0.69	0.011	60(a)	-	30(a)	60	NA	NA
Bot. Hd. Dome	A302 Gr. B	-	-	0.010	10	-	30(a)	10	NA	NA
Inter. to Lower Shell Girth Weld	SAW	0.26	0.60	0.011	10(b)	-	63	10(b)	NA	63
HAZ	HAZ	-	-	-	0	-	NA	0	NA	140

(a) Estimated values based on NUREG-0800, Branch Technical Position - MTEB 52
(b) Actual Value

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.9 PRESSURE/TEMPERATURE LIMITS (Continued)

Allowable pressure-temperature relationships for various heatup and cooldown rates are calculated using methods derived from Appendix G in Section III of the ASME Boiler and Pressure Vessel Code as required by Appendix G to 10 CFR Part 50 and Westinghouse Report GTSD-A-1.12, "Procedure for Developing Heatup and Cooldown Curves."

The general method for calculating heatup and cooldown limit curves is based upon the principles of the linear elastic fracture mechanics (LEFM) technology. In the calculation procedures a semi-elliptical surface defect with a depth of one-quarter of the wall thickness, T, and a length of 3/2T is assumed to exist at the inside of the vessel wall as well as at the outside of the vessel wall. The dimensions of this postulated crack, referred to in Appendix G of ASME Section III as the reference flaw, amply exceed the current capabilities of inservice inspection techniques. Therefore, the reactor operation limit curves developed for this reference crack are conservative and provide sufficient safety margins for protection against nonductile failure. To assure that the radiation embrittlement effects are accounted for in the calculation of the limit curves, the most limiting value of the nil-ductility reference temperature, RT_{NDT}, is used and this includes the radiation-induced shift, ΔRT_{NDT}, corresponding to the end of the period for which heatup and cooldown curves are generated.

The ASME approach for calculating the allowable limit curves for various heatup and cooldown rates specifies that the total stress intensity factor, K_I, for the combined thermal and pressure stresses at any time during heatup or cooldown cannot be greater than the reference stress intensity factor, K_{IR}, for the metal temperature at that time. K_{IR} is obtained from the reference fracture toughness curve, defined in Appendix G to the ASME Code. The K_{IR} curve is given by the equation:

$$K_{IR} = 26.78 + 1.223 \exp [0.0145(T-RT_{NDT} + 160)] \qquad (1)$$

Where: K_{IR} is the reference stress intensity factor as a function of the metal temperature T and the metal nil-ductility reference temperature RT_{NDT}. Thus, the governing equation for the heatup-cooldown analysis is defined in Appendix G of the ASME Code as follows:

$$C\, K_{IM} + K_{IT} \leq K_{IR} \qquad (2)$$

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.9 PRESSURE/TEMPERATURE LIMITS (Continued)

Where: K_{IM} = the stress intensity factor caused by membrane (pressure) stress,

K_{IT} = the stress intensity factor caused by the thermal gradients,

K_{IR} = constant provided by the Code as a function of temperature relative to the RT_{NDT} of the material,

C = 2.0 for level A and B service limits, and

C = 1.5 for inservice hydrostatic and leak test operations.

At any time during the heatup or cooldown transient, K_{IR} is determined by the metal temperature at the tip of the postulated flaw, the appropriate value for RT_{NDT}, and the reference fracture toughness curve. The thermal stresses resulting from temperature gradients through the vessel wall are calculated and then the corresponding thermal stress intensity factor, K_{IT}, for the reference flaw is computed. From Equation (2) the pressure stress intensity factors are obtained and, from these, the allowable pressures are calculated.

COOLDOWN

For the calculation of the allowable pressure versus coolant temperature during cooldown, the Code reference flaw is assumed to exist at the inside of the vessel wall. During cooldown, the controlling location of the flaw is always at the inside of the wall because the thermal gradients produce tensile stresses at the inside, which increase with increasing cooldown rates. Allowable pressure-temperature relations are generated for both steady-state and finite cooldown rate situations. From these relations, composite limit curves are constructed for each cooldown rate of interest.

The use of the composite curve in the cooldown analysis is necessary because control of the cooldown procedure is based on measurement of reactor coolant temperature, whereas the limiting pressure is actually dependent on the material temperature at the tip of the assumed flaw. During cooldown, the 1/4T vessel location is at a higher temperature than the fluid adjacent to the vessel ID. This condition, of course, is not true for the steady-state situation. It follows that at any given reactor coolant temperature, the ΔT developed during cooldown results in a higher value of K_{IR} at the 1/4T location for finite cooldown rates than for steady-state operation. Furthermore, if conditions exist such that the increase in K_{IR} exceeds K_{IT}, the calculated allowable pressure during cooldown will be greater than the steady-state value.

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.9 PRESSURE/TEMPERATURE LIMITS (Continued)

The above procedures are needed because there is no direct control on temperature at the 1/4T location; therefore, allowable pressures may unknowingly be violated if the rate of cooling is decreased at various intervals along a cooldown ramp. The use of the composite curve eliminates this problem and assures conservative operation of the system for the entire cooldown period.

HEATUP

Three separate calculations are required to determine the limit curves for finite heatup rates. As is done in the cooldown analysis, allowable pressure-temperature relationships are developed for steady-state conditions as well as finite heatup rate conditions assuming the presence of a 1/4T defect at the inside of the vessel wall. The thermal gradients during heatup produce compressive stresses at the inside of the wall that alleviate the tensile stresses produced by internal pressure. The metal temperature at the crack tip lags the coolant temperature; therefore, the K_{IR} for the 1/4T crack during heatup is lower than the K_{IR} for the 1/4T crack during steady-state conditions at the same coolant temperature. During heatup, especially at the end of the transient, conditions may exist such that the effects of compressive thermal stresses and different K_{IR}'s for steady-state and finite heatup rates do not offset each other and the pressure-temperature curve based on steady-state conditions no longer represents a lower bound of all similar curves for finite heatup rates when the 1/4T flaw is considered. Therefore, both cases have to be analyzed in order to assure that at any coolant temperature the lower value of the allowable pressure calculated for steady-state and finite heatup rates is obtained.

The second portion of the heatup analysis concerns the calculation of pressure-temperature limitations for the case in which a 1/4T deep outside surface flaw is assumed. Unlike the situation at the vessel inside surface, the thermal gradients established at the outside surface during heatup produce stresses which are tensile in nature and thus tend to reinforce any pressure stresses present. These thermal stresses, of course, are dependent on both the rate of heatup and the time (or coolant temperature) along the heatup ramp. Furthermore, since the thermal stresses at the outside are tensile and increase with increasing heatup rate, a lower bound curve cannot be defined. Rather, each heatup rate of interest must be analyzed on an individual basis.

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TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

HEATUP (Continued)

Following the generation of pressure-temperature curves for both the steady-state and finite heatup rate situations, the final limit curves are produced as follows. A composite curve is constructed based on a point-by-point comparison of the steady-state and finite heatup rate data. At any given temperature, the allowable pressure is taken to be the lesser of the three values taken from the curves under consideration.

The use of the composite curve is necessary to set conservative heatup limitations because it is possible for conditions to exist such that over the course of the heatup ramp the controlling condition switches from the inside to the outside and the pressure limit must at all times be based on analysis of the most critical criterion.

Finally, the 10 CFR 50 Appendix G rule which addresses the metal temperature of the closure head flange and vessel flange regions is considered. The rule states that the minimum metal temperature for the flange regions should be at least 120°F higher than the limiting RT_{NDT} for these regions when the pressure exceeds 20 percent of the pre-service hydrostatic test pressure (621 psig). Since the limiting RT_{NDT} for the flange regions for Turkey Point Units 3 and 4 is 44°F, the minimum temperature required for pressure of 621 psig and greater based on the Appendix G rule is 164°F. The heatup and cooldown curves as shown in Figures 3.4-2 to 3.4-4 clearly satisfy the above requirement by ample margins.

Finally, the composite curves for the heatup rate data and the cooldown rate data are adjusted for possible errors in the pressure and temperature sensing instruments by the values indicated on the respective curves.

The limitations imposed on the pressurizer heatup and cooldown rates and spray water temperature differential are provided to assure that the pressurizer is operated within the design criteria assumed for the fatigue analysis performed in accordance with the ASME Code requirements.

OVERPRESSURE MITIGATING SYSTEM

The Technical Specifications provide requirements to isolate High Pressure Safety Injection from the RCS and to prevent the start of an idle RCP if secondary temperature is more than 50°F above the RCS cold leg temperatures. These requirements are designed to ensure that mass and heat input transients more severe than those assumed in the low temperature overpressurization protection analysis cannot occur.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

OVERPRESSURE MITIGATING SYSTEM (Continued)

The OPERABILITY of two PORVs or an RCS vent opening of at least 2.20 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to 275°F. Either PORV has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either: (1) the start of an idle RCP with the secondary water temperature of the steam generator less than or equal to 50°F above the RCS cold leg temperatures including margin for instrument error, or (2) the start of a HPSI pump and its injection into a water-solid RCS. When the PORVs or 2.2 square inch area vent is used to mitigate a plant transient, a Special Report is submitted. However, minor increases in pressure resulting from planned plant actions, which are relieved by designated openings in the system, need not be reported.

Associated requirements for accomplishing specific tests and verifications in SR 4.4.9.3.1.a and 4.4.9.3.1.d allow a 12 hour delay after decreasing RCS cold leg temperature to ≤ 275°F. The bases for the 12 hour relief in completing the analog channel operation test (ACOT) and verifying the OPERABILITY of the backup Nitrogen supply are provided in the proposed license amendment correspondence L-2000-146 and in the NRC Safety Evaluation Report provided in the associated Technical Specification Amendments 208/202 effective October 30, 2000.

Based on the justifications provided therein and the discussion provided in NUREG-1431, Volume 1, Rev.2 (Westinghouse Standard Technical Specifications. Section B3.4.12), the 12 hour delay allowed for completing SR 4.4.9.3.1.a and 4.4.9.3.1.d is considered to start coincident with the enabling of OMS, regardless of RCS cold leg temperature. For example, if OMS is enabled at RCS cold leg temperature of 298°F, the ACOT must be completed within 12 hours of placing OMS in service (not 12 hours after decreasing RCS cold leg temperature to ≤ 275°F). (Reference: PTN-ENG-SENS-03-0046 approved 9/12/03.)

REACTOR MATERIAL SURVEILLANCE PROGRAM

Each Type I capsule contains 28 V-notch specimens, ten Charpy specimens machined from each of the two shell forgings. The remaining eight Charpy specimens are machined from correlated monitor material. In addition, each Type I capsule contains four tensile specimens (two specimens from each of the two shell forgings) and six WOL specimens (three specimens from each of the two shell forgings). Dosimeters of copper, nickel, aluminum-cobalt, and cadmium-shielded aluminum-cobalt wire are secured in holes drilled in spacers at the top, middle and bottom of each Type I capsule.

Each Type II capsule contains 32 Charpy V-notch specimens: eight specimens machined from one of the shell forgings, eight specimens of weld metal and eight specimens of HAZ metal, the remaining eight specimens are correlation monitors. In addition, each Type II capsule contains four tensile specimens and four WOL specimens: two tensile specimens and two WOL specimens from one of the shell forgings and the weld metal. Each Type II capsule contains a dosimeter block at the center of the capsule. Two cadmium-oxide-shielded capsules, containing the two isotopes uranium-238 and neptunium-237, are contained in the dosimeter block. The double containment afforded by the dosimeter assembly prevents loss and contamination by the neptunium-237 and uranium-238 and their activation products.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

REACTOR MATERIAL SURVEILLANCE PROGRAM (Continued)

Each dosimeter block contains approximately 20 milligrams of neptunium-237 and 13 milligrams of uranium-238 contained in a 3/8-inch OD sealed brass tube. Each tube is placed in a 1/2-inch diameter hole in the dosimeter block (one neptunium-237 and one uranium-238 tube per block), and the space around the tube is filled with cadmium oxide. After placement of this material, each hole is blocked with two 1/16-inch aluminum spacer discs and an outer 1/8-inch steel cover disc, which is welded in place. Dosimeters of copper, nickel, aluminum-cobalt and cadmium-shielded aluminum-cobalt are also secured in holes drilled in spacers located at the top, middle and bottom of each Type II capsule.

Capsule Type	Capsule Identification
I	S
II	V
II	T
I	U
II	X
I	W
I	Y
I	Z

This program combines the Reactor Surveillance Program into a single integrated program which conforms to the requirements of 10 CFR 50 Appendices G and H.

3/4.4.10 STRUCTURAL INTEGRITY

The inservice inspection and testing programs for ASME Code Class 1, 2, and 3 components ensure that the structural integrity and operational readiness of these components will be maintained at an acceptable level throughout the life of the plant. These programs are in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50.55a(g) except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i).

Components of the Reactor Coolant System were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1970 Edition and Addenda through winter 1970.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.4 REACTOR COOLANT SYSTEM (Continued)

3/4.4.11 REACTOR COOLANT SYSTEM VENTS

Reactor Coolant System vents are provided to exhaust noncondensible gases and/or steam from the Reactor Coolant System that could inhibit natural circulation core cooling. The OPERABILITY of at least one Reactor Coolant System vent path from the reactor vessel head and the pressurizer steam space ensures that the capability exists to perform this function.

The valve redundancy of the Reactor Coolant System vent paths serves to minimize the probability of inadvertent or irreversible actuation while ensuring that a single failure of a vent valve, power supply, or control system does not prevent isolation of the vent path.

Due to Appendix R considerations, the fuses for the reactor vessel head vent system solenoid valves are removed to prevent inadvertent opening of a leak path form the primary system during a fire (Ref: JPN-PTN-SEEJ-89-0076, Rev 1). The reactor vessel head vent system solenoid valves are considered operable with the fuses pulled since the removal and the administrative control of these fuses is controlled by plant procedures. The performances of the specified surveillances will verify the operability of the system.

The function, capabilities, and testing requirements of the Reactor Coolant System vents are consistent with the requirements of Item II.B.1 of NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

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TECHNICAL SPECIFICATION BASES

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ACCUMULATORS

The OPERABILITY of each Reactor Coolant System (RCS) accumulator ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs in the event the RCS pressure falls below the pressure of the accumulators. This initial surge of water into the core provides the initial cooling mechanism during large RCS pipe ruptures.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 1000 psig, and the limits established in the surveillance requirements for contained volume, boron concentration, and nitrogen cover pressure must be met. Operability of the accumulators does not depend on the operability of the water level and pressure channel instruments, therefore, accumulator volume and nitrogen cover pressure surveillance may be verified by any valid means, not just by instrumentation.

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break Loss of Coolant Accident (LOCA) is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. In addition, current Turkey Point analysis demonstrates that the accumulators discharge only a small amount following a large main steam line break. Their impact is minor since the use of the accumulator volume compensates for Reactor Coolant System shrinkage and the change in boron concentration is insignificant. Thus, 72 hours is allowed to return the boron concentration to within limits.

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 1 hour. In this condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 1 hour completion time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The completion time minimizes the potential for exposure of the plant to a LOCA under these conditions.

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TECHNICAL SPECIFICATION BASES

3/4.5 EMERGENCY CORE COOLING SYSTEMS (Continued)

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS

The OPERABILITY of ECCS components and flowpaths required in Modes 1, 2 and 3 ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming any single active failure consideration. Two SI pumps and one RHR pump operating in conjunction with two accumulators are capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all pipe break sizes up to and including the maximum hypothetical accident of a circumferential rupture of a reactor coolant loop. In addition, the RHR subsystem provides long–term core cooling capability in the recirculation mode during the accident recovery period.

Motor Operated Valves (MOVs) 862A, 862B, 863A, 863B are required to take suction from the containment sump via the RHR system. PC-600 supplies controlling signals to valves MOVs 862B and 863B, to prevent opening these valves if RHR pump B discharge pressure is above 210 psig. PC-601 provides similar functions to valves MOVs 862A and 863A. Although all four valves are normally locked in position, with power removed, the capability to power up and stroke the valves must be maintained in order to satisfy the requirements for OPERABLE flow paths (capable of taking suction from the containment sump).

When PC-600/-601 are calibrated, a test signal is supplied to each circuit to check operation of the relays and annunciators operated by subject controllers. This test signal will prevent MOVs 862A, 862B, 863A, 863B from opening. Therefore it is appropriate to tag out the MOV breakers, and enter Technical Specification Action Statement 3.5.2.a. and 3.6.2.1 when calibrating PC-600/-601.

With the RCS temperature below 350°F, operation with less than full redundant equipment is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the limited core cooling requirements.

TS 3.5.2, Action g. provides an allowed outage/action completion time (AOT) of up to 7 days to restore an inoperable RHR pump to OPERABLE status, provided the affected ECCS subsystem is inoperable only because its associated RHR pump is inoperable. This 7 day AOT is based on the results of a deterministic and probabilistic safety assessment, and is referred to as a 'risk-informed" AOT extension. Planned entry into this AOT requires that a risk assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the administrative procedure that implements the maintenance rule pursuant to 10CFR50.56.

TECHNICAL SPECIFICATION BASES

3/4.5 EMERGENCY CORE COOLING SYSTEMS (Continued)

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS (Continued)

TS Surveillance 4.5.2.a requires that each ECCS component and flow path be demonstrated operable at least once per 12 hours by verifying by control room indication that the valves listed in section 4.5.2.a are in the indicated positions with power to the valve operators removed. "Verifying control room indication" applies to the valve position and not to the valve operator power removal. The breaker position may be verified by either the off condition of the breaker position indication light in the Control Room, or the verification of the locked open breaker position in the field. Verifying that power is removed to the applicable valve operators can be accomplished by direct field indication of the breaker (locked in the open position), or by observation of the breaker position status lamp in the control room (lamp is off when breaker is open). Surveillance Requirements for throttle valve position stops prevent total pump flow from exceeding runout conditions when the system is in its minimum resistance configuration.

Pump performance requirements are obtained from accident analysis assumptions. Varying flowrates are provided to accommodate testing during modes and alignments.

In the RHR test, differential head is specified in "feet." This criteria will allow for compensation of test data with water density due to varying temperature.

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.4 REFUELING WATER STORAGE TANK

The OPERABILITY of the refueling water storage tank (RWST) as part of the ECCS ensures that a sufficient supply of borated water is available for injection by the ECCS in the event of a LOCA. The limits on RWST minimum volume and boron concentration ensure that: (1) sufficient water is available within containment to permit recirculation cooling flow to the core, and (2) the reactor will remain subcritical in the cold condition following mixing of the RWST and the RCS water volumes with all control rods assumed out of the core to maximize boron requirements.

The assumptions made in the LOCA analyses credit control rods for the SBLOCA and cold leg large break LOCA and do not credit control rods for the hot leg large break LOCA. For the cold leg large break LOCA, control rods are assumed inserted only at the time of hot leg switchover to provide the additional negative reactivity required to address concerns of potential core recriticality at the time. (Reference: PTN-ENG-SEFJ-02-016 approved 11/14/03, PNSC #03-167.)

The indicated water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

The temperature limits on the RWST solution ensure that: 1) the solubility of the borated water will be maintained, and 2) the temperature of the RWST solution is consistent with the LOCA analysis. Portable instrumentation may be used to monitor the RWST temperature.

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TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 CONTAINMENT INTEGRITY

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the SITE BOUNDARY radiation doses to within the dose guideline values of 10 CFR Part 100 during accident conditions.

Note that some penetrations don't fall under Technical Specification 3.6.1.1. For example Penetration 38 is an electrical penetration only, closed by virtue of its seal(s), and therefore nothing needs to happen to close the penetration during accident conditions; it is considered already closed. A passive failure would be required in order to get communication between the containment atmosphere and the outside atmosphere through this penetration (Turkey Point's license does not require consideration of passive failures). Similarly, closed systems inside containment already satisfy the requirement for CONTAINMENT INTEGRITY, so Tech Spec 3.6.1.1 does not apply to them at all (unless the piping itself is breached, which would be a passive failure).

With these distinctions, Surveillance Requirement 4.6.1.1 is explained as follows: (1) as long as a penetration is capable of being closed by an OPERABLE containment automatic isolation valve, 4.6.1.1 is met and (2) if the penetration is not required to be closed during accident conditions, 4.6.1.1 is met. For example, penetrations 58 and 59 are for High Head Safety Injection, and therefore required to be open during accident conditions. Penetrations which don't meet one of the two criteria listed above (automatic valve, or not requiring closure), require verification that they are already closed by some other means (valve, blind flange, or deactivated automatic valve). Note that a deactivated automatic valve must be administratively controlled (tagged) in the closed position to take credit for it as a deactivated valve.

3/4.6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the safety analyses at the peak accident pressure, P_a. The measured as–found overall integrated leakage rate is limited to less than or equal to 1.0 L_a during the performance of the periodic test. As an added conservatism, the measured overall as-left integrated leakage rate is further limited to less than or equal to 0.75 L_a to account for possible degradation of the containment leakage barriers between leakage tests.

The surveillance testing for measuring leakage rates is in compliance with the requirements of Appendix J of 10 CFR Part 50, Option B [as modified by approved exemptions], and consistent with the guidance of Regulatory Guide 1.163, dated September 1995.

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TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS (Continued)

3/4.6.1.3 CONTAINMENT AIR LOCKS

The limitations on closure and leak rate for the containment air locks are required to meet the restrictions on CONTAINMENT INTEGRITY and containment leak rate. An interlock is provided on the Airlock to assure that both doors cannot be opened simultaneously, with the consequent loss of containment integrity with the interlock inoperable, Action Statement (AS) (a.) applies. With an interlock inoperable such that the closure of only one door can be assured, containment integrity can be maintained by complying with AS (a.1) without reliance on the status of the second door. Surveillance testing of the air lock seals provides assurance that the overall air lock leakage will not become excessive due to seal damage during the intervals between air lock leakage tests. Surveillance 4.6.1.3 assures the operability of an air lock by verifying the operability of door seals in Surveillance Requirement (SR) (a.), other potential leak paths in SR (b.), and the interlock in SR (c.). If SR (a.) or (c.) are not met, then a door is to be considered inoperable. (If both doors are incapable of being closed, the air lock is inoperable). If SR (b.) is not met, and the source of the leak is not identified or is confirmed to not be through a door, then the air lock is to be considered inoperable. In order to meet the ACTION requirement to lock the OPERABLE air lock door closed, the air lock door interlock may provide the required locking. In addition, the outer air lock door is secured under administrative controls. As long as the interlock physically prevents the door from being opened, the interlock is OPERABLE, and therefore the airlock is OPERABLE. However, should the air lock door begin to un-seal while performing the interlock test (such that the door leakage may be in question), the door would be considered inoperable (and the associated actions for one inoperable door taken). A containment air lock door would be considered "open" whenever the latch handle is out of the "Latched" position such that the door is free to open with a slight force, i.e., the door is closed but unlatched. The door should be considered "closed" whenever the latch mechanism physically prevents the door from being opened. With a containment air lock interlock mechanism inoperable, consider one containment airlock door out of service and maintain the other door closed and locked. During the air lock interlock test (SR (c.)), when an attempt is made to move the door handle in the "unlatched" direction, some movement in the handle may occur until the mechanical interlock makes hard contact. At this point the door is still physically restrained from opening, but the seating pressure against the o-ring seal may have been reduced such that the door seal is in an untested configuration, potentially creating a leakage path. In this configuration, the door is considered "closed" per the Technical Specifications and would satisfy the interlock test requirements, but the overall air lock leakage requirement may have been invalidated. This configuration would result in an inoperable airlock door since the O-ring seal was not properly compressed. As there is no functional difference between an unsecured door and a leaking door (as far as maintenance of containment integrity is concerned), the unsecured door must be considered inoperable.

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TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS (Continued)

3/4.6.1.4 INTERNAL PRESSURE

The limitations on containment internal pressure ensure that: (1) the containment structure is prevented from exceeding its design negative pressure differential of 2.5 psig with respect to the outside atmosphere, and (2) the containment peak pressure does not exceed the design pressure of 55 psig during LOCA conditions.

The maximum peak pressure expected to be obtained from a LOCA event is 49.9 psig assuming an initial containment pressure of 0.3 psig. An initial positive pressure of as much as 5 psi would result in a maximum containment pressure that is less than design pressure and is consistent with the safety analyses.

3/4.6.1.5 AIR TEMPERATURE

The limitations on containment average air temperature ensure that the design limits for a LOCA are not exceeded, and that the environmental qualification of equipment is not impacted. If temperatures exceed 120°F, but remain below 125°F for up to 336 hours during a calendar year, no action is required. If the 336-hour limit is approached, an evaluation may be performed to extend the limit if some of the hours have been spent at less than 125°F. Measurements shall be made at all listed locations, whether by fixed or portable instruments, prior to determining the average air temperature.

3/4.6.1.6 CONTAINMENT STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the facility. Structural integrity is required to ensure that the containment will withstand the maximum analyzed peak pressure of 49.9 psig in the event of a LOCA. The measurement of containment tendon lift-off force, the tensile tests of the tendon wires or strands, the visual examination of tendons, anchorages and exposed interior and exterior surfaces of the containment, and the Type A leakage test are sufficient to demonstrate this capability.

TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS (Continued)

3/4.6.1.6 CONTAINMENT STRUCTURAL INTEGRITY (Continued)

Some containment tendons are inaccessible at one end due to personnel safety considerations at potential steam exhaust locations. These tendons, if selected for examination, will be exempted from the full examination requirements, and the following alternative examinations shall be performed:

1. The accessible end of each exempt tendon shall be examined in accordance with IWL-2524 and IWL-2525.
2. For each exempt tendon, a substitute tendon shall be selected and examined in accordance with IWL requirements.
3. In addition, an accessible tendon located as close as possible to each exempt tendon shall be examined at both ends in accordance with IWL-2524 and IWL-2525.

The required Special Reports from any engineering evaluation of containment abnormalities shall include a description of the tendon condition, the condition of the concrete (specially at tendon anchorages), the inspection procedures, the tolerances on cracking, the results of the engineering evaluation, and the corrective actions taken.

The submittal of a Special Report for a failed tendon surveillance is considered an administrative requirement and it does not impact the plant operability. The administrative requirements for Special Reports are defined in Technical Specifications section 6.9.2.

3/4.6.1.7 CONTAINMENT VENTILATION SYSTEM

The containment purge supply and exhaust isolation valves are required to be closed during a LOCA. When not purging, power to the purge valve actuators will be removed (sealed closed) to prevent inadvertent opening of these values. Maintaining these valves sealed closed during plant operation ensures that excessive quantities of radioactive materials will not be released via the Containment Purge System.

Leakage integrity tests with a maximum allowable leakage rate for containment purge supply and exhaust supply valves will provide early indication of resilient material seal degradation and will allow opportunity for repair before gross leakage failures could develop. The 0.60 L_a leakage limit shall not be exceeded when the leakage rates determined by the leakage integrity tests of these valves are added to the previously determined total for all valves and penetrations subject to Type B and C tests.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS (Continued)

3/4.6.2 DEPRESSURIZATION AND COOLING SYSTEMS

3/4.6.2.1 CONTAINMENT SPRAY SYSTEM

The OPERABILITY of the Containment Spray System ensures that containment depressurization capability will be available in the event of a LOCA. The pressure reduction and resultant lower containment leakage rate are consistent with the assumptions used in the safety analyses.

The allowable out-of-service time requirements for the Containment Spray System have been maintained consistent with that assigned other inoperable ESF equipment and do not reflect the additional redundancy in cooling capability provided by the Emergency Containment Cooling System. Pump performance requirements are obtained from the accidents analysis assumptions.

Motor Operated Valves (MOVs) 862A, 862B, 863A, 863B are required to take suction from the containment sump via the RHR system. PC-600 supplies controlling signals to valves MOVs 862B and 863B, to prevent opening these valves if RHR pump B discharge pressure is above 210 psig. PC-601 provides similar functions to valves MOVs 862A and 863A. Although all four valves are normally locked in position, with power removed, the capability to power up and stroke the valves must be maintained in order to satisfy the requirements for OPERABLE flow paths (capable of taking suction from the containment sump).

When PC-600/-601 are calibrated, a test signal is supplied to each circuit to check operation of the relays and annunciators operated by subject controllers. This test signal will prevent MOVs 862A, 862B, 863A, 863B from opening. Therefore it is appropriate to tag out the MOV breakers, and enter Technical Specification Action Statement 3.5.2.a. and 3.6.2.1 when calibrating PC-600/-601.

3/4.6.2.2 EMERGENCY CONTAINMENT COOLING SYSTEM

The OPERABILITY of the Emergency Containment Cooling (ECC) System ensures that the heat removal capacity is maintained with acceptable ranges following postulated design basis accidents. To support both containment integrity safety analyses and component cooling water thermal analysis, a maximum of two ECCs can receive an automatic start signal following generation of a safety injection (SI) signal (one ECC receives an "A" train SI signal and another ECC receives a "B" train SI signal). To support post-LOCA long-term containment pressure/temperature analyses, a maximum of two ECCs are required to operate. The third (swing) ECC is required to be OPERABLE to support manual starting following a postulated LOCA event for containment pressure/temperature suppression.

TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS (Continued)

3/4.6.2.2 EMERGENCY CONTAINMENT COOLING SYSTEM (Continued)

The allowable out-of-service time requirements for the Containment Cooling System have been maintained consistent with that assigned other inoperable ESF equipment and do not reflect the additional redundancy in cooling capability provided by the Containment Spray System.

The surveillance requirement for ECC flow is verified by correlating the test configuration value with the design basis assumptions for system configuration and flow. An 18-month surveillance interval is acceptable based on the use of water from the CCW system, which results in a low risk of heat exchanger tube fouling.

3/4.6.3 EMERGENCY CONTAINMENT FILTERING SYSTEM

The OPERABILITY of the Emergency Containment Filtering System ensures that sufficient iodine removal capability will be available in the event of a LOCA. The reduction in containment iodine inventory reduces the resulting SITE BOUNDARY radiation doses associated with containment leakage. System components are not subject to rapid deterioration. Visual inspection and operating/performance tests after maintenance, prolonged operation, and at the required frequencies provide assurances of system reliability and will prevent system failure. In-situ filter performance tests are conducted in accordance with the methodology and intent of ANSI N510- 1975. Charcoal samples are tested using ASTM D3803-1989 in accordance with Generic Letter 99-02. The test conditions (30°C and 95% relative humidity) are as specified in the Generic Letter. Table 1 of the ASTM standard provides the tolerances that must be met during the test for each test parameter. The specified methyl iodide penetration value is based on the assumptions used in the LOCA analysis with a safety factor of 2. Technical Specification 3.6.3 requires three ECFs to be OPERABLE in Modes 1, 2, 3, and 4. Surveillance Requirement 4.6.3.d.2) states that each ECF be demonstrated OPERABLE... at least once per 18 months... by verifying that the filter cooling solenoids can be opened by operator action and are opened automatically on a loss of flow signal.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS (Continued)

3/4.6.3 EMERGENCY CONTAINMENT FILTERING SYSTEM (Continued)

The Technical Specification does not require that both independent trains of ECF dousing components be OPERABLE to support the ECFs.

1. Disabling one train of ECF dousing components does not render the associated ECF inoperable.
2. Removing power ONLY from a flow switch renders the ECF inoperable.
3. Removing power from a dousing valve DOES NOT render the ECF inoperable.
4. To de-energize a flow switch without impacting the operability of the ECF, de-energize the associated dousing valve first.

The UFSAR states that the design requirement for the ECF system is to reduce the iodine concentration in the containment atmosphere following a MHA, to levels ensuring that the off-site dose will not exceed the guidelines of 10 CFR 100 at the site boundary. Details of the site boundary dose calculations are given in Section 14.3.5 of the UFSAR.

Following a loss of coolant accident, a safety injection signal will automatically energize motor control circuits to start the three filter unit fans. If outside power or full emergency power is available, all three-filter units are started (only two are required). If electric power is limited due to the failure of an emergency diesel generator, two of the three units are started.

A borated water spray system is installed in each filter unit to dissipate the radioactive decay heat and initiated by the loss of air flow through the filter unit, such as failure of the fan. The Design Basis Document for the ECF system states that radioactive decay heat removal by dousing the ECF charcoal bed with containment spray water on ECF fan failure is a Quality Related function. As such, single failure criteria do not apply to the ECF spray system components because:

1) Dousing is not required for the ECF to perform its safety-related function of removing radioactive iodine and methyl iodide from the containment atmosphere,

2) Dousing is not required to maintain offsite doses below 10CFR100 limits, and

3) The ECF system can perform its safety-related functions with any single failure without requiring dousing.

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TECHNICAL SPECIFICATION BASES

3/4.6 CONTAINMENT SYSTEMS (Continued)

3/4.6.3 EMERGENCY CONTAINMENT FILTERING SYSTEM (Continued)

The borated water spray system provided with each charcoal filter plenum is designed to drench the absorbers thoroughly. Two independent trains of ECF dousing components are provided for reliability purposes. Borated water for this system is obtained from the main headers of the containment spray system through a separate 2-inch line to each filter plenum. Two normally closed power operated valves in parallel in the 2-inch line ensure that flow can be initiated when required. Airflow is sensed by two independent flow switches installed at the fan discharge. The associated power operated valve is energized and opened upon a loss of airflow as detected by its associated flow switch, which de-energizes to actuate. Each spray system can also be manually operated by the operator in the control room.

All three channel A ECF dousing flow switches are powered from a single vital AC supply power, and all three channel B flow switches are powered from a different vital AC supply power. Calibration of the flow switches requires that one train of flow switches for all three ECFs be de-energized. This would fail the power-operated valves in the open position because the flow switch design is to de-energize to actuate. However, the associated solenoid valves can be failed in the closed position by removing power to the valves. The fail-closed position of the power-operated valves precludes inadvertent dousing of the ECFs upon Safety Injection. The other independent train of ECF dousing components remain capable of performing its required Quality Related function.

Welding and painting inside containment is acceptable provided the compensatory actions described in safety evaluation JPN-PTN-SEMS-91-060 are satisfactorily performed. The above referenced evaluation demonstrates that the ECFs will not experience "operational exposure" of painting, fire, or chemical releases as described in TS 4.6.3 b. Therefore, the operability demonstration required by TS 4.6.3 b. is not required providing the compensatory actions described in safety evaluation JPN–PTN–SEMS-91-060 are satisfactorily performed.

3/4.6.4 CONTAINMENT ISOLATION VALVES

The OPERABILITY of the containment isolation valves ensures that the containment atmosphere will be isolated from the outside environment in the event of a release of radioactive material to the containment atmosphere or pressurization of the containment. Containment isolation within the time limits specified in the In-Service Testing Program is consistent with the assumed isolation times of those valves with specific isolation times in the LOCA analysis.

Note that Tech Spec 3.6.4 applies only to automatic containment isolation valves. Automatic containment isolation valves are valves, which close automatically on a Containment Isolation Phase A signal, Containment Phase B, or a Containment Ventilation Isolation signal, and check valves.

TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line Code safety valves ensures that the Secondary System pressure will be limited to within 110% (1193.5 psig) of its design pressure of 1085 psig during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a Turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section VIII of the ASME Boiler and Pressure Code, 1971 Edition. The total relieving capacity for all valves on all of the steam lines is 10,670,000 lbs/h which is 111% of the total secondary steam flow of 9,600,000 lbs/h at 100% RATED THERMAL POWER. A minimum of one OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for the allowable THERMAL POWER restriction in Table 3.7-1.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in Secondary Coolant System steam flow and THERMAL POWER required by the reduced Reactor trip settings of the Power Range Neutron Flux channels. The Reactor Trip Setpoint reductions are derived on the following bases:

$$Hi\Phi = (100/Q)\ \frac{(w_s\ h_{fg}\ N)}{K}$$

Where:

Hi Φ	=	Reduced THERMAL POWER for the most limiting steam generator expressed as a percent of RTP
Q	=	Nominal Nuclear Steam Supply System (NSSS) power rating of the plant (including reactor coolant pump heat), Mwt
K	=	Conversion factor; 947.82 (Btu/sec)/Mwt
w_s	=	Minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure (including tolerance and accumulation) - (Lbm/sec). For example, if the maximum number of inoperable MSSVs on any one steam generator is one, then w_s should be a summation of the capacity of the operable MSSVs at the highest operable MSSV operating pressure, excluding the highest capacity MSSV. If the maximum number of inoperable MSSVs per steam generator is three, then w_s should be a summation of the capacity of the operable MSSV at the highest operable MSSV operating pressure, excluding the three highest capacity MSSVs.

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TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.1.1 SAFETY VALVES (Continued)

h_{fg} = Heat of vaporization for steam at the highest MSSV opening pressure (including tolerance and accumulation) - (Btu/lbm)

N = Number of loops in plant

The values calculated from this algorithm must then be adjusted lower for use in TS 3.7.1.1 to account for instrument and channel uncertainties.

Operation with less than all four MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is proportionally limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator. Table 3.7-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the surveillance to allow for drift.

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the Auxiliary Feedwater System ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss-of-offsite power. Steam can be supplied to the pump turbines from either or both units through redundant steam headers. Two D.C. motor operated valves and one A.C. motor operated valve on each unit isolate the three main steam lines from these headers. Both the D.C. and A.C. motor operated valves are powered from safety-related sources. Auxiliary feedwater can be supplied through redundant lines to the safety-related portions of the main feedwater lines to each of the steam generators. Air operated fail closed flow control valves are provided to modulate the flow to each steam generator. Each steam driven auxiliary feedwater pump has sufficient capacity for single and two unit operation to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F when the Residual Heat Removal System may be placed into operation.

ACTION statement 2 describes the actions to be taken when both auxiliary feedwater trains are inoperable. The requirement to verify the availability of both standby feedwater pumps is to be accomplished by verifying that both pumps have successfully passed their monthly surveillance tests within the last surveillance interval. The requirement to complete this action before beginning a unit shutdown is to ensure that an alternate feedwater train is available before putting the affected unit through a transient. If no alternate feedwater trains are available, the affected unit is to stay at the same condition until an auxiliary feedwater train is returned to service, and then invoke ACTION statement 1 for the other train. If both standby feedwater pumps are made available before one auxiliary feedwater train is returned to an OPERABLE status, then the affected unit(s) shall be placed in at least HOT STANDBY within 6 hours and HOT SHUTDOWN within the following 6 hours.

TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM (Continued)

ACTION statement 3 describes the actions to be taken when a single auxiliary feedwater pump is inoperable. The requirement to verify that two independent auxiliary feedwater trains are OPERABLE is to be accomplished by verifying that the requirements for Table 3.7-3 have been successfully met for each train within the last surveillance interval. The provisions of Specification 3.0.4 are not applicable to the third auxiliary feedwater pump provided it has not been inoperable for longer than 30 days. This means that a unit(s) can change OPERATIONAL MODES during a unit(s) heatup with a single auxiliary feedwater pump inoperable as long as the requirements of ACTION statement 3 are satisfied.

The specified flow rate acceptance criteria conservatively bounds the limiting AFW flow rate modeled in the single unit loss of normal feedwater analysis. Dual unit events such as a two unit loss of offsite power require a higher pump flow rate, but it is not practical to test both units simultaneously. The monthly flow surveillance test specified in 4.7.1.2.1.1 is considered to be a general performance test for the AFW system and does not represent the limiting flow requirement for AFW. Check valves in the AFW system that require full stroke testing under limiting flow conditions are tested under Technical Specification 4.0.5.

The monthly testing of the auxiliary feedwater pumps will verify their operability. Proper functioning of the turbine admission valve and the operation of the pumps will demonstrate the integrity of the system. Verification of correct operation will be made both from instrumentation within the control room and direct visual observation of the pumps.

3/4.7.1.3 CONDENSATE STORAGE TANK

There are two (2) seismically designed 250,000 gallons condensate storage tanks. A minimum indicated volume of 210,000 gallons is maintained for each unit in MODES 1, 2 or 3. The OPERABILITY of the condensate storage tank with the minimum indicated volume ensures that sufficient water is available to maintain the Reactor Coolant System at HOT STANDBY conditions for approximately 23 hours or maintain the Reactor Coolant System at HOT STANDBY conditions for 15 hours and then cool down the Reactor Coolant System to below 350°F at which point the Residual Heat Removal System may be placed in operation.

The minimum indicated volume includes an allowance for instrument indication uncertainties and for water deemed unusable because of vortex formation and the configuration of the discharge line.

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TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.1.4 SPECIFIC ACTIVITY

The limit on secondary coolant specific activity is based on a postulated release of secondary coolant equivalent to the contents of three steam generators to the atmosphere due to a net load rejection. The limiting dose for this case would result from radioactive iodine in the secondary coolant. One tenth of the iodine in the secondary coolant is assumed to reach the site boundary making allowance for plate-out and retention in water droplets. The inhalation thyroid dose at the site boundary is then;

Dose (Rem) = C * V * B * DCF * X/Q * 0.1

Where: C = secondary coolant dose equivalent I-131 specific activity

= 0.2 curies/ m^3 (*µCi/cc) or 0.1 Ci/m^3 , each unit

V = equivalent secondary coolant volume released = 214 m^3

B = breathing rate = 3.47 x 10^{-4} m^3/sec.

X/Q = atmospheric dispersion parameter = 1.54 x 10^{-4} sec/m^3

0.1 = equivalent fraction of activity released

DCF = dose conversion factor, Rem/Ci

The resultant thyroid dose is less than 1.5 Rem.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blow down in the event of a steam line rupture. This restriction is required to: (1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the Surveillance Requirements are consistent with the assumptions used in the safety analyses. The 24–hour action time provides a reasonable amount of time to troubleshoot and repair the backup air and/or nitrogen system.

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TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES (Continued)

The Main Steam Bypass Valves (MSBV) as motor operated valves are required to provide the capability to warm the main steam lines and to equalize the steam pressure across the associated Main Steam Isolation Valve (MSIV). The MSBVs are provided with a motor operator to close on a main steam isolation signal if open. The MSIVs and their associated MSBVs are not Containment Isolation Valves. The MSBVs are not covered in any Technical Specifications and no LCO or Action Statements apply to them.

3/4.7.1.6 STANDBY STEAM GENERATOR FEEDWATER SYSTEM

The purpose of this specification and the supporting surveillance requirements is to assure operability of the non-safety grade Standby Steam Generator Feedwater System. The Standby Steam Generator Feedwater System consists of commercial grade components designed and constructed to industry and FPL standards of this class of equipment located in the outdoor plant environment typical of FPL facilities system wide. The system is expected to perform with high reliability, i.e., comparable to that typically achieved with this class of equipment. FPL intends to maintain the system in good operating condition with regard to appearance, structures, supports, component maintenance, calibrations, etc.

The function of the Standby Feedwater System for OPERABILITY determinations is that it can be used as a backup to the Auxiliary Feedwater (AFW) System in the event the AFW System does not function properly. The system would be manually started, aligned and controlled by the operator when needed.

The A pump is electric-driven and is powered from the non-safety related C bus. In the event of a coincident loss of offsite power, the B pump is diesel driven and can be started and operated independent of the availability of on-site or off-site power.

A supply of 65,000 gallons from the Demineralized Water Storage Tank for the Standby Steam Generator Feedwater Pumps is sufficient water to remove decay heat from the reactor for six (6) hours for a single unit or two (2) hours for two units. This was the basis used for requiring 65,000 gallons of water in the non-safety grade Demineralized Water Storage Tank and is judged to provide sufficient time for restoring the AFW System or establishing make-up to the Demineralized Water Storage Tank.

The minimum indicated volume (135,000 gallons) consists of an allowance for level indication instrument uncertainties (approximately 15,000 gallons); for water deemed unusable because of tank discharge line location and vortex formation (approximately 50,300 gallons); and the minimum usable volume (65,000 gallons). The minimum indicated volume corresponds to a water level of 8.5 feet in the Demineralized Water Storage Tank.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.1.6 STANDBY STEAM GENERATOR FEEDWATER SYSTEM (Continued)

The Standby Steam Generator Feedwater Pumps are not designed to NRC requirements applicable to Auxiliary Feedwater Systems and not required to satisfy design basis events requirements. These pumps may be out of service for up to 24 hours before initiating formal notification because of the extremely low probability of a demand for their operation.

The guidelines for NRC notification in case of both pumps being out of service for longer than 24 hours are provided in applicable plant procedures, as a voluntary 4-hour notification.

Adequate demineralized water for the Standby Steam Generator Feedwater system will be verified once per 24 hours. The Demineralized Water Storage Tank provides a source of water to several systems and therefore, requires daily verification.

The Standby Steam Generator Feedwater Pumps will be verified OPERABLE monthly on a STAGGERED TEST BASIS by starting and operating them in the recirculation mode. Also, during each unit's refueling outage, each Standby Steam Generator Feedwater Pump will be started and aligned to provide flow to the nuclear unit's steam generators.

This surveillance regimen will thus demonstrate operability of the entire flow path, backup non-safety grade power supply and pump associated with a unit at least each refueling outage. The pump, motor driver, and normal power supply availability would typically be demonstrated by operation of the pumps in the recirculation mode monthly on a staggered test basis.

The diesel engine driver for the B Standby Steam Generator Feedwater Pump will be verified operable once every 31 days on a staggered test basis performed on the B Standby Steam Generator Feedwater Pump. In addition, an inspection will be performed on the diesel at least once every 18 months in accordance with procedures prepared in conjunction with its manufacture's recommendations for the diesel's class of service. This inspection will ensure that the diesel driver is maintained in good operating condition consistent with FPL's overall objectives for system reliability.

3/4.7.2 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the Component Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single active failure, is consistent with the assumptions used in the safety analyses. One pump and two heat exchangers provide the heat removal capability for accidents that have been analyzed.

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TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.3 INTAKE COOLING WATER SYSTEM

The OPERABILITY of the Intake Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The design and operation of this system, assuming a single active failure, ensures cooling capacity consistent with the assumptions used in the safety analyses.

3/4.7.4 ULTIMATE HEAT SINK

The limit on ultimate heat sink (UHS) temperature in conjunction with the SURVEILLANCE REQUIREMENTS of Technical Specification 3/4.7.2 will ensure that sufficient cooling capacity is available either: (1) to provide normal cooldown of the facility, or (2) to mitigate the effects of accident conditions within acceptable limits.

FPL has the option of monitoring the UHS temperature by monitoring the temperature in the ICW system piping going to the inlet of the CCW heat exchangers. Monitoring the UHS temperature after the ICW but prior to CCW heat exchangers is considered to be equivalent to temperature monitoring before the ICW pumps. The supply water leaving the ICW pumps will be mixed and therefore, it will be representative of the bulk UHS temperature to the CCW heat exchanger inlet. The effects of the pump heating on the supply water are negligible due to low ICW head and high water volume. Accordingly, monitoring the UHS temperature after the ICW pumps but prior to the CCW heat exchangers provides an equivalent location for monitoring the UHS temperature.

With the implementation of the CCW heat exchanger performance monitoring program, the limiting UHS temperature can be treated as a variable with an absolute upper limit of 100°F without compromising any margin of safety. Demonstration of actual heat exchanger performance capability supports system operation with postulated canal temperatures greater than 100°F. Therefore, an upper Technical Specification limit of 100°F is conservative.

3/4.7.5 CONTROL ROOM EMERGENCY VENTILATION SYSTEM

The OPERABILITY of the Control Room Emergency Ventilation System ensures that: (1) the ambient air temperature does not exceed the allowable temperature for continuous-duty rating for the equipment and instrumentation cooled by this system, and (2) the control room will remain habitable for operations personnel during and following all credible accident conditions. The OPERABILITY of this system in conjunction with control room design provisions is based on limiting the radiation exposure to personnel occupying the control room to 5 rems or less whole body, or its equivalent. This limitation is consistent with the requirements of General Design Criterion 19 of Appendix A, 10 CFR Part 50.

TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.5 CONTROL ROOM EMERGENCY VENTILATION SYSTEM (Continued)

The Control Room Emergency Ventilation System is considered to be OPERABLE (Ref: JPN–PTN–SENP-92-017) when 1) three air handling units (AHUs) (one of each of the three air conditioning units) are operable, 2) two condensing units (two out of three available condensers) are operable, 3) one recirculation filter unit is operable, 4) two recirculation fans operable and 5) associated dampers are operable. The reason three AHUs are required is that in the event of a single failure, only two AHUs would be available to supply air to the suction of the recirculation filter and fan. This is the configuration tested to support Technical Specification operability for flow through the emergency charcoal filter. Taking one AHU out of service renders the system incapable of operating in accordance with the tested configuration assuming an accident and a single failure (i.e., only one air handling unit available instead of the two assumed by the analysis). Any one of the three condensing (air conditioning) units is capable of maintaining the control room equipment within its environmental limits for temperature and humidity. Thus, one condensing unit can be taken out of service without impacting the ability of the Control Room Emergency Ventilation System to accomplish its intended function under single failure conditions.

System components are not subject to rapid deterioration, having lifetimes of many years, even under continuous flow conditions. Visual inspection and operating tests provide assurance of system reliability and will ensure early detection of conditions which could cause the system to fail or operate improperly. The filters performance tests prove that filters have been properly installed, that no deterioration or damage has occurred, and that all components and subsystems operate properly. The in-situ tests are performed in accordance with the methodology and intent of ANSI N510 (1975) and provide assurance that filter performance has not deteriorated below returned specification values due to aging, contamination, or other effects. Charcoal samples are tested using ASTM D3803-1989 in accordance with Generic Letter 99-02. The test conditions (30°C and 95% relative humidity) are as specified in the Generic Letter. Table 1 of the ASTM standard provides the tolerances that must be met during the test for each test parameter. The specified methyl iodide penetration value is based on the assumptions used in the LOCA Analysis.

3/4.7.6 SNUBBERS

All snubbers are required OPERABLE to ensure that the structural integrity of the Reactor Coolant System and all other safety-related systems is maintained during and following a seismic or other event initiating dynamic loads.

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TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.6 SNUBBERS (Continued)

The visual inspection frequency is based upon maintaining a constant level of snubber protection to each safety-related system during an earthquake or severe transient. Therefore, the required inspection interval varies inversely with the observed snubber failures and is determined by the number of inoperable snubbers found during an inspection. Inspections performed before that interval has elapsed may be used as a new reference point to determine the next inspection. However, the results of such early inspections performed before the original required time interval has elapsed (nominal time less 25%) may not be used to lengthen the required inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule.

When the cause of the rejection of a snubber is visual inspection is clearly established and remedied for the snubber and for any other snubbers that may be generically susceptible, and verified operable by inservice functional testing, that snubber may be exempted from being counted as inoperable for the purposes of establishing the next visual inspection interval. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, or are similarly located or exposed to the same environmental conditions such as temperature, radiation, and vibration.

When a snubber is found inoperable, an evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any Safety Related System or component has been adversely affected by the inoperability of the snubber. The evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system.

To provide assurance of snubber functional reliability, a representative sample of the installed snubbers will be functionally tested during plant refueling SHUTDOWNS. Observed failure of these sample snubbers shall require functional testing of additional units. In cases where the cause of the functional failure has been identified additional testing shall be based on manufacturer's or engineering recommendations. As applicable, this additional testing increases the probability of locating possible inoperable snubbers without testing 100% of the safety-related snubbers.

The service life of a snubber is established via manufacturer input and information through consideration of the snubber service conditions and associated installation and maintenance records (newly installed snubbers, seal replaced, spring replaced, in high radiation area, in high temperature area, etc.). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

TECHNICAL SPECIFICATION BASES

3/4.7 PLANT SYSTEMS (Continued)

3/4.7.7 SEALED SOURCE CONTAMINATION

The limitations on removable contamination for sources requiring leak testing, including alpha emitters, is based on 10 CFR 70.39(a)(3) limits for plutonium. This limitation will ensure that leakage from Byproduct, Source, and Special Nuclear Material sources will not exceed allowable intake values.

Sealed sources are classified into three groups according to their use, with Surveillance Requirements commensurate with the probability of damage to a source in that group. Those sources which are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism (i.e., sealed sources within radiation monitoring or boron measuring devices) are considered to be stored and need not be tested unless they are removed from the shielded mechanism.

3/4.7.8 EXPLOSIVE GAS MIXTURE

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the GAS DECAY TANK SYSTEM (as measured in the inservice gas decay tank) is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of hydrogen and oxygen below their flammability limits provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

3/4 7.9 GAS DECAY TANKS

The tanks included in this specification are those tanks for which the quantity of radioactivity contained is not limited directly or indirectly by another Technical Specification. Restricting the quantity of radioactivity contained in each Gas Decay Tank provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting whole body exposure to a MEMBER OF THE PUBLIC at the nearest SITE BOUNDARY will not exceed 0.5 rem.

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION

The OPERABILITY of the A.C. and D.C power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety-related equipment required for (1) the safe shutdown of the facility, and (2) the mitigation and control of accident conditions within the facility.

The loss of an associated diesel generator for system(s), subsystem(s), train(s), component(s) or device(s) does not result in the system(s), subsystem(s), train(s), component(s) or device(s) being considered inoperable for the purpose of satisfying the requirements of its applicable Limiting Condition for Operation for the affected unit provided (1) its corresponding normal power source is OPERABLE; and (2) its redundant system(s), subsystem(s), train(s), component(s), and device(s) that depend on the remaining OPERABLE diesel generators as a source emergency power to meet all applicable LCO's are OPERABLE. This allows operation to be governed by the time limits of the ACTION statement associated with the inoperable diesel generator, not the individual ACTION statements for each system, subsystem, train, component or device. However, due to the existence of shared systems, there are certain conditions that require special provisions. These provisions are stipulated in the appropriate LCO's as needed.

More specifically, LCO's 3.5.2 and 3.8.2.1 require that associated EDG's be OPERABLE in addition to requiring that Safety Injection pumps, battery chargers, and battery banks, respectively also be OPERABLE. This EDG requirement was placed in these particular LCO's due to the shared nature of these systems to ensure adequate EDG availability for the required components. A situation could arise where a unit in MODES 1,2,3, or 4 could be in full compliance with LCO 3.8.1.1, yet be using shared equipment that could be impacted by taking an EDG out-of-service on the opposite unit. In this situation, diesel generator ACTION 3.8.1.1.d which verifies redundant train OPERABILITY, may not be applicable to one of the units. Thus, specific requirements for EDG OPERABILITY have been added to the appropriate LCO's of the shared systems (3.5.2 and 3.8.2.1). It is important to note that in these particular LCO's, the inoperability of a required EDG does not constitute inoperability of the other components required to be OPERABLE in the LCO. Specific ACTION statements are included in 3.5.2 and 3.8.2.1 for those situations where the required components are OPERABLE (by the definition of OPERABILITY) but not capable of being powered by an OPERABLE EDG.

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TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION (Continued)

The ACTION requirements specified for the levels of degradation of the power sources provide restrictions upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources is consistent with the initial condition assumptions of the safety analysis and is based upon maintaining adequate onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss-of-offsite power and single failure of one onsite A.C. source. Two physically independent A.C. circuits exist between the offsite transmission network and the onsite Class 1E Distribution System by utilizing the following:

(1) a total of eight transmission lines which lead to five separate transmission substations tie the Turkey Point Switchyard to the offsite power grid;
(2) two dual-winding startup transformers each provide 100% of the A and B train 4160 volt power from the switchyard to its associated unit.

In addition, each startup transformer has the capability to supply backup power of approximately 2500 kw to the opposite unit's A-train 4160 volt bus. Two emergency diesel generators (EDG) provide onsite emergency A.C. power for each unit. EDG's 3A and 3B provide Unit 3 A-train, and B-train emergency power, respectively. EDG's 4A and 4B provide Unit 4 A-train and B-train emergency power, respectively.

Due to the shared nature of numerous electrical components between Turkey Point Units 3&4, the inoperability of a component on an associated unit will often affect the operation of the opposite unit. These shared electrical components consist primarily of both startup transformers, three out of four 4160 volt busses, and associated 480 volt motor control centers, all four 125 volt D.C. busses, all eight 120 volt vital A.C. panels and eight out of twelve vital A.C. inverters, four out of eight battery chargers, and all four battery banks. Depending on the component(s) which is (are) determined inoperable, the resulting ACTION can range from the eventual shutdown of the opposite unit long after the associated unit has been shutdown (30 days) to an immediate shutdown of both units. Therefore, ACTION times allow for an orderly sequential shutdown of both units when the inoperability of a component(s) affects both units with equal severity. When a single unit is affected, the time to be in HOT STANDBY is 6 hours. When an ACTION statement requires a dual unit shutdown, the time to be in HOT STANDBY is 12 hours. This is to allow the orderly shutdown of one unit at a time and not jeopardize the stability of the electrical grid by imposing a dual unit shutdown.

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TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION (Continued)

As each startup transformer only provides the limited equivalent power of approximately one EDG to the opposite Units A-train 4160 volt bus, the allowable out-of-service time of 30 days has been applied before the opposite unit is required to be shutdown. Within 24 hours, a unit with an inoperable startup transformer must reduce THERMAL POWER to less than or equal to 30% RATED THERMAL POWER. The 30% RATED THERMAL POWER limit was chosen because at this power level the decay heat and fission product production has been reduced and the operators are still able to maintain automatic control of the feedwater trains and other unit equipment. At lower power levels the operators must use manual control with the feedwater bypass lines. By not requiring a complete unit shutdown, the plant avoids a condition requiring natural circulation and avoids intentionally relying on engineered safety features for non-accident conditions.

With one startup transformer and one of the three required EDGs inoperable, the unit with the inoperable transformer must reduce THERMAL POWER to less than or equal to 30% RATED THERMAL POWER within 24 hours, based on the loss of its associated startup transformer, whereas operation of the unit with the OPERABLE transformer is controlled by the limits for inoperability of the EDG. The notification of a loss of startup transformer(s) to the NRC (ACTION STATEMENT 3.8.1.1.c) is not a 10 CFR 50.72/50.73 requirement and as such will be made for information purposes only to the NRC Operations Center via commercial lines.

With an EDG out of service, ACTION statement 3.8.1.1.b and Surveillance Requirement (SR) 4.8.1.1.1.a are provided to demonstrate operability of the required startup transformers and their associated circuits within 1 hour and at least once per 8 hours thereafter. For a planned EDG inoperability, SR 4.8.1.1.1.a may be performed up to 1 hour prior to rendering the EDG inoperable. The frequency of SR 4.8.1.1.1.a after it has been performed once, is at least once per 8 hours until the EDG is made operable again. When one diesel generator is inoperable, there is also an additional ACTION requirement to verify that required system(s), subsystem(s), train(s), component(s), and device(s) that depend on the remaining required OPERABLE diesel generators as a source of emergency power to meet all applicable LCO's, are OPERABLE. This requirement is intended to provide assurance that a loss-of-offsite power event will not result in a complete loss of safety function of critical systems during the period one of the diesel generators is inoperable. This requirement allows continued operation to be governed by the time limits of the ACTION statement associated with the inoperable diesel generator. The loss of a diesel generator does not result in the associated system(s), subsystem(s), train(s), component(s), or device(s) being considered inoperable provided: (1) its corresponding normal power source is OPERABLE: and (2) its redundant system(s), subsystem(s), train(s), component(s), and device(s) that depend on the remaining required OPERABLE diesel generators as a source of emergency power to meet all applicable LCO's, are OPERABLE.

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TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION (Continued)

All diesel generator inoperabilities must be investigated for common cause failures regardless of how long the diesel generator inoperability persists. When one diesel generator is inoperable, TS 3.8.1.1 ACTION statements b and c provide an allowance to avoid unnecessary testing of other required diesel generators. If it can be determined that the cause of the inoperable diesel generator does not exist on the remaining required diesel generators, then SR 4.8.1.1.2a.4 does not have to be performed. Twenty-four (24) hours (or eight (8) hours if both a startup transformer and diesel generator are inoperable) is reasonable to confirm that the remaining required diesel generators are not affected by the same problem as the inoperable diesel generator. If it cannot otherwise be determined that the cause of the initial inoperable diesel generator does not exist on the remaining required diesel generators, then satisfactory performance of SR 4.8.1.1.2a.4 suffices to provide assurance of continued OPERABILITY of the remaining required diesel generators. If the cause of the initial inoperability exists on one or more of the remaining required diesel generators, those diesel generators affected would also be declared inoperable upon discovery, and TS 3.8.1.1 ACTION statement f or TS 3.0.3, as appropriate, would apply.

When in Modes 1, 2, 3 or 4, a unit depends on one EDG and its associated train of busses from the opposite unit in order to satisfy the single active failure criterion for safety injection (SI) pumps and other shared equipment required during a loss-of-coolant accident with a loss-of-offsite power. Therefore, one EDG from the opposite unit is required to be OPERABLE along with the two EDG's associated with the applicable unit.

For single unit operation (one unit in Modes 1-4 and one unit in Modes 5-6 or defueled) TS 3.8.1.1 ACTION d. refers to one of the three required emergency diesel generators. For dual unit operation (both units in Modes 1-4), TS 3.8.1.1 ACTION d. refers to one of the four required emergency diesel generators. This conclusion is based on the portion of ACTION d. that states "... in addition to ACTION b. or c. ...." Since ACTIONs b. and c. both refer to "one of the required diesel generators," this implies that ACTION d. also refers to one of the required diesel generators. ACTION d. says "in addition to ACTION b. or c. above, ..." therefore ACTION d. is merely providing additional requirements applicable to the conditions that required satisfaction of ACTIONs b. or c.

With both startup transformers inoperable, the unit(s) are required to be shutdown consecutively, after 24 hours. A consecutive shutdown is used because a unit without its associated transformer must perform a natural circulation cooldown. By placing one unit in COLD SHUTDOWN before starting shutdown of the second unit, a dual unit natural circulation cooldown is avoided.

The term verify means to administratively check by examining logs or other information to determine if required components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION (Continued)

In accordance with Technical Specification Amendments 215/209 during Modes 1, 2, and 3, if an EDG is to be removed from service for maintenance for a period scheduled to exceed 72 hours, the following restrictions apply:

If an EDG is unavailable, the startup transformer will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If the Startup Transformer is unavailable, an EDG will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If an EDG is unavailable, an EDG on the opposite unit will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If the Blackout crosstie is unavailable, an EDG will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If an EDG is unavailable, the Blackout Crosstie will be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If a condition is entered in which both an EDG and the Blackout Crosstie are unavailable at the same time, restore the EDG or Blackout Crosstie to service as soon as possible.

If a hurricane warning has been issued in an area which may impact the FPL grid, i.e., within the FPL service area, an EDG or the Blackout Crosstie should be removed from service only for corrective maintenance, i.e., maintenance required to ensure or restore operability.

If an EDG or the Blackout Crosstie is unavailable when a hurricane warning in an area that may impact the FPL grid is issued, the unavailable component(s) will be restored to service as soon as possible.

If a tornado watch has been issued for an area which includes the Turkey Point Plant site, and/or the substations and transmission lines serving Turkey Point Plant switchyard, restore the unavailable component(s) to service as soon as possible.

To address the potential fire risk implications during Modes 1, 2, and 3, if an EDG is to be removed from service for maintenance for a period scheduled to exceed 72 hours, the following actions will be completed:

A plant fire protection walkdown of the areas that could impact EDG availability, offsite power availability or the ability to use the Station Blackout Crosstie prior to entering the extended allowed outage time (AOT).

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION (Continued)

A thermographic examination of high-risk potential ignition sources in the Cable Spreading Room and the Control Room,

Restriction of planned hot work in the Cable Spreading Room and Control Room during the extended AOT, and

Establishment of a continuous fire watch in the Cable Spreading Room when in the extended AOT.

In addition to the predetermined restrictions, assessments performed in accordance with the provisions of the Maintenance Rule (a)(4) will ensure that any other risk significant configurations are identified before removing an EDG from service for pre-planned maintenance.

A configuration risk management program has been established at Turkey Point 3 and 4 via the implementation of the Maintenance Rule and the On line Risk Monitor to ensure the risk impact of out of service equipment is appropriately evaluated prior to performing any maintenance activity.

The Surveillance Requirements for demonstrating the OPERABILITY of the diesel generators are in accordance with the recommendations of Regulatory Guides 1.9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971; 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977; and 1.137, "Fuel-oil Systems for Standby Diesel Generators," Revision 1, October 1979.

The EDG Surveillance testing requires that each EDG be started from normal conditions only once per 184 days with no additional warmup procedures.

Normal conditions in this instance are defined as the pre-start temperature and lube oil conditions each EDG normally experiences with the continuous use of prelube systems and immersion heaters.

Surveillance Requirement 4.8.1.1.2.b demonstrates that each required fuel oil transfer pump operates and is capable of transferring fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This surveillance provides assurance that the fuel oil transfer pump and its control systems are capable of performing their associated support functions, and that the fuel oil piping system is intact and not obstructed. Instrument air shall be available when performing this surveillance test. If the instrument air system is not available, OPERABILITY of the EDG can be demonstrated by using a portable air or nitrogen source to locally open the EDG day tank fill valve. Normal Instrument air supply to the fill valve must be restored when the instrument air system is returned to service to maintain automatic operation of the system in accordance with the diesel fuel oil transfer system design basis.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

3/4.8.1, 3/4.8.2, and 3/4.8.3 A.C. SOURCES, D.C. SOURCES, and ONSITE POWER DISTRIBUTION (Continued)

Surveillance Requirement 4.8.1.1.2.g.7) demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal surveillances, and achieve the required voltage and frequency within 15 seconds. The 15 second time is derived from the requirements of the accident analysis to respond to a design large break Loss of Coolant Accident (LOCA). By performing this SR after 24 hours (or after two hours, in accordance with the proposed revised footnote), the test is performed with the diesel sufficiently hot. The load band is provided to avoid routine overloading of the EDG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY. The requirement that the diesel has operated for at least two hours at full load is based on NRC staff guidance for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test.

In accordance with Technical Specification Amendments 215/209, the EDGs will be inspected in accordance with a licensee controlled maintenance program referenced in the UFSAR. The maintenance program will require inspections in accordance with procedures prepared in conjunction with the manufacturer's recommendations for this class of standby service. Changes to the maintenance program will be controlled under 10 CFR 50.59.

The fuel supply specified for the Unit 3 EDG's is based on the original criteria and design bases used to license the plant. The specified fuel supply (diesel oil storage tank or temporary storage system) will ensure sufficient fuel for either EDG associated with Unit 3 for at least a week. The fuel supply specified for the Unit 4 EDG's is based on the criteria provided in ANSI N195-1976 as endorsed by Regulatory Guide 1.137. The specified fuel supply will ensure sufficient fuel for each EDG associated with Unit 4 for at least a week.

Surveillance Requirement 4.8.1.1.2.g.7, verifying that the diesel generator operates for at least 24 hours, may be performed during POWER OPERATION (Mode 1) per Licensing Amendment # 221/215.

DIESEL FUEL OIL TESTING PROGRAM

In accordance with TS 6.8.4, a diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. For the intent of this specification, new fuel oil shall represent diesel fuel oil that has not been added to the Diesel Fuel Oil Storage Tanks. Once the fuel oil is added to the Diesel Fuel Oil Storage Tanks, the diesel fuel oil is considered stored fuel oil, and shall meet the Technical Specification requirements for stored diesel fuel oil.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

The tests listed below are a means of determining whether new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the new fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. These tests are to be conducted prior to adding the new fuel to the storage tanks, but in no case is the time between receipt of the new fuel oil and conducting the tests of Surveillance Requirement 4.8.1.1.2e. to exceed 30 days. The tests, limits, and applicable ASTM standards being used to evaluate the condition of new fuel oil are:

1. By obtaining a composite sample of new fuel oil in accordance with ASTM-D4057 prior to addition of new fuel oil to the diesel fuel oil storage tanks and:

2. By verifying in accordance with the tests specified in ASTM-D975-81 prior to addition to the diesel fuel oil storage tanks that the sample has:

   a) An API Gravity of within 0.3 degrees at 60°F, or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate, or an absolute specific gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89, or an API gravity of greater than or equal to 27 degrees but less than or equal to 39 degrees, when tested in accordance with ASTM-D1298-80;

   b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes (alternatively, Saybolt viscosity, SUS at 100°F of greater than or equal to 32.6, but less than or equal to 40.1), if gravity was not determined by comparison with the supplier's certification;

   c) A flash point equal to or greater than 125°F; and

   d) A clear and bright appearance with proper color when tested in accordance with ASTM-D4176-82.

Failure to meet any of the above limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the Limiting Condition for Operation of TS 3.8.1.1, since the new fuel oil has not been added to the diesel fuel oil storage tanks.

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

Within 30 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM-D975-81 are met when tested in accordance with ASTM–D975-81 except that the analysis for sulfur may be performed in accordance with ASTM–D1552-79 or ASTM-D2622-82. The 30 day period is acceptable because the fuel oil properties of interest, even if they are not within limits, would not have an immediate effect on EDG operation. The diesel fuel oil surveillance in accordance with the Diesel Fuel Oil Testing Program will ensure the availability of high quality diesel fuel oil for the EDGs.

At least once every 31 days, a sample of fuel oil is obtained from the storage tanks in accordance with ASTM-D2276-78. The particulate contamination is verified to be less than 10 mg/liter when checked in accordance with ASTM-D2276-78, Method A. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure.

The frequency for performing surveillance on stored fuel oil is based on stored fuel oil degradation trends which indicate that particulate concentration is unlikely to change significantly between surveillances.

The OPERABILITY of the minimum specified A.C. and D.C. power sources and associated distribution systems during shutdown and refueling ensures that (1) the facility can be maintained in the shutdown or refueling condition for extended time periods, and (2) sufficient instrumentation and control capability is available for monitoring and maintaining the unit status.

During a unit shutdown, the one required circuit between the offsite transmission network and the onsite Class 1E Distribution System can consist of at least the associated unit startup transformer feeding one 4160 volt Bus A or B, or the opposite unit's startup transformer feeding the associated unit's 4160 volt Bus A, or the associated unit's 4160 volt Bus A or B backfed through its auxiliary transformers with the main generator isolated.

As inoperability of numerous electrical components often affects the operation of the opposite unit, the applicability for the shutdown LIMITING CONDITION FOR OPERATION (LCO) for A.C. Sources, D.C. Sources and Onsite Power Distribution all contain statements to ensure the LCO's of the opposite unit are considered.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

The allowable out-of-service time for the D.C. busses is 24 hours with one unit shutdown in order to allow for required battery maintenance without requiring both units to be shutdown. Provisions to substitute the spare battery for any one of the four station batteries have been included to allow for battery maintenance without requiring both units to be shutdown. The requirement to have only one OPERABLE battery charger associated with a required battery bank permits maintenance to be conducted on the redundant battery charger.

A battery charger may be considered acceptable when supplying less than 10 amperes provided:

1) The battery charger's ability to independently accept and supply the D.C. bus has been verified within the previous 7 days and

2) D.C. output voltage is $\geq$ 129 volts.

The minimum number of battery chargers required to be OPERABLE is based on the following criteria:

1) A minimum of one battery charger per bus with each powered from a separate 480 volt MCC is required to satisfy the single failure criteria when assuming the failure of a MCC. This restriction prohibits the use of two chargers powered from the same bus for meeting the minimum requirements.

2) To satisfy the single failure criteria, when assuming a loss-of-offsite power with the loss of an EDG, an additional restriction is stipulated which requires each battery charger to have its associated diesel generator(s) OPERABLE. This requires both EDG's associated with a swing bus battery charger to be OPERABLE.

Provisions for requiring the OPERABILITY of the EDG associated with the battery charger is explicitly specified in the LCO. This is because conditions exist where the affected unit would not enter the applicable ACTION statement in the LCO without this provision. For example, with Unit 3 in MODE 1 and Unit 4 in MODE 5, the operability of both EDG 4A and 4B is not required. One could postulate conditions where battery chargers 4A1, 3A2, 3B2, or 4B1 could be used to satisfy the LCO without having an associated OPERABLE EDG, unless specific provisions were made to preclude these conditions.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

An out-of-service limit of 72 hours is applied when the required EDG is not OPERABLE. With less than the required battery chargers OPERABLE, an allowable out-of-service time of 2 hours is applied, which can be extended to 24 hours if the opposite unit is in MODES 5 or 6 and each of the remaining required battery chargers is capable of being powered from its associated diesel generator(s).

Verifying average electrolyte temperature above the minimum for which the battery was sized, total battery terminal voltage on float charge, connection resistance values, and the performance of battery service and discharge tests ensure the effectiveness of the charging system, the ability to handle high discharge rates, and verifies the battery capability to supply its required load.

Table 4.8-2 specifies the normal limits for each designated pilot cell and each connected cell for electrolyte level, float voltage, and specific gravity. The limits for the designated pilot cell's float voltage and specific gravity, greater than 2.13 volts and not more than 0.015 below the manufacturer's full charge specific gravity or a battery charger current that had stabilized at a low value, is characteristic of a charged cell with adequate capacity. The normal limits for each connected cell for float voltage and specific gravity, greater than 2.13 volts and not more than 0.020 below the manufacturer's full charge specific gravity with an average specific gravity of all connected cells not more than 0.010 below the manufacturer's full charge specific gravity, ensures the OPERABILITY and capability of the battery.

Operation with a battery cell's parameter outside the normal limit but within the allowable value specified in Table 4.8-2 is permitted for up to 7 days. During this period: (1) the allowable values for electrolyte level ensures no physical damage to the plates with an adequate electron transfer capability; (2) the allowable value for the average specific gravity of all the cells, not more than 0.020 below the manufacturer's recommended full charge specific gravity, ensures that the decrease in rating will be less than the safety margin provided in sizing; (3) the allowable value for an individual cell's specific gravity ensures that an individual cell's specific gravity will not be more than 0.040 below the manufacturer's full charge specific gravity and that the overall capability of the battery will be maintained within an acceptable limit; and (4) the allowable value for an individual cell's float voltage, greater than or equal to 2.07 volts, ensures the battery's capability to perform its design function.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

The ACTION requirements specified for the inoperability of certain Motor Control Centers (MCCs), Load Centers (LCs) and the 4160-Volt Busses provide restrictions upon continued facility operation commensurate with the level of degradation on each unit and the amount of time one could reasonably diagnose and correct a minor problem. The level of degradation is based upon the types of equipment powered and the out-of-service limit imposed on that equipment by the associated ACTION statement. If this degradation affects the associated unit only, then no restriction is placed on the opposite unit and an out-of-service limit of 8 hours (except for MCC's 3A, 3K, 4J and 4K) is applied to the associated unit. Since MCC's 3A, 3K, 4J and 4K are used to power EDG auxiliaries, an out-of-service limit of 72 hours is applied as required by 3.8.1.1. If the degradation impacts both units (i.e., required shared systems or cross-unit loads), then an out-of-service limit of 8 hours is applied to the associated unit and an out-of-service limit based on the most restrictive ACTION requirement for the applicable shared or cross-unit load is applied to the opposite unit.

For example, if being used to satisfy 3.8.2.1, the Battery Chargers 3A2, 3B2, 4A2, and 4B2 are cross-unit loads and have out-of-service limits of 2 hours. This is the most restrictive limit of the applicable equipment powered from MCC 3D and 4D. Therefore, an out-of-service limit of 2 hours is applied if the battery charger is required to be OPERABLE.

The ACTION requirements specified when an A.C. vital panel is not energized from an inverter connected to its associated D.C. bus provides for two phases of restoration. Expedient restoration of an A.C. panel is required due to the degradation of the Reactor Protection System and vital instrumentation. The first phase requires reenergization of the A.C. vital panel within two hours. During this phase the panel may be powered by a Class 1E constant voltage transformer (CVT) fed from a vital MCC. However, the condition is permissible for only 24 hours as the second phase of the ACTION requires reenergization of the A.C. vital panel from an inverter connected to its associated D.C. bus within 24 hours. Failure to satisfy these ACTIONS results in a dual unit shutdown.

Chapter 8 of the UFSAR provides the description of the A.C. electrical distribution system. The 480 Volt Load Center busses are arranged in an identical manner for Units 3 and 4. For each unit there are five safety related 480v load center busses, four of which are energized from different 4.16 kv busses (Load Centers A and C are fed from Train A and Load Centers B and D are fed from Train B). This arrangement ensures the availability of equipment associated with a particular function in the event of loss of one 4.16 kV bus.

The fifth safety related 480V load center in each unit is a swing load center, which can swing between Load Center C and D of its associated unit. These load centers are labeled as 3H for Unit 3 and 4H for Unit 4. When the 480V swing load center is connected to either 480V supply bus, it is considered to be an extension of that 480V supply bus.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

Technical Specification 3/4.8.3.1 states that, ... the electrical busses shall be energized in the specified manner...

Footnote 3.8.3.1*** states in part, Electrical bus can be energized from either train of its unit....

These statements establish that the load center is an extension of the train it is supplied from, and the associated bus is energized in the specified manner when it is supplying the load center.

The second half of the footnote pertains to the swing capability of the LC, and reads, ...and swing function to opposite train must be OPERABLE for the Unit(s) in MODES 1, 2, 3, and 4.

Although the swing load center swing function may be inoperable, the associated bus and swing loads are clearly OPERABLE, because the associated train was established by the first half of the footnote. The swing bus is capable of being powered from the opposite train, and the swing function is only applicable to the opposite train. If the swing LC cannot be powered from, or swing to, the opposite train, then the opposite train is incapable of being fully energized and is INOPERABLE.

Therefore, the correct interpretation of the footnote for the swing LCs and MCCs is as follows:

> Electrical bus can be energized from either train of its unit (establishes the associated bus) and swing function to opposite train must be OPERABLE for the Unit(s) in MODES 1, 2, 3, and 4 (or the opposite train is INOPERABLE).

The swing load centers are used to supply shared system and cross-unit loads, and other Technical Specification ACTION statements may be invoked for loss of swing capability. As discussed above, the Unit 3 DC battery chargers 3A2 and 3B2 are powered from Unit 4 via swing MCC 4D, and the Unit 4 DC battery chargers 4A2 and 4B2 are powered from Unit 3 via swing MCC 3D. Inoperability of the swing capability could impact both units if any of the swing battery chargers is credited for satisfying Technical Specification 3.8.2.1. Both EDGs are required to be OPERABLE for a swing battery charger. An inoperable swing function prevents one EDG from supporting that battery charger, and a dual-unit 72 hour ACTION statement applies in accordance with TS 3.8.2.1 ACTION statement a.

With a unit shutdown one 4160-volt bus on the associated unit can be deenergized for periodic refueling outage maintenance. The associated 480-volt Load Centers can then be cross-tied upon issuance of an engineering evaluation.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

For the shutdown unit, the swing load center does not have to be powered from a diesel-backed source, since:

a) Technical Specification 3.8.3.2 only requires that the swing load center be energized. No operability requirements are specified for the swing function (as opposed to the requirements for an operating unit); and

b) The only accident postulated to occur in Modes 5 and 6 is a fuel handling accident. Loss of offsite power is not assumed to occur concurrently with these events. Additionally, there is no causal relationship between a fuel handling event and a loss of offsite power. Thus, from a design basis standpoint, all of the control room HVAC safety functions can be accomplished with the swing load center energized from an offsite source.

Operating units on the other hand are subject to accidents that can both affect the grid, and release radioactivity to the outside environment, e.g., LOCA, MSLB. Thus, to satisfy the design basis requirements for the control room HVAC system when a unit is in Modes 1 – 4, the swing load center must be powered from a diesel-backed source.

For an operating unit, the swing load center also has to be powered from a diesel-backed source to be considered OPERABLE. The swing load center is considered to be powered from a diesel-backed source if:

a) it is connected to an electrical power train that has an operable diesel generator, or

b) it can automatically transfer to a bus that has an operable diesel generator.

If Load Center H is energized from a load center (either C or D) that does not have an operable emergency diesel generator aligned to it and the swing function is also inoperable, then a 2-hour or a 72-hour LCO would have to be entered, depending on the battery charger requirements (Technical specification Tables 3.8-1 and 3.8-2).

The swing load center will momentarily de-energize any time it transfers between supply busses (manual, automatic, or test conditions). Since this is the specified manner of operation, the momentary load center de-energization does not require entry into the Technical Specification 3/4.8.3.2 action statement.

ATTACHMENT 1
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TECHNICAL SPECIFICATION BASES

3/4.8 ELECTRICAL POWER SYSTEMS (Continued)

DIESEL FUEL OIL TESTING PROGRAM (Continued)

Although Load Center H is de-energized for a short period of time (~1.5 seconds), it is considered to be energized in the "specified manner." The design of the transfer scheme inherently relies on "break before make" contacts to swing between the two redundancy supply busses. The design allows for a total of 2.5 seconds to accomplish the automatic transfer – 1.5 seconds to trip the supply breaker of the aligned train and an additional 1.0 second delay (i.e., dead time) to close the opposite train supply breaker. This prevents the A and B trains from being interconnected during the transfer function. The basic concept of the transfer is that the transfer only occurs on a "dead" bus. This is accomplished by tripping and verifying that the bus is "dead" prior to closing the supply breaker to the alternate power supply.

Vital sections of the MCCs shown in the following table must be energized to satisfy Technical Specification Action 3.8.3.2.a:

Train in Service	3A	3B	4A	4B	Reason
MCCS	3A	3B	4A	4B	Major Safety MCCs
	3C		4C		Major Safety MCCs
	3D	3D	4D	4D	CR HVAC
		3K	4J	4K	EDG Auxiliaries

MCCs 3K, 4J, and 4K were added during the EPS Upgrade Project. Auxiliaries for the 3A EDG were left on the 3A MCC. As a result, only Unit 4 Train A needs four MCC vital sections energized, as shown on the Table above.

The No Significant Hazards Determination for the EPS Upgrade Technical Specifications stated, The description of the 480 volt emergency bus requirements has been modified to reflect additional LCs and MCCs added by the EPS Enhancement Project. Due to the addition of new LCs 3H/4H, MCCs 3K/4K, MCC 4D and MCC 4J, the LCO now requires the availability of three 480 volt LCs and three MCC bus vital sections (four MCC bus vital sections for Unit 4).

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.9 REFUELING OPERATIONS

3/4.9.1 BORON CONCENTRATION

The limitations on reactivity conditions during REFUELING ensure that: (1) the reactor will remain subcritical during CORE ALTERATIONS, and (2) a uniform boron concentration is maintained for reactivity control in the water volume having direct access to the reactor vessel. These limitations are consistent with the initial conditions assumed for the boron dilution incident in the safety analyses. With the required valves closed during refueling operations the possibility of uncontrolled boron dilution of the filled portion of the RCS is precluded. This action prevents flow to the RCS of unborated water by closing flow paths from sources of unborated water. The boration rate requirement of 16 gpm of 3.0 wt% (5245 ppm) boron or equivalent ensures the capability to restore the SHUTDOWN MARGIN with one OPERABLE charging pump.

3/4.9.2 INSTRUMENTATION

The OPERABILITY of the Source Range Neutron Flux Monitors ensures that redundant monitoring capability is available to detect changes in the reactivity condition of the core. There are four source range neutron flux channels, two primary and two backup. All four channels have visual and alarm indication in the control room and interface with the containment evacuation alarm system. The primary source range neutron flux channels can also generate reactor trip signals and provide audible indication of the count rate in the control room and containment. At least one primary source range neutron flux channel to provide the required audible indication, in addition to its other functions, and one of the three remaining source range channels shall be OPERABLE to satisfy the LCO.

3/4.9.3 DECAY TIME

The minimum requirement for reactor subcriticality prior to movement of irradiated fuel assemblies in the reactor vessel ensures that sufficient time has elapsed to allow the radioactive decay of short-lived fission products. This decay time is consistent with the assumptions used in the safety analyses, and ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the values specified in 10 CFR 50.67 and RG 1.183.

ATTACHMENT 1
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TECHNICAL SPECIFICATION BASES

3/4.9 REFUELING OPERATIONS (Continued)

3/4.9.4 CONTAINMENT BUILDING PENETRATIONS

This TS is applicable during movement of recently irradiated fuel assemblies within containment. Recently irradiated fuel is defined as fuel that has occupied part of a critical reactor core within the previous 72 hours. However, the administrative controls as well as the inherent delay associated with completing the required preparatory steps for moving fuel in the reactor vessel will ensure that the proposed 72-hour decay time will be met prior to removing irradiated fuel from the reactor vessel for a refueling outage. The FHA is a postulated event that involves damage to irradiated fuel. The in-containment FHA involves dropping a single irradiated fuel assembly, resulting in damage to a single fuel assembly. The 72-hour required decay time before moving fuel in containment ensures that sufficient time has elapsed to allow the radioactive decay of short-lived fission products. This decay time is consistent with the assumptions used in the safety analyses, and ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the values specified in 10 CFR 50.67 and RG 1.183.

FPL revised the design basis for the Turkey Point Units 3 and 4 FHA analysis using the Alternate Source Term (AST) methodology. This is a selective implementation of the AST methodology, and the calculations were done in accordance with Reg. Guide (RG) 1.183, “Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors.”

The containment airlocks, which are part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 operation. During periods of shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, both doors of the containment personnel airlock may be open provided (a) at least one personnel airlock door is capable of being closed, (b) the plant is in MODE 6 with at least 23 feet of water above the fuel, and (c) a designated individual is available outside the personnel airlock to close the door.

The containment equipment door, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During CORE ALTERATIONS the containment equipment door can be open. FPL has committed to implement the guidelines of NUMARC 93-01, Rev. 3, Section 11.3.6.5, which require (1) assessment of the availability of containment ventilation and containment radiation monitoring [satisfied by compliance with TS 3.9.9 and 3.9.13, respectively], and (2) development of a prompt method of closure of containment penetrations. Administrative controls have been developed to satisfy this commitment (ref: L-2001-201).

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.9 REFUELING OPERATIONS (Continued)

3/4.9.4 CONTAINMENT BUILDING PENETRATIONS (Continued)

Containment closure ensures that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling. The presence of a designated individual available outside of the personnel airlock to close the door, and a designated crew available to close the equipment door will minimize the release of radioactive materials.

Administrative requirements are established for the responsibilities and appropriate actions of the designated individuals in the event of a FHA inside containment. These requirements include the responsibility to be able to communicate with the control room, to ensure that the equipment door is capable of being closed, and to close the equipment door in the event of a fuel handling accident. These administrative controls ensure containment closure will be established in the event of a fuel handling accident inside containment. In accordance with Regulatory Guide 1 .183, these administrative controls assure that the personnel airlock and equipment door will be closed within 30 minutes.

3/4.9.5 COMMUNICATIONS

The requirement for communications capability ensures that refueling station personnel can be promptly informed of significant changes in the facility status or core reactivity conditions during CORE ALTERATIONS.

3/4.9.6 MANIPULATOR CRANE

The OPERABILITY requirements for the manipulator cranes ensure that: (1) manipulator cranes will be used for movement of drive rods and fuel assemblies, (2) each crane has sufficient load capacity to lift a drive rod or fuel assembly, and (3) the core internals and reactor vessel are protected from excessive lifting force in the event they are inadvertently engaged during lifting operations.

The requirement that the auxiliary hoist load indicator be used to prevent lifting excessive loads will require a manual action. The auxiliary hoist load indicator does not include any automatic mechanical or electrical interlocks that prevent lifting loads in excess of 600 pounds.

3/4.9.7 CRANE TRAVEL - SPENT FUEL STORAGE AREAS

The restriction on movement of loads in excess of the nominal weight of a fuel and control rod assembly and associated handling tool over other fuel assemblies in the storage pool ensures that in the event this load is dropped: (1) the activity release will be limited to that contained in a single fuel assembly, and (2) any possible distortion of fuel in the storage racks will not result in a critical array. This assumption is consistent with the activity release assumed in the safety analyses.

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TECHNICAL SPECIFICATION BASES

3/4.9 REFUELING OPERATIONS (Continued)

3/4.9.8 RESIDUAL HEAT REMOVAL AND COOLANT CIRCULATION

The requirement that at least one residual heat removal (RHR) loop be in operation ensures that: (1) sufficient cooling capacity is available to remove decay heat and maintain the water in the reactor vessel below 140°F as required during the REFUELING MODE, and (2) sufficient coolant circulation is maintained through the core to minimize the effect of a boron dilution incident and prevent boron stratification.

The requirement to have two RHR loops OPERABLE when there is less than 23 feet of water above the reactor vessel flange ensures that a single failure of the operating RHR loop will not result in a complete loss of residual heat removal capability. With the reactor vessel head removed and at least 23 feet of water above the reactor pressure vessel flange, a large heat sink is available for core cooling. Thus, in the event of a failure of the operating RHR loop, adequate time is provided to initiate emergency procedures to cool the core.

3/4.9.9 CONTAINMENT VENTILATION ISOLATION SYSTEM

The OPERABILITY of this system ensures that the containment ventilation penetrations will be automatically isolated upon detection of high radiation levels within the containment. The OPERABILITY of this system is required to restrict the release of radioactive material from the containment atmosphere to the environment.

3/4.9.10 and 3/4.9.11 WATER LEVEL – REACTOR VESSEL AND STORAGE POOL

The restrictions on minimum water level ensure that sufficient shielding will be available during fuel movement and for removal of iodine in the event of a fuel handling accident. The minimum water depth is consistent with the assumptions of the safety analysis.

3/4.9.12 HANDLING OF SPENT FUEL CASK

Limiting spent fuel decay time from last time critical to a minimum of 1,525 hours prior to moving a spent fuel cask into the spent fuel pit will ensure that potential offsite doses are a fraction of 10 CFR Part 100 limits should a dropped cask strike the stored fuel assemblies.

The restriction to allow only a single element cask to be moved into the spent fuel pit will ensure the maintenance of water inventory in the unlikely event of an uncontrolled cask descent. Use of a single element cask which nominally weighs about twenty-five tons will also increase crane safety margins by about a factor of four.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.9 REFUELING OPERATIONS (Continued)

3/4.9.12 HANDLING OF SPENT FUEL CASK (Continued)

Requiring that spent fuel decay time from last time critical be at least 120 days prior to moving a fuel assembly outside the fuel storage pit in a shipping cask will ensure that potential offsite doses are a fraction of 10 CFR 100 limits should a dropped cask and ruptured fuel assembly release activity directly to the atmosphere.

3/4.9.13 RADIATION MONITORING

The OPERABILITY of the containment radiation monitors ensures continuous monitoring of radiation levels to provide immediate indication of an unsafe condition.

3/4.9.14 SPENT FUEL STORAGE

The spent fuel storage racks provide safe subcritical storage of fuel assemblies by providing sufficient center-to-center spacing or a combination of spacing and poison to assure: a) $K_{eff} \leq 0.95$ with a minimum soluble boron concentration of 650 ppm present, and b) $K_{eff} < 1.0$ when flooded with unborated water for normal operations and postulated accidents.

The spent fuel racks are divided into two regions. Region I racks have a 10.6 inch center-to-center spacing and Region II racks have a 9.0 inch center-to-center spacing. Because of the larger center-to-center spacing and poison (B^{10}) concentration of Region I cells, the only restriction for placement of fuel is that the initial fuel assembly enrichment is equal to or less than 4.5 weight percent of U-235. The limiting value of U-235 enrichment is based upon the assumptions in the spent fuel safety analyses and assures that the limiting criteria for criticality is not exceeded. Prior to placement in Region II cell locations, strict controls are employed to evaluate burnup of the spent fuel assembly. Upon determination that the fuel assembly meets the burnup requirements of Table 3.9-1, placement in a Region II cell is authorized. These positive controls assure that fuel enrichment limits assumed in the safety analyses will not be exceeded.

ATTACHMENT 1

TECHNICAL SPECIFICATION BASES

3/4.10 SPECIAL TEST EXCEPTIONS

3/4.10.1 SHUTDOWN MARGIN

This special test exception provides that a minimum amount of control rod worth is immediately available for reactivity control when tests are performed for control rod worth measurement. This special test exception is required to permit the periodic verification of the actual versus predicted core reactivity condition occurring as a result of fuel burnup or fuel cycling operations.

3/4.10.2 GROUP HEIGHT, INSERTION, AND POWER DISTRIBUTION LIMITS

This special test exception permits individual control rods to be positioned outside of their normal group heights and insertion limits during the performance of such PHYSICS TESTS as those required to measure control rod worth.

3/4.10.3 PHYSICS TESTS

This special test exception permits PHYSICS TESTS to be performed at less than or equal to 5% of RATED THERMAL POWER with the RCS T_{avg} slightly lower than normally allowed so that the fundamental nuclear characteristics of the core and related instrumentation can be verified. In order for various characteristics to be accurately measured, it is at times necessary to operate outside the normal restrictions of these Technical Specifications. For instance, to measure the moderator temperature coefficient at BOL, it is necessary to position the various control rods at heights which may not normally be allowed by Specification 3.1.3.6 which in turn may cause the RCS T_{avg} to fall slightly below the minimum temperature of Specification 3.1.1.4.

3/4.10.4 (This specification number is not used.)

3/4.10.5 POSITION INDICATION SYSTEM - SHUTDOWN

This special test exception permits the Position Indication Systems to be inoperable during rod drop time measurements. The exception is required since the data necessary to determine the rod drop time are derived from the induced voltage in the position indicator coils as the rod is dropped. This induced voltage is small compared to the normal voltage and, therefore, cannot be observed if the Position Indication Systems remain OPERABLE.

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